



50-454

UNITED STATES
NUCLEAR REGULATORY COMMISSION

WASHINGTON, D.C. 20545-0001

September 4, 1997

Ms. Irene M. Johnson, Acting Manager
Nuclear Regulatory Services
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Executive Towers West III
1400 Opus Place, Suite 500
Downers Grove, IL 60515

SUBJECT: REVIEW OF PRELIMINARY ACCIDENT SEQUENCE PRECURSOR ANALYSIS OF
OPERATIONAL EVENT AT BYRON STATION, UNIT 1

Dear Ms. Johnson:

Enclosed for your review and comment is a copy of the preliminary Accident Sequence Precursor (ASP) analysis of an operational event which occurred at Byron Station, Unit 1, on May 23, 1996 (Enclosure 1), and was reported in Licensee Event Report (LER) No. 454/96-007. This analysis was prepared by our contractor at the Oak Ridge National Laboratory (ORNL). The results of this preliminary analysis indicate that this condition may be an accident precursor for 1996. In assessing operational events, an effort was made to make the ASP models as realistic as possible regarding the specific features and response of a given plant to various accident sequence initiators. We realize that licensees may have additional systems and emergency procedures, or other features at their plants that might affect the analysis. Therefore, we are providing you an opportunity to review and comment on the technical adequacy of the preliminary ASP analysis, including the depiction of plant equipment and equipment capabilities. Upon receipt and evaluation of your comments, we will revise the conditional core damage probability calculations where necessary to consider the specific information you have provided. The object of the review process is to provide as realistic an analysis of the significance of the event as possible.

In order for us to incorporate your comments, perform any required reanalysis, and prepare the final report of our analysis of this event in a timely manner, you are requested to complete your review and to provide any comments within 30 days of receipt of this letter. We have streamlined the ASP Program with the objective of significantly improving the time after an event in which the final precursor analysis of the event is made publicly available. As soon as our final analysis of the event has been completed, we will provide for your information the final precursor analysis of the event and the resolution of your comments. In previous years, licensees have had to wait until publication of the Annual Precursor Report (in some cases, up to 23 months after an event) for the final precursor analysis of an event and the resolution of their comments.

We have also enclosed several items to facilitate your review. Enclosure 2 contains specific guidance for performing the requested review, identifies the criteria which we will apply to determine whether any credit should be given in the analysis for the use of licensee-identified additional equipment or

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specific actions in recovering from the event, and describes the specific information that you should provide to support such a claim. Enclosure 3 is a copy of LER No. 454/96-007, which documented the event.

Please contact me at (301) 415-3019 if you have any questions regarding this request. This request is covered by the existing OMB clearance number (3150-0104) for NRC staff followup review of events documented in LERs. Your response to this request is voluntary and does not constitute a licensing requirement.

Sincerely,

Original Signed By:

George F. Dick, Jr., Project Manager
Project Directorate III-2
Division of Reactor Projects III/IV
Office of Nuclear Reactor Regulation

Docket No. 50-454

Enclosures: As stated

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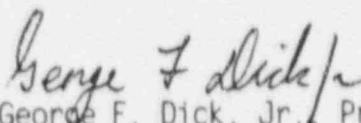
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LER No. 454/96-007

Event Description: Transformer bus fault causes a LOOP

Date of Event: May 23, 1996

Plant: Byron 1

Event Summary

When a fault occurred on the output bus from system auxiliary transformer (SAT) 142-2, protective relaying isolated the Unit 1 SATs, resulting in a complete loss of offsite power (LOOP) to Unit 1 (Ref. 1). The unit was shut down at the time, with the Residual Heat Removal (RHR) system being used for removing the decay heat from the core. All of the reactor coolant system (RCS) loop stop valves were closed at the time because of steam generator (SG) maintenance. The estimated conditional core damage probability (CCDP) associated with the event is 2.5×10^{-5} .

Event Description

Byron Unit 1 was in cold shutdown with reactor coolant pressure at 350 psig and reactor coolant temperature at 85°F, when a fault occurred at 0804 h on May 23, 1996, on the output of SAT 142-2. Water leaking through insulator mounting holes degraded the metal inserts in the insulator as well as the insulator material between the inserts. This initiated a phase-to-ground fault. The fault expanded to involve the other phases and switchyard protective relaying to isolated SATs 142-1 and 142-2. At the time, all 4.16 kV and 6.9 kV buses were powered from the SATs, so a complete LOOP resulted. Both emergency diesel generators (EDGs) started and loaded onto their respective engineered safety feature (ESF) buses. Shutdown cooling was restored using the 1A RHR pump.

At the time of the event, Unit 2 was operating at 100% power. Air compressors and non-essential service water for both units were being powered from non-ESF buses on Unit 1 (the Unit 2 station air compressor was out of service). As designed, these buses were not reenergized when the EDGs energized their respective ESF buses. Two minutes after the Unit 1 LOOP, plant operators manually scrammed Unit 2 because of the lack of station air and cooling water for plant secondary systems.

During a telephone call on May 19, 1997, with ASP Program staff, licensee personnel provided additional information concerning this event. Unit 1 had been shut down on April 5, 1997. At the time of this event, the RCS loop stop valves were closed, and the water was drained in the RCS piping between the loop stop valves and the SGs to support maintenance work that was in progress on the SGs. The water level in the pressurizer was at ~50%. Following the LOOP, the EDGs provided power to the ESF buses until personnel restored offsite power to SAT 142-1 at 1300 h on May 24, 1996 (29 h after the LOOP). The EDGs were operated instead of cross-tying the safety buses on the two units because of concern over the condition of the

buses following the fault. Following repairs and trouble shooting, offsite power was restored to SAT 142-2 on June 9, 1996.

