UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

SUPPORTING AMENDMENT NO. 42 TO FACILITY LICENSE NO. DPR-35

BOSTON EDISON COMPANY

PILGRIM NUCLEAR POWER STATION

DOCKET NO. 50-293

A. Pilgrim Nuclear Power Station, Unit No. 1 Reload 4 Application

1.0 Introduction

Boston Edison Co. (the licensee) has proposed changes to the Technical Specifications of the Pilgrim Nuclear Power Station, Unit No. 1 (Pilgrim 1).(1) The proposed changes relate to the replacement of 184 fuel assemblies, constituting refueling of the core for cycle 5 operation at power levels up to 1998 MWe (100% power).

In support of the reload application, the licensee has provided the GE BWR Reload Licensing Submittal for Reload 4(2) and a set of proposed Technical Specification changes.(3) This reload involves loading of new GE 8x8R fuel plus GE 8x8 fuel irradiated in previous cycles. The description of the nuclear and mechanical design of the 8x8 and 8x8R fuel is contained in GE's licensing topical report for reloads(4) and a more recent letter report.(5) Reference 4 also contains a complete set of topical reports which describe GE's analytical methods for nuclear, thermal-hydraulic, transient and accident calculations, and information regarding the applicability of these methods to cores containing 8x8 and 8x8R fuel.

Because of our review of a large number of generic considerations related to use of 8x8R fuel in mixed loadings with 8x8 and 7x7 fuel, and on the basis of the evaluation presented in Reference 4, only a limited number of additional areas of review have been included in this safety evaluation report. Evaluations not specifically covered in this report are addressed in Referance 4.

2.0 Evaluation

2.1 Nuclear Characteristics

For cycle 5 operation of Pilgrim 1, 120 fresh 8x8R bundles of type P8DRB265L and 64 fresh bundles of type P8DRB282 will be loaded into the core.(2) The remainder of the 580 fuel bundles will be 8x8 fuel bundles exposed during previous cycles.

8005230593

Based upon the data provided in Reference 2, both the control rod system and the standby liquid control system will have acceptable shutdown capability during Cycle 5.

2.2 Thermal-Hydraulics

2.2.1 Fuel Cladding Integrity Safety Limit

As stated in Reference 4, the minimum critical power ratio (MCPR) which may be allowed to result from core-wide or localized transients is 1.07. This limit has been imposed to assure that during transients 99.9% of the fuel rods will avoid transition boiling.

The safety limit MCPR for Pilgrim 1 is being raised from 1.06 to 1.07 because the distribution of fuel rod power within the 8x8R fuel bundles is different from that of the 8x8 fuel. The reason for the difference is the presence of two rather than one water rod in 8x8R fuel. The issue has been addressed in Reference 4 and the 1.07 limit has been found acceptable for BWRs with uncertainties in flux monitoring and operational parameters no greater than those listed in Table 5-1 of Reference 4, for which the CPR distribution is within the bounds of Figures 5.2 and 5.2a of Reference 4. It has been shown in Section 5 of Reference 4 that these conditions are met for Pilgrim 1.

2.2.2 Operating Limit MCPR

Various transients could reduce the MCPR below the intended safety limit MCPR during Cycle 5 operation. The most limiting of these operational transients have been analyzed by the licensee to determine which event could potentially induce the largest reduction in the initial critical power ratio (ΔCPR).

The transients evaluated were the limiting pressure and power increase transient (in this case, the load rejection transient without turbine bypass to the main condensor), the limiting coolant temperature decrease transient (loss of feedwater heater), the feedwater controller failure transient, and the control rod withdrawal error transient. Initial conditions and transient input parameters as specified in Sections 6 and 7 of Reference 2 were assumed.

