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U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

Resolution of Generic Safety Issues: Issue 47: The Loss of Offsite Power (NUREG-0933, Main Report with Supplements 1–34)

DESCRIPTION

Historical Background

On April 7, 1980, Arkansas Nuclear One (ANO) Units 1 and 2 experienced a significant event resulting from a loss of offsite power. Although both units were safely shut down, the analysis and evaluation of the event identified some design and procedural deficiencies. As a result of their investigation of this (event, AEOD published a report[330] which included a set of recommendations based on their findings.

Safety Significance

The offsite power system of a nuclear power plant provides the preferred source of electrical power to all the station auxiliaries. Loss of the offsite source results in a plant upset condition (usually a reactor trip) and the start of the backup power sources. Correct plant response would not result in risk to the public; however, there is a large amount of equipment which must function to mitigate such an event. Overall plant response to such an event may indicate plant specific and/or generic problems that could lead to core melt.

Possible Solution

AEOD investigated the ANO plant response and noted some problems. Based on their review and findings, they made the following recommendations:

(1) The design arrangement and operation of the bus tie autotransformer should be considered and reviewed by the licensee and NRC to determine possible failure modes and minimize the probability of losing offsite power. A single failure (loss of bus tie autotransformer) in the offsite power supply system should not result in a two unit upset and a need for the onsite emergency power system. In this regard, the implementation of GDC-17 should be reevaluated. In the past, GDC-17 has not been implemented to require the offsite power source to meet the single failure criterion.

(2) An IE Information Notice has been issued concerning the loss of the emergency feedwater system due to simultaneous alignment to the Startup and Blowdown Demineralizer System and the condensate storage tank. Although not included in this notice, each licensee should be requested to describe the modes of operation of the emergency feedwater system and other safety-related systems for non-emergency conditions, including operation at low reactor power and refueling. The acceptability of simultaneous alignment below some specified power level for these systems (e.g., 5% full power) should be evaluated by NRR.

(3) The safety implications of overfeeding and overcooling the pressurizer with the HPI for B&W plants should be evaluated. Sustained operation of the HPI results in limited pressure control and possible loss of the pressurizer steam bubble. There is also an increased probability of a stuck open relief valve. In addition, the system is subjected to an additional thermal stress cycle. The licensees should be advised against sustained operation of the HPI system after the steam pressure has been recovered and adequate subcooling exists.

(4) Licensees should be advised of the failure of the high pressure injection system isolation valve due to a stuck

handwheel engage lever, particularly if this problem has been experienced elsewhere. It should be emphasized that all safety-related valves should be tested from the control room after the valves have been manually operated (e.g., during maintenance).

(5) Action should be initiated to develop recordkeeping requirements or perhaps a Regulatory Guide to address the need for adequate and accurate operator log entries during normal and transient operation, especially when the process computer is unavailable. This information is required for post-event analysis.

(6) Licensees should be advised of the need to ensure that plant response data and information developed immediately prior to and during a transient is appropriately retained. The licensee should ensure that any selector or mode switch, if provided for the process or trend computers, is always in the position which ensures that the computer is available during a loss-of-offsite power event.

(7) There have been repeated problems with the ANO Unit 2 turbine-driven emergency feedwater train which have rendered it inoperable.[330] These resulted in only one full-capacity, motor-driven emergency feedwater train available to provide the safety function of providing emergency feedwater to both steam generators. It is important to ensure the reliability of the motor-driven emergency feedwater train until the problems with the turbine-driven train are resolved. Resolution of the problems with the turbine-driven train should be expedited and, until full resolution has been achieved, interim licensee actions should be implemented to ensure high reliability of the motor-driven emergency feedwater train.

(8) Prompt and careful consideration should be given by NRR to the development of suitable criteria to be used by reactor operators to determine and thereby claim that natural circulation has been achieved. This is a potentially serious area for misinterpretation or misunderstanding during an event wherein it may be important to quickly communicate the plant status to the NRC in unambiguous terms. Operator academic instructions and training progrms should specifically address these criteria and assure that the operators have a complete understanding regarding how natural circulation can be determined.