Additional Event-Related Information

Normal ac power for nonessential and essential loads at Unit 1 is provided via a unit auxiliary transformer (UAT) and both SATs. During power operation, non-ESF buses (including the 6.9 kV buses that provide power to the reactor coolant pumps and other large electrical loads) are usually aligned to the UAT, which is fed from the output of the main generator. The ESF buses are connected via the SATs to the 345 kV transmission lines which supply offsite power. Each SAT serves as a reserve power source for the non-ESF buses as well as a second source of offsite power for the corresponding ESF bus at the other unit. Each SAT is capable of furnishing startup and limited operating loads.

Buses 141 and 142 at Unit 1 can be cross-tied to buses 241 and 242 at Unit 2, respectively, to provide ac power for ESF loads. Procedure IBOA ELEC-3, *Loss of 4 kV ESF Bus* (Ref. 2) specifies the actions required for protective load shedding, closing electrical breakers, and loading buses. If the battery charger associated with the ESF bus cannot be reenergized by cross-tying the ac buses, Ref. 2 instructs the operators to cross-tie the associated dc buses in the two units using procedure BOP DC-7, *125V DC ESF Bus Cross-tie/Restoration* (Ref. 3). This cross-tie can provide limited dc power.

The RHR system is provided with relief valves to prevent overpressurizing the system. Each RHR pump suction line is equipped with a relief valve set to lift at 450 psig. Below 200°F, each valve has a relief capacity of 675 gpm. At 375°F, the relief capacity of this valve is 475 gpm. Each RHR pump discharge line is equipped with a relief valve capable of relieving 400 gpm at a pressure of 600 psig. Two motor-operated gate valves in each suction line from the RCS are independently powered and interlocked to prevent these valves from opening above ~360 psig. An alarm is also provided to alert the operators in the event that double-valve isolation is not being maintained and if RCS pressure increases above 400 psig.

The RHR system is a two-train system that includes two cross-connect valves (RH8716A and B) in series in the discharge piping. These valves are normally open during power operation, but one is closed when entering Mode 4 (hot shutdown) to prevent potentially lifting a relief valve in the nonoperating train.* Closure of RH8716A or B isolates the two RHR trains, resulting in the availability of only one RHR suction and discharge relief valve for pressure relief when one RHR train is in use (the normal shutdown cooling alignment at Byron) (Ref. 4).

* This event actually happened. In 1989, an RHR suction relief valve on the nonoperating RHR train unexpectedly lifted at Braidwood (a plant similar to Byron) and failed to reseal. The operators at Braidwood initially assumed the valve was associated with the operating RHR train, and isolated that train. Sixty-four thousand gal of water were discharged before the open relief valve was found ninety-seven min after this event began. Flow from two charging pumps was required to reestablish the water level in the pressurizer. This event is documented in Appendix C of the 1989 ASP status report (NUREG/CR-4674, Vol. 12, August 1990).

According to licensee personnel, if ac power had not been recovered following the LOOP, the water in the core region would begin to boil in ~4.5 h and core uncover would occur in 9-10 h.

Modeling Assumptions

The Unit 1 event was analyzed as a LOOP during shutdown. The bus fault was the result of insulator degradation over an extended period of time, and it was considered unlikely that an additional fault could have occurred close in time on another bus. Because of this, the potential for a concurrent LOOP at Unit 2 was not addressed.

At the time of this event, the Unit 1 RCS loop isolation valves were closed and the water in the piping between the loop isolation valves and the SGs were drained to support maintenance work that was in progress on the SGs. The RCS was at 350 psig and 85°F, with the pressurizer one-half full. Following the LOOP, RHR cooling was momentarily lost until RHR train 1A was restarted after EDG 1A reenergized its ESF bus. Instrument air (IA) was lost because the operable station air compressors were powered from non-ESF Unit 1 buses.

If personnel could not reestablish cooling using the RHR system, Byron's procedure 1BOA PRI-10, *Loss of RHR Cooling, Unit 1* (Ref. 5), specifies several alternatives. For the plant condition that existed at the time of the LOOP, these alternatives include (1) feed-and-bleed cooling using normal charging and excess letdown through loop drains and (2) feed-and-bleed using normal charging and the pressurizer power-operated relief valves (PORVs). Two other methods (safety injection pump hot leg injection and accumulator injection) could potentially be adapted to provide decay heat removal, using the PORVs as a bleed path. At a minimum, this would require ac power to be available to at least one of the ESF buses. Use of the PORVs for bleed also requires ac power to be available to a non-ESF bus to provide power to one of the station air compressors, because IA is necessary for PORV operability during long-term feed-and-bleed. [If the PORVs were selected to "open" for feed-and-bleed prior to depleting the air in the reservoir, because of pressure cycling, then the PORVs could stay open for an extended period of time before air leakage depleted the reservoir. The open PORVs, in conjunction with manually opening the accumulator discharge valves, could extend the time until the onset of boiling in the core region. This potential recovery action (for which procedures do not exist) was not considered in this analysis.]

Because the current ASP models only address a LOOP at power, a separate shutdown event tree model was constructed to represent the conditions that existed during the actual event. Because of the multiplicity of decay heat removal methods and the need for ac power for all of them, the shutdown event tree model only addresses (1) the potential failure of the EDGs to start and load following the LOOP, and (2) the potential failure to recover ac power, if the EDGs were to fail. Once ac power is recovered, this analysis assumes that operator actions to recover RCS level, if necessary, and reestablish decay heat removal can be accomplished relatively easily. That is, the probability of failing to restore decay heat removal using one of the approaches

described in Ref. 5, given that ac power has been recovered, is assumed to be small compared to the probability of not recovering ac power.^b

The licensee estimated that if the EDGs failed to start following the LOOP and ac power was not subsequently recovered to allow the RHR system to be restarted, boiling in the region around the core would begin ~4.5 h after the LOOP. Up to this time, reactor coolant would expand slightly as its temperature increased because of decay heat, and would begin to fill the pressurizer with water. Depending on the specific conditions in the pressurizer, RCS pressure could increase to the 450-psig lift pressure of the RHR inlet relief valve. For the estimated decay heat level at the time of the LOOP (~4 MWt), the RHR inlet relief valve capacity is more than adequate to limit the pressure in the RCS to ~450 psig before boiling begins. Therefore, up to the point of boiling, the previously operating RHR pump could be restarted once ac power is available to its ESF bus in order to restore RHR (alternate decay heat removal methods specified in Ref. 6 could be used if the pump failed to start).