The calculated systems responses and ΔCPRs for the above listed operational transients and conditions have been analyzed by the licensee. Results were as follows:

Transient	Calculated ΔCPR By Fuel Type 8x8	P8x8R
Load Rejection w/o Bypass	.15	.16
Loss of Feedwater Heater	.15	.15
Feedwater Controller Failure	.12	.12
Rod Withdrawal Error	.17	.19

The transient analyses described above were performed with the REDY code.(6) A new improved code, ODYN,(7) has been developed by GE. The ODYN code, which uses a more physically correct model of the plant, generally predicts smaller ΔCPRs than the REDY code when the transient under study is fairly severe. However, as transient severity is lessened, ODYN predicts a greater ΔCPR than REDY (Reference 8, p. 1). Both codes are run with conservative input values, but ODYN is a better predictor of plant behavior once these input values are specified.(9)

GE has stated(8) that REDY can still be used because the limiting transient has a ΔCPR sufficiently large to be above the region where REDY is non-conservative with respect to ODYN. We have proceeded on this basis in approving reloads thus far. However, the transient analyses performed for Pilgrim 1 Cycle 5 predict ΔCPRs is a range where GE's assertion(8) is no longer valid for those transients which involve a turbine trip or fast closure of the turbine throttle valves. The limited data available to us clearly indicate that calculations which include axial effects and detailed steam line modeling predict more severe results than do point kinetics REDY calculations.

Therefore, unless more justification for the REDY-based calculations is forthcoming, the transient analysis results must be conservatively adjusted to account for this effect. The analyses affected are the load rejection without bypass transient and the feedwater controller failure transient. The loss of feedwater heater transient is much slower, and therefore should be well simulated by point kinetics calculations. Moreover, the loss of a feedwater heater does not lead to a turbine trip and thus there is no significant excitation of acoustic resonances in the steam line. The remaining analysis (rod withdrawal error) is not calculated with REDY and therefore is not affected.

Thus, the load rejection transient and the feedwater controller failure transient (which involves a turbine trip) must have their analyses adjusted to account for defects in the steam line and core axial response modeling. Comparisons of the REDY and ODYN calculations presented on p. 12 of Reference 8 have enabled us to estimate a nonconservative trend for the REDY-calculated ΔCPR values. The estimated degree of non-conservatism is given by the following formula:

$$\text{Non-conservatism} = \begin{cases} 0 & \text{if REDY-calculated } \Delta CPR \geq .26 \\ .065 - \dfrac{\Delta CPR}{4} & \text{if REDY-calculated } \Delta CPR < .26 \end{cases}$$

Accordingly, we will require that the ΔCPR values used in the calculation of the operating limit MCPR be adjusted upwards for those transients involving a turbine trip or fast closure of the turbine throttle valves. This results in the following $\Delta CPRs$:

Transient	Calculated CPR by Fuel Type	
	8x8	8x8R
Load Rejection w/o Bypass	.18	.19
Loss of Feedwater Heater	.15	.15
Feedwater Controller Failure	.16	.16
Rod Withdrawal Error	.17	.19

There must be sufficient margin between the operating limit MCPR and the safety limit MCPR (1.07) to accommodate the most severe ΔCPR for each fuel type. The most severe $\Delta CPRs$ are:

0.18 for 8x8 fuel (based on load rejections without bypass)

0.19 for 8x8R fuel (based on load rejection without bypass and on rod withdrawal error)

The licensee has proposed an operating limit MCPR of 1.35 for both fuel types,(2) based on the fuel loading error accident (see §2.3.3 below). Thus, the margin between operating and safety limit MCPRs is 0.22, which is greater than the most severe $\Delta CPRs$ calculated in the transient analyses. Therefore, we find these analyses to be acceptable.

2.3 Accident Analyses

2.3.1 Core Spray Sparger Structural Integrity

Representatives of the Boston Edison Company and General Electric met with members of the NRC staff on February 29 and March 13, 1980, to discuss the discovery of crack-like indications observed on the core spray spargers inside the reactor vessel at the Pilgrim Nuclear Power Station Unit 1. The discussion also included the intended course of action to support a proposed startup plan.

In a submittal dated April 3, 1980 the Boston Edison Company requested a technical specification change, and provided an analysis that was designed to: (1) establish continued structural integrity of the core spray spargers for all modes of operat , (2) present the results of a LOCA analysis assuming no credit for core spray heat transfer and (3) describe the possible consequences of a potential loose part.

The proposed technical specification change is to modify the operating limit MAPLHGRs to ensure LOCA limits will not be exceeded.