NRC addressed[331] all of the AEOD recommendations specifically as follows:

(1) PBS concluded that no further action is required on this recommendation since related requirements are presently being implemented on all operating plants through MPAs B-48 and B-23 and case work reviews through SRP Section 8.2, Revision 2 review procedures and BTP PSB-1. Furthermore, the overall issue of loss of electric power (both offsite and onsite) is being addressed by USI A-44.

(2) OIE issued Information Notice 80-23 and NRR is pursuing this under resolution of TMI Action Plan Item II.E.1.1, "Auxiliary Feedwater System Evaluation," which is being implemented as part of NUREG-0737.[98]

(3)NRR addressed this as three separate recommendations:

(a) **Safety Implications of Overfeeding the Pressurizer with High Pressure Injection**

NRR concluded (although from an operational standpoint this is not desired) that there are no direct safety implications of overfeeding and overcooling the pressurizer with HPI.

(B) **Advise Licensee Against Sustained HPI Operation After System Pressure Recovery and Existence of Adequate Subcooling.**

NRR concluded that sufficient guidance has been provided to all licensees by Inspection and Enforcement Bulletin No. 79-06A and by vendor-supplied operator guidelines.

(c) **Need for HPI to Recover System Pressure and Pressurizer Level in a B&W NSSS After Reactor Trip**

The actions presently in place to address this recommendation are documented in TMI Action Plan Item II.E.5 "Design Sensitivity of B&W Reactors."

(4) Regarding the stuck handwheel engage-lever problem, NRR concluded that this is not a generic problem and further action is not warranted at this time. Regarding the testing of valves, NRR concluded that this recommendation is already incorporated as TMI Action Plan Item I.C.6, "Procedures for Verification of Correct Performance of Operating Activities" which is mandated by NUREG-0737.[98]

(5) NRR concluded that the Technical Support Center (and its data acquisition system) requirements[376] will also provide the desired result; i.e., information for post-event analysis. Furthermore, NRR stated that the proposed revision to Regulatory Guide 1.33, "Quality Assurance Program Requirements," will address the aspect of upgraded log-keeping. As a result, they concluded that this concern was sufficiently addressed.

(6) Similar to the above recommendation 5, NRR concluded that the Technical Support Center data acquisition system[376] addresses this concern.

(7) This recommendation is not generic and applies only to ANO. NRR concluded that the experience to date demonstrates sufficient availability of the ANO turbine-driven EFW pump and that additional interim licensee actions by ANO to ensure high reliability of the motor-driven EFW pump were unwarranted.

(8) NRR concluded that this recommendation is adequately addressed by other actions (TMI Action Plan Item I.C.1, "Short-Term, Accident Analysis and Procedures Revision," and plant operating procedures which address inadequate core cooling) and that additional requirements beyond the indicated actions are unnecessary.

CONCLUSION

Based on the NRR report,[331] we conclude that the AEOD recommendations are included in other issues or are RESOLVED.

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Resolution of Generic Safety Issues: Issue 107: Main Transformer Failures (Rev. 3) (NUREG-0933, Main Report with Supplements 1–34)

DESCRIPTION

Historical Background

This issue was identified in a DL/NRR memorandum[1183] which called for an assessment of the high failure frequency of main transformers and the resultant safety implications. Concern for this issue arose when the North Anna Power Station had seven main transformer failures in 26 months; five of these resulted in reactor trips. Of the seven failures, three included rupture of a transformer tank that resulted in two fires. One of the fires spread beyond the transformer bay to the turbine bay. In a report[1184] prepared for the NRC by LLNL, it was concluded that there was a possibility of generic implications arising out of the plant-specific failures reported for the North Anna units.