Once boiling begins, and water in the core region is converted to steam, the relief capacity required to prevent overpressurizing the RCS is substantially greater. This specific concern was addressed in NUREG/CR-6144 (Ref. 6) in the screening analysis performed in Phase 1 of the NRC's evaluation of potential risks during low power and shutdown operations at Surry. Appendix I to NUREG/CR-6144 estimates that if the RHR system was not isolated in response to high pressure at the onset of boiling, a relief capacity of 436 gpm is required for each MWt of decay heat. A relief capacity of ~1700 gpm would therefore be required to prevent overpressurizing the RHR system for the ~4 MWt decay heat load estimated to exist at the time of this event.

This relief capacity would initially be available, because the PORVs would be set for low temperature overpressure protection (LTOP). However, since IA was lost when the LOOP occurred, only a limited number of PORV cycles would be available until the in-containment PORV IA accumulator was depleted. Once the accumulator was depleted, the PORVs would cease to function. Since the suction and discharge relief valves in the operating RHR train cannot relieve the ~1700 gpm necessary to prevent overpressurizing the system, RCS and RHR system pressure would begin to increase, eventually resulting in RHR system rupture unless the RHR suction was manually isolated beforehand. The screening analysis in NUREG/CR-6144 assumed that overpressurizing the RHR system would result in a large-break LOCA and core damage. (Unlike Surry, Byron uses an RHR system that is located outside containment, like most pressurized water

^b The RHR train that was operating before the LOOP would remain configured for operation and only require restart of the RHR pump once ac power was recovered. Because of the short time that the pump would be stopped, standby-related failures-to-start would not substantially contribute to the pump failure to restart probability, leaving only demand-related failures. Such failures contribute ~15% to the total failure-to-start probability for motor-driven pumps [personal communication, E. Lofgren (SAIC) and J. Minarick (SAIC), July 2, 1997]. Considering only demand-related failures results in a failure to start probability for the previously operating train of ~4.5E-4. Combining this probability with the probability that the redundant RHR pump will suffer a demand-related failure to start ($\beta=0.1$ in the ASP models) or that other failures will occur in the redundant RHR train, and the probability of failure of feed-and-bleed cooling using a charging pump and the PORVs (estimated to be less than 0.02), results in an overall estimated failure of decay heat removal, given that ac power is available, of less than 1.0E-6.

reactors. An RHR system rupture at Byron would result in an interfacing system LOCA, which would be much more difficult to mitigate than a break inside containment.)

At about the same time that boiling would begin and the RCS and RHR systems would begin to pressurize, the Byron batteries would deplete. The batteries are sized to supply dc loads for 4 h.⁵ Once dc power is lost, indication of RCS status would be unavailable to the operators. Control power for circuit breaker operation would also be unavailable, which would further complicate recovery.

To address these issues, the model used in this analysis considered the potential failure of the EDGs to start and run for the 29-h period that offsite power was not recovered following the LOOP and the potential failure to recover ac power to one ESF bus, if the EDGs failed, before boiling began at ~4.5 h. (The 29 h period may be conservative. If emergency power had been lost, the licensee may have expedited the recovery of offsite power.) To simplify the analysis, battery depletion was also assumed to occur at 4.5 h. The potential for the operators to protect the RHR system from overpressure by manually closing one of the suction isolation valves (this does not appear to be addressed in Ref. 5) and restore ac power prior to core uncover (9-10 h), given that only dc power remained available once boiling began, is also addressed. Because the probability of RHR failing is low, given that ac power is successfully recovered, the potential failure of the RHR system and feed-and-bleed cooling is not included in the model.

The model for this event, shown in Fig. 1, includes the following branches:

- LOOP** The LOOP was caused by a fault on the output bus from SAT 142-2. Protective relaying isolated both Unit 1 SATs and resulted in a LOOP to Unit 1. The unit was in cold shutdown, with the RHR system in operation, the loop isolation valves closed and the SGs unavailable. A probability of 1.0 was assigned to the LOOP.
- EP** This branch represents the EDGs starting and running for the time period before offsite power was recovered. The licensee, in the May 19, 1997, telephone call noted that a conscious decision was made to power the ESF buses from the EDGs, instead of recovering offsite power using SAT 142-1 or cross-tying to Unit 2. This was because the condition of the Unit 1 ac power system was not well understood. The EDGs supplied the ESF buses for 29 h. Using the EDG failure to start and run probabilities given in the ASP model for an at-power event, the probability of emergency power failure in the 29 h period because of independent and common-cause effects is estimated to be 1.1×10^{-2} .

⁵ The licensee indicated in the May 19, 1997, phone call that battery lifetime would not be expected to be greater even though the unit was in a shutdown condition. This analysis assumes a 4.5-h battery lifetime, as discussed in the next paragraph. Table 8.3-9 of the Byron *Updated Final Safety Analysis Report* indicates that most battery loads, including the inverters, are assumed to be unavailable after 30 min. This may imply an actual battery life, if instrumentation remains powered, of less than 4 h.