The purpose of this evaluation is to present our review of the licensee analysis of the core spray spargers, wherein it was concluded that no loadings have been identified which could result in stresses that would cause the spargers to break during normal plant operation, transients or postulated loss-of-coolant accidents. Based on our review, we concur with the licensee's conclusions that no loads have been identified which could result in stresses that would further deteriorate the integrity of the core sparger. Further, we conclude that the Pilgrim Nuclear Power Station Unit 1 should be allowed to operate for one fuel cycle (approximately 18 months) before the defective sparger is replaced, recognizing that the LOCA analysis and Technical Specifications will provide for safe operating limits during the operating cycle.

2.3.1.1 ECCS Appendix K Analysis

By supplement to Reference 2 dated April 3, 1980, with supplement dated April 29, 1980, the licensee revised Pilgrim's ECCS conformance calculations to support plant operation with recently observed core spray sparger cracks. Substantial information and analyses have been provided which indicate that the core spray spargers will remain intact and functional for normal, transient and accident conditions. The licensee has conservatively assumed that the cracks in the core spray sparger eliminate all spray heat transfer from the most limiting fuel assembly for the ECCS conformance calculation. The licensee has also revised the heat transfer coefficient for the fuel assembly channel box outside surface from 0 to 25 BTU/hr-°F-ft^2 after reflood of the bypass region at the hot mode elevation. With these changes and the approved 10 CFR 50 Appendix K ECCS conformance calculation methods, the licensee developed reduction factors for plant MAPLHGR limits which assure that the acceptance criteria of 10 CFR 50.46 are met.

The assumption of no core spray heat transfer to the hot channel is conservative with respect to the fuel heatup calculation. The effect of this assumption on the depressurization calculation was also investigated per our request and was verified to be negligible for the Design Basis Accident (DBA). Also, because of the negligible effect on depressurization rate the effect on the break spectrum should also be negligible, and the current DBA should remain limiting. Therefore, the assumption is completely conservative and acceptable.

The assumption of increased heat transfer to the outside channel box surface is an additional model revision which is not simulated when core spray is assumed present.

The licensee has concluded that this assumption is conservative with respect to reality (Reference 11). We concur with this conclusion based on our own evaluation of the heat transfer mechanism and reflooding characteristics, and find the use of increased channel box heat transfer on the outer surface after bypass reflood of the hot mode level to be acceptable. Because of our requirement for redundant and diverse ECCS subsystems, i.e., core spray and low pressure coolant injection, the use of this modeling assumption is acceptable only for the current cycle of operation, and we will require a fully operational core spray system for future cycles.

Based on the above the use of the proposed MAPLHGR multipliers acceptably establishes limits which satisfy the 10 CFR 50.46 criteria.

2.3.2 Control Rod Drop Accident

The Rod Worth Minimizer (RWM) and associated rod pattern procedures at Pilgrim 1 use GE's Banked Position Withdrawal Sequence (BPWS). Generic analyses for BWR/2 and BWR/3 plants using BPWS, described and summarized in Reference 4, have shown that the peak fuel enthalpy deposited during a rod drop accident will be less than the 280 cal/gm limit, provided the maximum incremental control rod worth is not greater than 1.0% ΔK.

The licensee has performed an incremental control rod worth compliance calculation for Pilgrim 1 reload 4, and found a maximum incremental worth of 0.95% ΔK.(2) This is within the bounding analysis limit of 1.0%ΔK, and therefore we find the analysis to be acceptable.

2.3.3 Fuel Loading Error

The licensee has examined the reloaded core for potential fuel loading errors involving misoriented bundles. Potential errors involving bundles loaded into incorrect positions have also been analyzed by a method which considers the initial MCPR of each bundle in the core, and the resultant MCPR was shown to be greater than 1.07. This GE method for analysis of misoriented and misloaded bundles has been reviewed and approved by the staff.(12) The analyses which have been performed for Pilgrim 1 Cycle 5 are acceptable provided the core is operated with a MCPR $\geq$1.29 for all fuel types.