The potential generic concerns identified in the LLNL report[1184] included the fire protection system, overhead conductor/buses, cable trays, storage of flammable materials, and oil-filled transformers in general. In addition, certain secondary aspects of the transformer failures were identified which included cascading effects, extensive electrical/mechanical damage, and missiles/explosions, although the LLNL report noted that these latter items appeared to be either indirectly or remotely related to specific safety-significant concerns. Existing NRC regulations and guidance pertaining to fire protection and some of the generic concerns raised in the LLNL report[1184] are embodied in 10 CFR 50 Appendix R, the SRP,[11] and Regulatory Guide 1.120.[1185] In this analysis, the need for additional actions by the licensees to prevent main transformer failures and to reduce the resultant risk were evaluated.

Safety Significance

Safety-related loads in nuclear power plants are supplied from buses that can be supplied from any one of the following sources: (1) the unit auxiliary (main) transformer; (2) the startup transformer (or reserve auxiliary transformer); or (3) the emergency onsite power supply (i.e., diesel generators). A main transformer failure will result in a loss of load or unbalanced load on the main generator. This would lead to turbine/generator trip and power would not be available to the unit transformers for the station power; however, station power can be obtained from the grid through the startup transformer or from emergency onsite power sources. Switchyards have redundant systems to provide sufficient relaying and circuit breakers so a transformer failure is not expected to cause a loss of offsite power.

Other generic concerns associated with this issue included: (1) oil from a ruptured transformer could float on the water delivered to extinguish the fire by the fire protection system such that the fire will move in the direction of drainage; (2) the fire may propagate to overhead cables and buses and create the need for access to adjacent locations (such as building roofs) by fire-fighting crews.

Possible Solutions

Resolution of this issue could involve the following actions:

(1) Evaluation of main transformer design and arrangements by licensees to ensure that the supply of offsite power is protected against transformer fires and smoke. Design requirements should be established for routing and separation of offsite power source feeds to protect against power loss due to a transformer fire.

(2) Review of fire protection system features for the main transformers for adequacy and revision, as necessary, to ensure that a potential fire is prevented from spreading to other plant areas. The review should address the deluge system, drainage system, fire barriers, and fire-fighting equipment and procedures.

(3) Review of maintenance and operating procedures for the main transformers for adequacy and revision, as necessary.

(4) Modification of drainage systems, if necessary, to provide drains for each transformer so that liquids flow away from the turbine building, power lines, and safety-related cables to the reactor and related safety equipment. Modifications could include adding drains, building dikes, and sloping the transformer yard away from buildings and other transformers.

(5) Modification of fire-fighting equipment and procedures, if necessary. This could include longer hoses, increased ease of access to building roofs, mobility of fire-fighting equipment, and training for personnel.

(6) Relocation of power lines to the safety-related buses, if necessary, so that they would not be affected by a fire in the transformer bay.

PRIORITY DETERMINATION

To establish the priority of this issue, the potential reduction in core-melt frequency as a result of improved main transformer reliability due to implementation of the proposed solutions was quantified. It was believed that improved reliability of main transformers would reduce the frequency of transients induced due to main transformer failures, thus leading to enhanced plant safety.

Frequency Estimate

In the representative plant PRAs (Oconee-3 for PWRs and Grand Gulf-1 for BWRs), main transformer failures are integrated into a category of transients that result from loss of network load. The affected PRA parameters are transients other than loss of offsite power requiring or resulting in a reactor shutdown, i.e. T_2 (frequency of 3/RY) and T_{23} (frequency of 7/RY) for Oconee-3 and Grand Gulf-1, respectively. It was assumed that implementation of the possible solutions would enhance the reliability of main transformers and thus reduce the frequency of the resultant transients.