AC RECOV

This branch represents the successful recovery of ac power before the onset of boiling (4.5 h) if both EDGs failed to start and run. Following an estimated 30-min period to stabilize and assess the status of the unit, it was assumed that the licensee would attempt to recover ac power by repairing a failed EDG and by cross-tying the two units. Because the cross-tie procedure can be accomplished from the control room, while any EDG repair would take place at the EDGs, both recoveries were assumed to proceed in parallel.

The probability of failing to recover one of the two EDGs was assumed to be exponentially distributed, with a 4-h median time to repair (see Ref. 7). The probability of failing to cross-tie the Unit 1 and 2 ESF buses was modeled as a time-reliability correlation (TRC) as described in *Human Reliability Analysis* (Ref. 8). Because the sequences of concern in this analysis involve a station blackout, the "recovery with hesitancy" TRC was used in the analysis. The probability distribution for this TRC is lognormal, with an error factor of 6.4. A median response of 10 min was assumed, following the previously described 30-min delay. The potential failure of either cross-tie breaker was also addressed, using a failure-to-operate probability of 3×10^{-3} per breaker (Table 8.2-8, Ref. 9). Using this approach, the estimated probability of failing to recover power to an ESF bus before the onset of boiling (~4.5 h) is

$$\begin{aligned}
 & 5 \times 10^{-1} \text{ (failure to recover one of the two EDGs)} \\
 & \times [2.5 \times 10^{-3} \text{ (operator actions associated with the cross-tie)} \\
 & + 6 \times 10^{-3} \text{ (failure of the cross-tie circuit breakers)}] \\
 & = 4.3 \times 10^{-3} \text{ (failure to recover ac power).}
 \end{aligned}$$

DC CROSS-TIE

The ac power cross-tie procedure (Ref. 2) instructs the operators to cross-tie the dc buses if ac power cannot be recovered to the battery chargers. This branch represents the potential to cross-tie the dc buses between units before battery depletion. This would provide control and instrument power to Unit 1. This analysis assumes the dc cross-tie procedure would be successful if the failure to cross-tie the ac buses was caused by ac breaker problems, but not if the failure to cross-tie the ac buses was caused by the failure of the operators to perform the cross-tie procedure. Using this approach and the failure probabilities estimated in the AC RECOV branch, the probability of failing to cross-tie dc power, given the failure to recover ac power, is estimated to be 0.29.

LONG-TERM
RECOV

This branch represents the long-term recovery of RHR once boiling begins, provided dc power remains available for instrumentation and control. Recovering RHR in this time period would require actions for which procedures do not exist in order to isolate the

RHR system by local manual closure of one of the RHR suction valves prior to overpressurizing the system and to ultimately recover ac power to an ESF and non-ESF bus to allow the use of a charging pump and the PORVs for feed-and-bleed. For the purposes of this analysis, a failure probability of 0.34 was assumed [ASP recovery class R2, see Appendix A to the 1995 ASP status report (Ref. 10)].

Combining these branch probabilities using the event tree model shown in Fig. 1 results in an estimated CCDP for this event of 2.5×10^{-5} .

Analysis Results

The CCDP estimated for this event is 2.5×10^{-5} . The dominant sequence, highlighted in Fig. 1, involves

- the observed LOOP,
- the potential failure of both EDGs to start and run (a station blackout),
- failure to recover ac power prior to battery depletion and the onset of boiling in the region around the core, and
- failure to cross-tie dc power to Unit 2 prior to the onset of boiling.

The other potential core damage sequence shown in Fig. 1, involves

- the observed LOOP,
- the potential failure of both EDGs to start and run (a station blackout),
- failure to recover ac power prior to battery depletion and the onset of boiling in the region around the core,
- dc cross-tie success, and
- failure to prevent overpressurizing the RHR system and recover ac power before core uncover.

The conditional core damage probabilities are shown in Table 1, while Table 2 lists the sequence logic associated with the sequences listed in Table 1. Table 3 provides the definitions and failure probabilities for event tree branch points in Fig. 1.

Other potential sequences leading to core damage, involving the failure to recover RHR once ac power is recovered, are not shown in Fig. 1. As noted in **Modeling Assumptions**, the conditional probability for these sequences is estimated to be below 1.0×10^{-6} .

The uncertainty in this event analysis is dominated by the uncertainty in the potential for overpressurizing the RHR system pressurization once boiling begins and the uncertainty in the probability that ac power would not be recovered through Unit 1–Unit 2 cross-tie following a station blackout.

This event involved water intrusion that degraded insulators on a 4.16 kV bus and resulted in a phase-to-ground fault. This event could have occurred at other proximate times. If it had occurred earlier in the

shutdown, when the amount of decay heat was substantially higher, less time would have been available to recover decay heat removal. This would have resulted in a higher CCDP than estimated herein.

If the event occurred when Unit 1 was at power, the bus fault would have resulted, as a minimum, in an initial loss of power to bus 142. If this occurred, the unit would probably have remained at power, with EDG 1B powering bus 142 loads. If at-power switchyard impacts from the bus fault had been severe enough to have tripped the main transformers, then the fault could have resulted in an at-power LOOP. Because the switchyard response is unknown, the potential for core damage, had the fault occurred at power, was not addressed in this analysis.

Acronyms

ac	alternating current
ASP	accident sequence precursor
CCDP	conditional core damage probability
dc	direct current
EDG	emergency diesel generator
ESF	engineered safety feature
IA	instrument air
kV	kilovolts
LOOP	loss of offsite power
LTOP	low temperature overpressure protection
MWt	megawatts thermal
PORV	power-operated relief valve
RCS	reactor coolant system
RHR	residual heat removal
RTD	resistance temperature detector
SAT	system auxiliary transformer
SG	steam generator
UAT	unit auxiliary transformer

References

1. Licensee Event Report 454/96-007, "Loss of Offsite Power Due to Failure of an Insulator on Phase B of the Unit 1 Station Auxiliary Transformer from Water Intrusion," June 21, 1996.
2. Byron 1 Procedure IBOA ELEC-3, *Loss of 4 kV ESF Bus, Unit 1*, Rev. 54A.
3. Byron Procedure BOP DC-7, *125V DC ESF Bus Crosstie/Restoration*, Rev. 3.
4. Personal communication, N. Hilton (U.S. NRC) and J. Minarick (SAIC), June 30, 1997.