2.3.4 Overpressure Analysis

The overpressure analysis for the MSIV closure with high flux scram, which is the limiting overpressure event, has been performed in accordance with Reference 4. As specified in the staff evaluation included in Reference 4, the sensitivity of peak vessel pressure to failure of one safety valve has also been evaluated. We agree that there is sufficient margin between the peak calculated vessel pressure and the design limit pressure to allow for the failure of one valve. Therefore, the limiting overpressure event as analyzed by the licensee is considered acceptable.

2.4 Thermal-Hydraulic Stability

The results of the thermal-hydraulic stability analysis(2) show that the channel hydrodynamic and reactor core decay ratios at the natural circulation - 105% rod line intersection (which is the least stable physically attainable point of operation) are below the stability limit.

Because operation in the natural circulation mode will be prohibited by Technical Specification 3.6.A.6, there will be added margin to the stability limit, and this is acceptable.

2.5 Startup Test Program

The licensee has not changed his startup test program from that approved for the previous cycle. This program therefore remains acceptable.

2.6 Loose Part Analysis

One of the scheduled tasks for the Reload 4 refueling and maintenance outage was a visual inspection of the core spray spargers. During the inspection of these spargers, crack indications were discovered on the upper and lower sparger headers.[10] The effect of these cracks on the ECCS function is discussed above in §2.3.1. It is unlikely that the spargers will break up during Cycle 5. However, the licensee has examined the consequences of such a breakup.

The licensee considered a range of possible masses and shapes of loose parts, ranging from minute fragments to complete nozzle assemblies and 65 lb. sections of pipe. Because the core spray spargers are located within the shroud, only very small fragments can escape through the turning vanes in the steam separators and be carried into the annulus. Thus, there is no credible danger of even slight damage to the pressure boundary.

2.6.1 Mechanical Damage to Internals

The flow velocities within the core shroud are relatively low. The licensee has calculated these velocities above the core, between the channel boxes, and adjacent to the upper surface of the lower core plate.

Large pieces must remain in the plenum above the fuel, since there is no opening large enough to permit escape, either upward or downward. These objects will be too many to be levitated by the flow, and therefore cannot cause mechanical damage by repeated imparting. They should remain quiescent on the upper core structure.

Smaller pieces can be levitated by the flow. However, such fragments will have too low a mass to cause damage by impacting. They will probably migrate to low flow areas near the circumference or fall between the channel boxes to the lower core plate.

2.6.2 Mechanical Interferences

The only moving parts accessible to the loose objects are the control blades. Each control blade is exercised at least one notch every week, according to Technical Specifications 4.3.A.2. Thus, it is most unlikely that a blade would become jammed without the licensee discovering it and taking measures already spelled out in the Technical Specifications for inoperable blades.

The safety significance of a jammed control blade lies in the interference with the scram function. This is generally not a problem with BWRs since the very high force of the hydraulic control blade drive in scram mode is sufficient to lift a fuel assembly and tilt it out of the way. In any case, a considerable number (1/2 to 2/3 of the total) of randomly-placed jammed control blades is necessary to seriously interfere with the scram function.(13) Therefore, mechanical interference with the control blades is not a safety problem in this case.

2.6.3 Flow Blockage

Loose parts from the core spray spargers can block flow in the steam separators and at the top of the channel boxes. In addition, parts escaping the upper core area could be carried down through the jet pumps to the lower plenum and block the fuel inlet orifices.

In our judgment, there is negligible probability that enough steam separators could be blocked to cause a problem. In addition, the reduced core flow should alert the operator before such a problem became serious.

Similarly, we judge blockage at the top of an assembly to be not credible, since such blockage would require a very precise fit, sufficient weight to overcome the upward flow, and a means for placing the object below the fuel handling bails.

Finally, the licensee has examined the sizes of the steam separators and the fuel inlet orifices, and concluded that an object which is small enough to pass through the separators is essentially too small to block an orifice. Calculations of the consequences of flow blockage to a fuel assembly have been done previously.(14) Those calculations were used to show that even partial blockage of an inlet orifice would not cause a safety problem.

2.6.4 Other Considerations

Because the postulated loose objects are fragments of a core spray sparger which is designed to be in contact with the reactor coolant, the usual questions of chemical upset, corrosion, abrasion and coolant activity do not apply.