Data in NUREG/CR-3862[1186] on a specific transient category, characterized as a loss of incoming power to a plant as a result of onsite failure (such as main transformer failure), suggest that the transient frequency associated with this category is 0.02 event/RY. In addition, the IEEE reliability data for liquid-filled transformers (347 to 550 KVA) at nuclear power plants indicate that the main transformer failure rate due to all causes was 2.67/million-hours. This corresponded to an annual frequency of 0.023 failure/year for main power generator or unit transformers. This value was used as the base case for the failure frequency of main transformers. The second aspect of the main transformer failure, the risk from resulting fire, was determined to be insignificant and was not analyzed further. This conclusion was based on the findings of the Oconee-3 PRA which included the analysis of fires and their potential for causing failures of redundant safety-related components. Also, no particular sensitivity to main transformer fires was identified in NUREG/CR-5088.[1211]

It was assumed that implementation of the possible solutions (i.e., no design improvements to the transformer but improved maintenance and mitigative designs/procedures) would increase the reliability of main transformers by 50%. Therefore, the adjusted case main transformer failure frequency was estimated to be 0.01 event/RY. In addition, the adjusted case frequencies of the resultant transients (T_2 and T_{23}) were estimated as

follows:

T_2 = (3 - 0.01)/RY
= 2.99/RY
T_{23}= (7 - 0.01)/RY
= 6.99/RY
Incorporating these values in the Oconee-3 and Grand Gulf -1 PRAs provide reductions in core-melt frequency estimates of 1.4×10^{-7}/RY for PWRs and 3.6×10^{-8}/RY for BWRs.

Consequence Estimate

This issue was assumed to be pertinent to all LWRs and thus had an affected population of 90 PWRs and 44 BWRs with average remaining lives of 28.8 years and 27.4 years, respectively. Based on the Oconee-3 and Grand Gulf-1 PRAs, the associated public risk reduction was estimated to be 0.38 man-rem/RY and 0.25 man-rem/RY for PWRs and BWRs, respectively. Thus, the average public risk reduction associated with this issue was 9.6 man-rem/plant.

Cost Estimate

Industry Cost: Implementation of the possible solutions at the affected plants would require review of existing systems and procedures and hardware changes. It was estimated that the review of the existing systems and procedures would require 15 man-weeks/plant at $2,270/man-week. These efforts would include evaluation of the fire protection systems, review of protective circuitry, review of operating and maintenance procedures, revision of operating and maintenance procedures, and revision of staff training. It was also assumed that, as a result of these reviews, about 10% of all affected plants would require hardware changes, modifications to fire protection systems, and re-routing of cables around the main transformer areas. It was estimated that 9 man-weeks would be required to prepare the design modifications and acceptance testing plan, install and test hardware changes, and revise procedures. Hardware and labor were estimated to cost $48,000/plant to provide the following: additional drains, gravel, and concrete to slope the area around the transformers and construct dikes; additional power lines to route power to the buildings; additional breakers to protect equipment connected to the auxiliary transformers; and longer fire hoses. The cost was itemized as follows:

Dike (250 ft. long, 4 ft. high) =$ 3,750

Concrete and Gravel = 15,800

Power lines (1,000 ft) = 5,000

Breakers (2 at $2500 each) = 5,000

Fire Hose/Storage Cabinet (110 ft) = 500

Note: An escalation factor of 1.8 was used by PNL to convert 1982 dollar values to 1988. Therefore, the cost to implement the possible solutions at 90% of the plants was about $30,000/ plant; for the remaining 10%, the cost was estimated to be $100,000/plant. The average cost for the affected population was approximately $40,800/plant.

For the affected plants, periodic review of main transformer procedures, operations, and maintenance was estimated to require 0.2 man-week/RY. At a cost of $2,270/man-week, this amounted to $450/RY. In addition, those plants requiring hardware modifications (10% of affected plants as discussed above) require 1 man-week/RY (or $2,270/RY) for periodic maintenance/inspection of drains and new diked areas, removal of trash from drains, etc. Plant maintenance and operation costs are recurring costs and were adjusted for present worth at a 5% discount rate over the 28.3-year average remaining plant life for the 134 affected plants. This resulted in an average plant cost (present worth) of $11,200/plant.