5. Byron 1 procedure IBOA PRI-10, *Loss of RHR Cooling, Unit 1*, Rev. 55.
6. *Evaluation of Potential Severe Accidents During Low Power and Shutdown Operations at Surry, Unit 1*, NUREG/CR-6144, Vol 2, Part 5 (Appendix I), June 1994.
7. *Evaluation of Station Blackout Accidents at Nuclear Power Plants*, NUREG-1032, June 1988.
8. *Human Reliability Analysis*, E. M. Dougherty and J. R. Fragola, John Wiley and Sons, New York, 1988.
9. *Analysis of Core Damage Frequency: Internal Events Methodology*, NUREG/CR-4550, Vol. 1, Rev. 1, January 1990.
10. *Precursors to Potential Severe Core Damage Accidents: 1995, A Status Report*, NUREG/CR-4674, Vol. 23, April 1997.

Fig. 1 Dominant core damage sequence for LER 454/96-007.

INITIATING EVENT - LOOP	EMERGENCY POWER SYSTEM	AC POWER RECOVERED BEFORE CORE BOILING	DC POWER CROSS-TIED	AC POWER RECOVERED BEFORE CORE UNCOVERY	SEQUENCE NO.	END STATE
IE-LOOP	EP	AC RECOV	DC CROSS-TIE	LONG-TERM RECOV		
					1	OK
					2	OK
					3	OK
					4	CD
					5	CD

BYRON 1, ASP PWR B
SHUTDOWN EVENT TREE

Table 1. Sequence Conditional Probabilities for LER No. 454/96-007

Event tree name	Sequence number	Conditional core damage probability (CCDP)	Percent contribution
SHUTDOWN	5	1.4 E-005	55.1
SHUTDOWN	4	1.1 E-005	44.9
Total (all sequences)		2.5 E-005	

Table 2. Sequence Logic for Dominant Sequences for LER No. 454/96-007

Event tree name	Sequence number	Logic
SHUTDOWN	5	EP, AC RECOV, DC CROSS-TIE
SHUTDOWN	4	EP, AC RECOV, /DC CROSS-TIE, LONG-TERM RECOV

Table 3. System Names for LER No. 454/96-007

System name	Description	Failure probability
AC RECOV	Failure to Recover AC Power Before the Onset of Boiling	4.3×10^{-3}
EP	Failure to Recover Emergency Power	1.1×10^{-2}
DC CROSS-TIE	Failure to Cross-Tie DC Buses Before Battery Depletion	2.9×10^{-1}
LONG-TERM RECOV	Failure to Recover RHR After the Onset of Boiling	3.4×10^{-1}

GUIDANCE FOR LICENSEE REVIEW OF PRELIMINARY ASP ANALYSIS

Background

The preliminary precursor analysis of an operational event that occurred at your plant has been provided for your review. This analysis was performed as a part of the NRC's Accident Sequence Precursor (ASP) Program. The ASP Program uses probabilistic risk assessment techniques to provide estimates of operating event significance in terms of the potential for core damage. The types of events evaluated include actual initiating events, such as a loss of off-site power (LOOP) or loss-of-coolant accident (LOCA), degradation of plant conditions, and safety equipment failures or unavailabilities that could increase the probability of core damage from postulated accident sequences. This preliminary analysis was conducted using the information contained in the plant-specific final safety analysis report (FSAR), individual plant examination (IPE), and the licensee event report (LER) for this event.

Modeling Techniques

The models used for the analysis of 1995 and 1996 events were developed by the Idaho National Engineering Laboratory (INEL). The models were developed using the Systems Analysis Programs for Hands-on Integrated Reliability Evaluations (SAPHIRE) software. The models are based on linked fault trees. Four types of initiating events are considered: (1) transients, (2) loss-of-coolant accidents (LOCAs), (3) losses of offsite power (LOOPs), and (4) steam generator tube ruptures (PWR only). Fault trees were developed for each top event on the event trees to a supercomponent level of detail. The only support system currently modeled is the electric power system.

The models may be modified to include additional detail for the systems/components of interest for a particular event. This may include additional equipment or mitigation strategies as outlined in the FSAR or IPE. Probabilities are modified to reflect the particular circumstances of the event being analyzed.

Guidance for Peer Review

Comments regarding the analysis should address:

- Does the "Event Description" section accurately describe the event as it occurred?
- Does the "Additional Event-Related Information" section provide accurate additional information concerning the configuration of the plant and the operation of and procedures associated with relevant systems?
- Does the "Modeling Assumptions" section accurately describe the modeling done for the event? Is the modeling of the event appropriate for the events that occurred or that had the potential to occur under the event conditions? This also includes assumptions regarding the likelihood of equipment recovery.

Appendix H of Reference 1 provides examples of comments and responses for previous ASP analyses.

Criteria for Evaluating Comments

Modifications to the event analysis may be made based on the comments that you provide. Specific documentation will be required to consider modifications to the event analysis. References should be made to portions of the LER, AIT, or other event documentation concerning the sequence of events. System and component capabilities should be supported by references to the FSAR, IPE, plant procedures, or analyses. Comments related to operator response times and capabilities should reference plant procedures, the FSAR, the IPE, or applicable operator response models. Assumptions used in determining failure probabilities should be clearly stated.