2.7 ATWS Recirculation Pump Trip

The licensee is installing an ATWS Recirculation Pump Trip (RPT) during the outage preceding Cycle 5. This trip is included in the transient analysis calculational simulations discussed in §2.2.2 above. Because operability of this new system will be enforced by means of appropriate technical specifications, this is acceptable.

Acceptability for the purpose of this cycle's transient analyses does not imply that this system is acceptable for ATWS prevention/ mitigation purposes. A separate review of this system for ATWS purposes is currently underway.

2.8 Margin to Spring Safety Valves

The Pilgrim 1 plant is equipped with four Safety/Relief valves (S/RV) and two Safety Valves (SV). Unlike the S/RVs, the safety valves do not have their discharges piped to the suppression pool, but instead discharge into the surrounding space. Thus, although credit is given for these valves for the overpressurization analysis (based on very infrequent events), anticipated occurrences should not open the safety valves.

Previously, the licensee required a 25 psi margin between the peak calculated pressure during most limiting transient and the safety valve setpoints. With this cycle the licensee wishes to change the requirement to a 60 psi margin, based on the MSIV closure with valve position scram. This is a much more common occurrence than turbine or generator trips with bypass failure.

Since the level of safety to the public is unchanged, and since the purpose of this margin is to avoid contamination within the drywell, we agree that this change is appropriate.

2.9 Technical Specifications

The licensee has proposed changes to the Technical Specifications for Cycle 5:

The safety limit MCPR has been changed from 1.06 to 1.07. This change is supported by §2.2.1 above, and is therefore acceptable.

The trip reduction factor, formerly based on the Total Pumping Factor (TPF), has been redefined in terms of Fractions of Rated Power (FRP) and Maximum Fraction of Limiting Power Density (MFLPD). Although the new formulation is mathematically equivalent, it is operationally easier to apply for cores containing more than one fuel type. We have examined and accepted this formulation on other dockets[15] and also find it acceptable here.

The limits on Average Planar Linear Heat Generation Rate (APLGHR) based on LOCA analyses, and on Operating Limit Minimum Critical Power Ratio (OLMCPR) have been altered to be consistent with the analyses submitted. Therefore, these new limits are acceptable.

An LHGR penalty to account for densification effects has been deleted. This densification effect has already been included in the new analysis of record[2,4] and therefore we agree that it need not be imposed via the Technical Specifications at this time.

A number of editorial changes have been made, substituting references for tabular and graphical information. This is a matter of convenience rather than safety or enforcibility, and therefore is acceptable.

Specifications relating to the new ATWS RPT system are being added. As was explained in §2.7 above, we find these specifications acceptable for this reload, as discussed in Section G of this report, but will continue review for ATWS purposes.

3.0 References

1. Letter, J. E. Howard (BECo) to T. A. Ippolito (NRC), dated December 12, 1979.

2. "Supplemental Reload Licensing Submittal for Pilgrim Nuclear Power Station Unit 1 Reload 4," NEDO-24224, November 1979, submitted as Attachment 2 to Reference 1.

3. Attachment 1 to Reference 1.

4. "General Electric Boiling Water Reactor Generic Reload Fuel Application," NEDE-24011,P-A, May 1977.

5. Letter, R. E. Engle (GE) to Division of Operating Reactors, NRC, dated January 30, 1979.

6. "Analytical Methods of Plant Transient Evaluations for the General Electric Boiling Water Reactor," NEDO-10802, February 1973.

7. "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," NEDO-24154, October 1978.

8. "Impact of One-Dimensional Transient Model on Plant Operations Limits," enclosure of Letter, E. D. Fuller (GE) to U. S. Nuclear Regulatory Commission, dated June 26, 1978.

9. Letter, R. J. Mattson (NRC) to General Electric Company (Attn G. G. Sherwood), dated March 20, 1979.

10. Attachment to Letter, J. E. Howard (BECo) to T. A. Ippolito (NRC) dated April 3, 1980.

11. Letter, J. E. Howard (BECo) to T. A. Ippolito, April 3, 1980.

12. Letter, D. G. Eisenhut (NRC) to R. Engel (GE), dated May 8, 1978.

13. "Anticipated Transients Without Scram for Light Water Reactors," NUREG-0460, Vol. 2, April 1978.