It was believed that improvements to the reliability of main transformers and improvements to fire protection systems could potentially result in: (1) avoided costs of replacing a transformer damaged by fire (3 out of 14 transformer failures resulted in fire, or 0.002 main transformer failure/RY); and (2) avoided replacement power costs associated with reducing the number of reactor trips caused by main transformer failures.

NRC Cost: NRC costs consisted of initial regulatory development and the resources required in support of the regulatory implementation. The initial regulatory development cost could involve the issuance of a generic letter or bulletin to the licensees, review of licensee responses, other related activities (i.e., revised design guidance, assessment of differences in plant design related to transformers, development of potential implementation measures), and the required technical, legal, and administrative staff labor. This portion of resource requirements was estimated to require 40 man-weeks ($90,000) in addition to potential outside contractor support (estimated to cost $50,000) for a total of approximately $140,000. Averaging this over the 134 affected plants resulted in an approximate NRC cost of $1,000/plant.

The implementation resource requirements consist of NRC labor to review utility plans to comply with revised guidance and additional inspection and monitoring of transformer maintenance/testing programs during the routine NRC plant inspections. This was estimated to require $4.1M over the life of all affected plants. These costs are also recurring costs and when adjusted for present worth, as indicated above, resulted in an average NRC cost (present worth) of $17,000/plant.

Total Cost: The total industry and NRC cost associated with the possible solution was estimated to be $70,000/plant.

Value/Impact Assessment

Based on a potential public risk reduction of 9.6 man-rem/reactor and an estimated cost of $70,000/reactor for a possible solution, the value/impact score was given by:

$$S = \frac{9.6\text{man} - \text{rem} / \text{reactor}}{\$0.07\text{M} / \text{reactor}}$$
$$= 137\text{man} - \text{rem} / \$\text{M}$$

Other Considerations

(1) Implementation of the possible solutions was assumed not to involve any labor in radiation zones because the main transformers are not located in a building in which radioactive materials are used or stored and thus the radiation dose rates are zero.

(2) The core-melt frequency reductions of 1.4×10^{-7}/RY for PWRs and 3.6×10^{-8} /RY for BWRs results in ORE avoidance associated with core-melt cleanup operations of 20,000 man-rem/core-melt.[64] The accident avoidance over the remaining plant life was [(28.8)(90)(1.4×10^{-7}/RY) + (27.4)(44)(3.6×10^{-8}/RY)] (20,000)/134 or 0.06 man-rem/plant. The present worth cost of a core-melt accident was estimated to be $1.65 billion considering cleanup and replacement power cost over a ten-year period.[64] The present worth of accident avoidance at each plant was estimated to be [(28.8)(1.4×10^{-7}/RY)(90) + (27.4)(3.6×10^{-8} /RY)(44)] ($1,650M)/134 or $5,000.

(3) Existing designs of operating nuclear power plants incorporate various independent means of supplying loads so that main transformer failures would not cause a total loss of offsite power. In addition, the promulgation of the station blackout rule (10 CFR 50.63) should further reduce the risk from loss of AC power from that considered in the Oconee-3 and Grand Gulf-1 PRAs.

(4) It was believed that implementation of the possible solutions could be accomplished during normal plant

outages and would not require design modifications or work in radiation zones. The relatively high failure frequency of the main transformers at the North Anna plant highlighted a possible need for plant-specific evaluations by some licensees to review their main transformers and to implement an appropriate combination of the alternatives proposed in order to enhance safety.

CONCLUSION

Based on the above value/impact score, the issue was on the borderline between a low and medium priority for existing plants. However, it was believed that the risk estimates were high (because the effect of the station blackout rule was not included in the Oconee-3 and Grand Gulf -1 PRAs). Therefore, the issue was given a low priority ranking (see Appendix C) for existing plants.

Following a periodic review of low priority issues, NRR provided new information[1749] on transformer failures that required a reevaluation of the issue. Further prioritization, using the conversion factor of $2,000/man-rem approved[1689] by the Commission in September 1995, resulted in an impact/value ratio (R) of $11,565/man-rem which placed the issue in the DROP category.[1750]

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