Criteria for Evaluating Additional Recovery Measures

Additional systems, equipment, or specific recovery actions may be considered for incorporation into the analysis. However, to assess the viability and effectiveness of the equipment and methods, the appropriate documentation must be included in your response. This includes:

- normal or emergency operating procedures.*
- piping and instrumentation diagrams (P&IDs),*
- electrical one-line diagrams,
- results of thermal-hydraulic analyses, and
- operator training (both procedures and simulator),* etc.

Systems, equipment, or specific recovery actions that were not in place at the time of the event will not be considered. Also, the documentation should address the impact (both positive and negative) of the use of the specific recovery measure on:

- the sequence of events,
- the timing of events,
- the probability of operator error in using the system or equipment, and
- other systems/processes already modeled in the analysis (including operator actions).

For example, Plant A (a PWR) experiences a reactor trip, and during the subsequent recovery, it is discovered that one train of the auxiliary feedwater (AFW) system is unavailable. Absent any further information regarding this event, the ASP Program would analyze it as a reactor trip with one train of AFW unavailable. The AFW modeling would be patterned after information gathered either from the plant FSAR or the IPE. However, if information is received about the use of an additional system (such as a standby steam generator feedwater system) in recovering from this event, the transient would be modeled as a reactor trip with one train of AFW unavailable, but this unavailability would be

* Revision or practices at the time the event occurred.

mitigated by the use of the standby feedwater system. The mitigation effect for the standby feedwater system would be credited in the analysis provided that the following material was available:

- standby feedwater system characteristics are documented in the FSAR or accounted for in the IPE,
- procedures for using the system during recovery existed at the time of the event,
- the plant operators had been trained in the use of the system prior to the event,
- a clear diagram of the system is available (either in the FSAR, IPE, or supplied by the licensee),
- previous analyses have indicated that there would be sufficient time available to implement the procedure successfully under the circumstances of the event under analysis,
- the effects of using the standby feedwater system on the operation and recovery of systems or procedures that are already included in the event modeling. In this case, use of the standby feedwater system may reduce the likelihood of recovering failed AFW equipment or initiating feed-and-bleed due to time and personnel constraints.

Materials Provided for Review

The following materials have been provided in the package to facilitate your review of the preliminary analysis of the operational event.

- The specific LER, augmented inspection team (AIT) report, or other pertinent reports.
- A summary of the calculation results. An event tree with the dominant sequence(s) highlighted. Four tables in the analysis indicate: (1) a summary of the relevant basic events, including modifications to the probabilities to reflect the circumstances of the event, (2) the dominant core damage sequences, (3) the system names for the systems cited in the dominant core damage sequences, and (4) cut sets for the dominant core damage sequences.

Schedule

Please refer to the transmittal letter for schedules and procedures for submitting your comments.

References

1. L. N. Vanden Heuvel et al., Precursors to Potential Severe Core Damage Accidents: 1994, A Status Report, USNRC Report NUREG/CR-4674 (ORNL/NOAC-232) Volumes 21 and 22, Martin Marietta Energy Systems, Inc., Oak Ridge National Laboratory and Science Applications International Corp., December 1995.

Commonwealth Edison Company
Byron Generating Station
4450 North German Church Road
Byron, IL 61010-9794
Tel 815-234-5441

ENCLOSURE 3

ComEd

June 21, 1996

LTR: BYRON 96-0179
FILE: 3.03.0800 (1.10.0101)

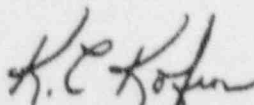
U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555

Dear Sir:

The Enclosed Licensee Event Report from Byron Generating Station is being transmitted to you in accordance with the requirements of 10CFR50.73(a)(2)(iv).

This report is number 96-007; Docket No. 50-454.

Sincerely,



K. L. Kofron
Station Manager
Byron Nuclear Power Station

KLK/WD/js

Enclosure: Licensee Event Report No. 96-007

cc: H. J. Miller, NRC Region III Administrator
NRC Senior Resident Inspector
INPO Record Center
ComEd Distribution List

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A Unicom Company

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS MANDATORY INFORMATION COLLECTION REQUEST: 50.0 HRS. REPORTED LESSONS LEARNED ARE INCORPORATED INTO THE LICENSING PROCESS AND FED BACK TO INDUSTRY. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (7-6 F33), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (156-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503

FACILITY NAME (1) BYRON NUCLEAR POWER STATION	DOCKET NUMBER (2) 05000454	PAGE (3) 1 OF 6
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TITLE (4)
Loss of Offsite Power Due to a Failure of an Insulator on Phase B of the Unit 1 Station Auxiliary Transformer From Water Intrusion

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
05	23	96	96	-- 007 --	00	06	21	96		05000
OPERATING MODE (9) 5			THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §. (Check one or more) (11)							
POWER LEVEL (10) 0			20.2201(b)		20.2203(a)(2)(v)		50.73(a)(2)(i)		50.73(a)(2)(viii)	
			20.2203(a)(1)		20.2203(a)(3)(i)		50.73(a)(2)(ii)		50.73(a)(2)(x)	
			20.2203(a)(2)(i)		20.2203(a)(3)(ii)		50.73(a)(2)(iii)		73.71	
			20.2203(a)(2)(ii)		20.2203(a)(4)		X 50.73(a)(2)(iv)		OTHER	
			20.2203(a)(2)(iii)		50.36(c)(1)		50.73(a)(2)(v)		Specify in Abstract below or in NRC Form 366A	
			20.2203(a)(2)(iv)		50.36(c)(2)		50.73(a)(2)(vii)			

LICENSEE CONTACT FOR THIS LER (12)

NAME Ray Choinard, Root Cause Expert	TELEPHONE NUMBER (Include Area Code) 815-234-5441 X2041
--	---

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
XP E4	EB	Electrical Insulator	H. K. Porter						
XI E2	IG	SR/IR Detector	Westinghouse	Y					

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE).	X	NO	EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
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ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On 5/23/96, Unit 1 experienced a loss of Offsite Power (LOOP) for more that fifteen minutes. As a result of the LOOP, the Station Air Compressors and non-essential service water pumps were lost. This lead to a decision to manually trip Unit 2.