14. "Consequences of a Postulated Flow Blockage Incident in a Boiling Water Reactor," NEDO-10174, Rev. 1, October 1977.

15. Amendment 35 to Facility Operating License DPR-33, dated January 10, 1978.

B. Standby Gas Treatment System and Control Room High Efficiency Air Filtration System

1.0 Introduction

By a letter dated May 1, 1975, Boston Edison Company proposed to amend its operating license DPR-35 for Pilgrim Nuclear Power Station, Unit No. 1, by submitting a revision to the Technical Specifications. The proposed revision, which has subsequently been modified, includes changes to Sections 3.7.B and 4.7.B of the Technical Specifications for the Pilgrim Nuclear Power Station, Unit 1. The proposed Technical Specifications added the limiting conditions for operation, the surveillance requirements, and bases for the control room high-efficiency air filtration system, and revised the existing specifications for the standby gas treatment system. We have reviewed and evaluated these proposed changes and additions. Our evaluation was based on the model Technical Specification for engineered safety feature ventilation filter systems for operating nuclear reactors and on Positions C.5 (in-place testing criteria) and C.6 (laboratory testing criteria for activated charcoal) of Regulatory Guide 1.52, (Revision 2), "Design, Testing and Maintenance Criteria for Atmospheric Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants."

2.0 Evaluation

The licensee proposed to add the Technical Specifications for the control room high-efficiency air filtration system, which include the requirements for system operability, filter leakage and efficiencies, leakage and efficiency tests and test frequencies, actions to be taken when one train of the system becomes inoperable, flowrate requirements, heater power output, and functional test of the humidistats. In the proposed surveillance requirements, each train of the filter system is required to operate with the heaters in automatic control for at least 15 minutes every month. Operating each filter train for at least 15 minutes per month is sufficient to demonstrate operability of the air filter system in operating nuclear power reactors which do not have heaters in the air filter systems. Although the air filter systems in the control room high-efficiency air filtration system at the Pilgrim Nuclear Power Station, Unit No. 1, have heaters, they are controlled by humidistats and cannot be operated manually. Accordingly, we determined that the proposed surveillance requirement for operability of the filter train in the control room high-efficiency air filtration system for the Pilgrim Nuclear Power Station, Unit No. 1, meets the operability requirement of air filters for operating nuclear power reactors, and is acceptable.

We determined that the proposed Technical Specifications for the control room high-efficiency air filtration system and the bases are consistent with the model Technical Specifications and bases for control room emergency filtration system. Accordingly, we conclude that the proposed Technical Specifications and the bases for the control room high-efficiency air filtration system are acceptable.

The licensee proposed to revise the present Technical Specifications for the standby gas treatment system to include additional requirements for system operability, filter leakage and efficiency tests and test frequencies, additional actions to be taken when one train of the system becomes inoperable, flow-rate requirements, and functional test of the humidistats. In the proposed surveillance requirements, each train of the standby gas treatment system is required to operate for at least 15 minutes per month. Operating each filter train for at least 15 minutes per month is sufficient to demonstrate operability of the air filter system in operating nuclear power reactors which do not have heaters in the air filter system. The heaters in the standby gas treatment system at the Pilgrim Nuclear Power Station, Unit No. 1, are controlled by the humidistats and cannot be operated manually. Accordingly, we determined that the proposed surveillance requirement for operability of the filter train in the standby gas treatment system meets the operability requirement of air filter systems for operating nuclear power reactors, and is acceptable.

The licensee proposed to perform tests and analyses of the charcoal adsorber efficiency for methyl iodide after every 1440 hours of system operation. In view of the uncertainty in weathering of charcoal filters under operating conditions, we determined that test and analysis of the charcoal filter after 720 hours of system operation will be required to demonstrate acceptability. Accordingly, we require that the proposed Technical Specifications for the standby gas treatment system be modified to include test and analysis for methyl iodide collection efficiency by the charcoal adsorber be performed after every 720 hours of system operation.

We determined that the proposed Technical Specifications for the standby gas treatment system, modified to include test and analysis of the charcoal adsorbers after 720 hours of system operation, are consistent with the model Technical Specifications for standby gas treatment system. Accordingly, we conclude that the proposed Technical Specifications for the standby gas treatment system and gases, with the charcoal adsorbers test and analysis frequency of 720 hours, are acceptable.

3.0 Conclusion

Based on the above evaluation, we determined that the proposed changes and additions to the Technical Specification for the Pilgrim Nuclear Power Station meet the requirements of the model Technical Specifications for engineered safety feature ventilation filter systems for operating nuclear reactors and of Positions C.5 and C.6 in Regulatory Guide 1.52, (Revision 2). Accordingly, we conclude that the proposed amendment, as submitted and modified, is acceptable.

C. Degraded Grid Voltage Protection

1.0 Introduction

By letter dated June 3, 1977, the U. S. Nuclear Regulatory Commission (NRC) requested the Boston Edison Company to assess the susceptibility of the Pilgrim Nuclear Power Station Unit 1 Class 1E electrical equipment to sustained degraded voltage conditions at offsite power sources and to the interaction between the offsite and onsite emergency power systems. In addition, the NRC requested that the licensee compare the current design of the emergency power systems at the plant facilities with the NRC staff positions as stated in the June 3, 1977 letter, and that the licensee propose plant modifications, as necessary, to meet the NRC staff positions, or provide a detailed analysis which shows that the facility design has equivalent capabilities and protective features. Further, the NRC required certain Technical Specifications be incorporated into all facility operating licenses.

By letters dated August 8, 1977, August 24, 1977, September 27, 1979, and March 28, 1980, Boston Edison Company proposed design modifications and additions to the licensee's Technical Specifications. The design modifications include the installation of a degraded voltage protection system for the Class 1E equipment, consisting of (1) automatic protection against degraded grid voltage when the startup transformer is supplying power, and (2) an alarm with operator action to restore the bus voltage when unit auxiliary transformer is supplying power. The proposed additions to the Technical Specifications are in regard to the setpoints, calibrations, and surveillance requirements associated with the proposed voltage protection system.

2.0 Evaluation

Based on the information provided by Boston Edison Company, it has been determined that the proposed modifications comply with the staff's criteria when the emergency buses are being supplied by the startup transformer. All of the staff's requirements and design basis criteria have been met. The voltage setting and time delays will protect the Class 1E equipment from a sustained degraded voltage condition of the offsite power source.

However, the lack of automatic degraded voltage protection of Class 1E equipment when the emergency buses are being supplied by the unit auxiliary transformer is a concern because this is the prevalent mode of operation.

In a letter dated March 28, 1980, BECo committed to conduct new grid studies with the intent of providing automatic second level undervoltage protection for the unit auxiliary transformer. We expect these studies to be completed and any necessary modifications to be installed prior to startup from reload 5. We have agreed to allow credit for operator action during Cycle 5 power operation while new grid studies are being completed.

3.0 Conclusion

We have determined that Cycle 5 power operation with automatic degraded grid voltage protection only when the startup transformer is supplying power to class 1E buses is acceptable, provided that the technical specifications are modified to (1) require an operable emergency bus undervoltage alarm system when the unit auxiliary transformer is supplying power to Class 1E buses, and (2) require operator action to shut down the reactor when Class 1E bus voltage reaches an unacceptable low level. Accordingly, the technical specifications are being modified to include a limiting condition, required operator action, and surveillance requirements for the undervoltage alarm system.

D. Surveillance Frequency Definition

1.0 Introduction

By letter dated November 12, 1976, the licensee requested that the surveillance frequency for testing diesel generators be changed from "once per operating cycle" to once per 18 months. This submittal was followed by a more comprehensive request dated December 31, 1979. By letter dated February 5, 1980, the licensee requested that the former submittal be deleted. Therefore, no further action will be taken on the November 12, 1976 submittal.

2.0 Discussion

The licensee indicated in the December 31, 1979 submittal that the operating cycle interval was being changed to an 18 month cycle. This will reduce the number of refuelings by one every three years and provide for a potential increased plant availability and capacity factor. An increase in the time between refuelings should also contribute to reduced occupational exposures at the plant.