The LOOP resulted from a fault on Station Auxiliary Transformer (SAT) 142-2. The fault was caused by a failed insulator on the B phase on the non-segregated bus duct. The insulator failed due to water intrusion into the bus duct. Water leaked into the bus duct because of caulk that was leaking and a poor seal between the retaining bolts for the insulator and the bus duct.

The bus duct was repaired, the other bus ducts were inspected, and changes to the preventative maintenance of the non-segregated bus ducts are planned.

After Unit 2 was manually tripped, Source Range Detector, N31, failed to energize. The cause was a failed detector. The detector was replaced.

There was a previous event of water intrusion into the non-segregated bus ducts at Byron Station prior to 1984 (before fuel load).

These events are reportable in accordance with 10CFR50.73(a)(2)(iv) as any event or condition that resulted in a manual or automatic actuation of any engineered safety feature (ESF), including the reactor protection system (RPS).

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)		DOCKET	LER NUMBER (6)			PAGE (3)
BYRON NUCLEAR POWER STATION		05000454	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	2 OF 6
			96	-- 007	-- 00	

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

A. PLANT CONDITIONS PRIOR TO EVENT:

Event Date/Time 05-23-96 / 0804

Unit 1 Mode 5 - Hot Shutdown Rx Power 0% RCS [AB] Temperature/Pressure 85/350

Unit 2 Mode 1 - Power Operations Rx Power 100% RCS [AB] Temperature/Pressure NOT/NOP

B. DESCRIPTION OF EVENT:

Prior to this event, the Unit 2 Station Air Compressor (SAC)[LF] and the OC Non-essential Service Water (WS)[KG] were Out-of-Service. By not having these available, a manual trip of Unit 2 was required. This increased the severity of this event.

Unit 1 Event

On 5/23/96 at 08:04, Unit 1 Station Auxiliary Transformers (SAT's) [EB] isolated due to a phase A to phase B current differential relay operation. This de-energized all 4.16 kV and 6.9 kV buses on Unit 1.

At 08:22, an Usual Event was declared due to the loss of offsite power for greater than 15 minutes.

At 08:29, shift personnel notified the State of Illinois about the event.

At 08:36, shift personnel made notification to the NRC via the ENS about the event.

Both the 1A and 1B Diesel Generators (DG) [EK] auto started and loaded on to ESF busses 141 and 142. The non-ESF busses, 143 and 144, both remained de-energized. Since the OA and OB Non-essential Water (WS) [KG] pumps and Unit 1 and Unit 0 Station Air Compressors (SACs) [LD] were powered from 143/144, they tripped when power was lost.

Unit 2 Event

Without the WS pumps (Non-essential cooling water is a unit common system), Unit 2 did not have cooling water to many loads including Generator Auxiliaries, SAC's, and Condensate/Condensate Booster pumps. Because there was no cooling to secondary systems or station air, the Unit 2 reactor was manually tripped at approximately 08:06.

Unit 2 responded normally from a manual Reactor trip except for the following:

- Source Range Detector [IG], N-31 failed to energize.
- The 2A Steam Generator Power Operated Relief Valve (PORV) [SB] failed to close in manual mode, and
- Process radiation monitor [IL], 2PRO9J, "Component Cooling Water Heat Exchanger 2 Outlet Monitor Skid," experienced a loss of communication with the main console (RM-11) in the control room.

Unit 2 remained stable in Mode 3 until the decision was made to cool down to Mode 5 for repair of 2RC8075D, "2D RC Loop Cold Leg RTD Manifold Outlet Isolation Valve." This valve was found leaking during the post trip containment walk down.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION					
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TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

B. DESCRIPTION OF EVENT (cont.)

All rods inserted into the core. (This statement satisfies ComEd's commitment to NRC Bulletin 96-01 for reporting post trip rod insertion.)

These events are reportable in accordance with 10CFR50.73(a)(2)(iv) as any event or condition that resulted in a manual or automatic actuation of any engineered safety feature (ESF), including the reactor protection system (RPS).

C. CAUSE OF EVENT:

Unit 1 Event

Switchyard breakers OCB 5-6 and ACB 6-7 feed the Unit 1 SAT. The Unit 1 SAT consists of two transformers numbered 142-1 and 142-2. Each provides a 4.16 kV and 6.9 kV feed to Unit 1. These feeds are further subdivided inside the Auxiliary Building (AB) into two 4.16 kV buses (one Safety Related and one Non-Safety Related) and two non-safety related 6.9 kV buses. The buses coming from each SAT into the AB are run in two, non-segregated bus ducts, one for the 4.16 kV and one for the 6.9 kV. The three phases of 4.16 kV are all in the same duct (non-segregated), separated from each other by about four inches. They are supported from the top of the bus duct by insulators. The 6.9 kV bus design is similar.

The Unit 1 SAT 142-2 underwent a phase to ground fault on a phase B insulator. The location of the failed insulator was about half-way between the SAT and the AB. Upon flashing, the arc continued down the bus bar, increasing in width until it involved the other two phases.

The specific evidence that supports this conclusion was the insulator damage and water found still dripping through the bus duct onto the damaged insulator several hours after a rain shower. The initial point of arcing was at this insulator and subsequent splatter of bus material could be followed from this point towards the AB. As the arc heated the air and water in the duct, the duct pressurized. This caused the bottom duct bus panels to bulge until the pressure was relieved through small vent holes in the panels.

The primary reason for the event was chronic water leakage through the insulator mounting holes. This led to the failure of the phase B insulator. The water caused the degradation of the insulator metal inserts and insulator material between these inserts. Eventually the bus flashed to ground through the degraded insulator and initiated the event.

The cause of the water leakage has two components:

- 1) There is a weld axially down the center of the top of the duct that the center insulator mounting bolts must straddle. This will not allow the channel-to-duct seal to be compressed properly.
- 2) The caulk put on the channel-to-duct interface to supplement sealing this barrier is very thin in the area of leakage on this insulator and was not sealed completely (see Figure 1).

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TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

C. CAUSE OF EVENT (cont.)

These two factors allowed water to seep into the insulator center and caused the insulator inserts to corrode and eventually fail (see Figure 2).

Unit 2 Event

Source Range Detector, N31, failed to energize because of a failed detector.

D. SAFETY ANALYSIS:

Unit 1 Event

Unit 1 ESF equipment functioned as designed. The Auxiliary Power (AP)[EA] system isolated the fault immediately to prevent further damage to equipment/components. With Unit 1 in Mode 5, all Unit 1 4.16 kV and 6.9 kV buses were powered from SAT 142-1 and 142-2. Per design, only the ESF (bus 141 and 142) buses automatically re-energized from 1A and 1B DGs. With both ESF buses energized the reactor core cooling was then re-established by starting the 1A RH pump. The 1B RH train was also available.

Unit 2 Event

U-2 was manually tripped to prevent damage to secondary equipment per procedure. An automatic trip would have occurred eventually due to loss of 1A that would have caused the Feedwater regulating valves to fail closed. Unit 2 equipment/components functioned properly except for:

Source Range Detector N-31 [IG] failed to energized. This was not significant since N-32 was available and energized.

The 2A Steam Generator PORV [SB] failed to close in manual mode using the controller. This was not significant because it was isolated by taking the control switch to close. And the other PORVs were available for core heat removal.

Process radiation monitor 2PRO9J [IL] experienced a loss of communication with the RM-11. This was not significant because two other monitors were available to monitor component cooling.

All unit buses remained energized by the Unit 2 SAT's (242-1 & 242-2). During the recovery of Unit 2, there was damage to the 2C Feedwater [SJ] pump recirculation line due to a water hammer event. The cause of this event was investigated under a separate report (PIR 455-200-96-0003).

E. CORRECTIVE ACTIONS:

Unit 1 Event

On the Unit 1 non-segregated bus duct (SAT 142-2), the following were completed or are planned:

All the insulator inserts on the Unit 1, 142-2, bus duct were inspected for rust and signs of water leakage. Insulators with rust were removed and cleaned or replaced. All insulators were cleaned. The damaged insulator was replaced.

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E. CORRECTIVE ACTIONS (cont.)

The tightness of the bolts holding the insulator footings to the channel steel was verified to be adequate.

The inside of the bus duct was cleaned.

The damaged cross braces were repaired.

All the channel steel was recaulked.

The rubber seals on the channel steel that was supporting the insulator that failed were replaced with two rubber seals placed on top of each other. The weld was ground down.

The five year preventative maintenance for the bus was done. This was last done in September of 1991.

The Unit 1, 4.16kV (SAT 142-1) and the 6.9kV (SAT 142-1 and SAT 142-2), non-segregated bus ducts were visually inspected to evaluate the condition of the caulking. Areas that had insufficient or lacked caulking were recaulked.

The Unit 2, 4.16kV and 6.9kV, non-segregated bus ducts (SAT 242-1 and SAT 242-2) were visually inspected to evaluate the condition of the caulking. Areas that had insufficient or lacking caulking were recaulked. Only accessible areas were inspected.

The lessons learned from this event will be shared with other ComEd stations. NTS item 454-240-96-0054-08 will track this action.

After final repairs are completed on the bus duct for SAT 142-2, the full list of repairs will be reviewed for implementation on the other non-segregated bus ducts and for incorporation into the PM program. NTS item 454-240-96-0054-11 will track this action.

Unit 2 Event

The failed Source Range Detector was replaced and calibrated.

The M/A (Manual/Auto) station for the 2A Steam Generator PORV was inspected under Work Request 960051435 and no problems were found. The valve was also stroke tested with no problems. No further actions are planned.

Radiation monitor 2PRO9J loss of communication cleared at about 1203 that day and no work was done on the monitor. The cause of the communication problem is unknown.

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TEXT (If more space is required, use additional copies of NRC Form 366A, (17))

F. RECURRING EVENTS SEARCH AND ANALYSIS:

SOER 90-1, "GROUND FAULTS ON AC ELECTRICAL DISTRIBUTION SYSTEMS."

This SOER discusses six events that occurred in the industry involving faults on AC electrical systems. The SOER contains recommendations for inspections of electrical busses. Byron Station committed to inspecting the non-segregated bus ducts. The inspections included insulators, fire barriers, wall penetrations, grounding systems, drains, and bolted connections. The station did not include inspection of the caulking on the channel steel. Additional preventative maintenance activities will be done as a result of this event.

A search on ETS of previous Byron events over the last five years found no events involving water intrusion into non-segregated bus ducts. The keywords used were "bus and duct." However, during a bus inspection prior to 1984 (before fuel load), following a trip of a Unit 2 SAT on the high voltage side. Water leakage was found and an attempt to caulk the channel steel to duct interface was done. The significance of the caulked joint was stressed with workers, prior to re-application for this event.

G. COMPONENT FAILURE DATA:

<u>MANUFACTURER</u>	<u>NOMENCLATURE</u>	<u>MODEL NUMBER</u>	<u>MFG PART NUMBER</u>
H.K. Porter	Insulator	A-30	617A
IST	Excure Detector	N//A	WL-23706