3.0 Evaluation

The proposed Technical Specification change defines the operating cycle interval to be 18 months. The proposed wording is consistent with the Standard Technical Specifications for General Electric Boiling Water Reactors, and will result in surveillance intervals that are consistent with GE STS.

4.0 Conclusion

We find the proposed change acceptable.

E. Diesel Generator Fuel Oil

1.0 Introduction

By letter dated February 1, 1978 Boston Edison Company requested that the Technical Specifications be changed to ensure diesel fuel quality is analyzed in accordance with the latest version of ASTM D975.

2.0 Discussion

The Regulatory Position in R.G. 1.137 "Fuel-Oil Systems for Standby Diesel Generators" Rev. 1 dated October 1979, in the discussion on quality of fuel oil, references ASTM D975-77 "Standard Specification for Diesel Fuel Oils." It also mentions the periodic sampling procedure which should be in accordance with ASTM D270-1975 "Standard Method of Sampling Petroleum and Petroleum Products." This guidance is consistent with current requirements in the Standard Technical Specifications for General Electric Boiling Water Reactors Rev. 2 dated August 1979.

3.0 Evaluation

In a letter dated January 7, 1980 regarding Quality Assurance Requirements for Diesel Generator Fuel Oil, the staff requested all power reactor licensees (except Arkansas Nuclear One Units 1 and 2) to include diesel generator fuel oil in the QA program for the plant. Revising the Pilgrim Unit 1 Technical Specifications to conform with the guidance in R.G. 1.137 will effectively achieve this objective. We have modified the licensee's request to include the latest ASTM D975 and the reference to ASTM D270. These changes were discussed with and agreed to by the licensee.

4.0 Conclusion

We find the licensee's request, as modified to be consistent with R.G. 1.137, to be acceptable.

F. Reactor Coolant Chemistry and Effluent Analyses

1.0 Introduction

By letter dated March 22, 1978 the licensee proposed a Technical Specification change for Reactor Coolant Chemistry, effluent analyses, and hydraulic snubbers. The hydraulic snubber change was issued with Amendment 40 to DPR-35 on February 4, 1980.

2.0 Discussion

a. Reactor Coolant Chemistry

The licensee proposed to include a time limit on the requirement to shutdown in the LCO for Coolant Chemistry. The bases were clarified to remove the incorrect inference that the normal range of conductivity indicates normal ranges for pH and chlorides.

b. Effluent Analyses

The licensee proposed to update the technical specifications to reflect the present more conservative methods utilizing a GeLi analyzer. Other editorial changes were proposed to update and clarify methods of analysis.

3.0 Evaluation

a. Reactor Coolant Chemistry

The proposed language for the action required in the event of off-standard chemistry conditions was determined to be more conservative than the present GE STS. The proposed revision to the Bases was modified to conform to the language in the present GE STS.

b. Effluent Analyses

The proposed changes to the effluent section are more conservative than the previous technical specifications. The changes became necessary when the sodium iodide analyzer was replaced with the GeLi full spectrum analyzer. The changes will clarify the methods of analysis.

4.0 Conclusion

The proposed changes to the reactor coolant chemistry section are conservative and conform to the current GE STS. The proposed changes to the effluent section are conservative and will clarify the methods of analysis. We therefore find the proposed changes acceptable.

G. Miscellaneous Technical Specification Changes

1.0 Introduction

By letter dated April 7, 1980, BECo applied for several modifications to Appendix A of Operating License No. DPR-35. The revisions to technical specifications were related to work and analyses completed during the 1980 Spring refueling outage. Each revision was treated in a separate attachment to the cover letter, and will be addressed in order of appearance.

2.0 Evaluation of Proposed Changes

2.1 Attachment A - Core Spray Sparger Break Detection Setpoint

2.1.1 Discussion

The licensee has determined, as a result of investigations under IE Circular 79-24, that the current alarm setpoint on instruments used to measure core spray differential pressure to monitor for core spray pipe breaks outside the shroud, should be changed to take into account the effect of density changes in the reference leg during normal rated power operation. The licensee proposed changing the alarm trip level from 5 $\pm$ 1.5 psid to $\leq$ .5 psid.

2.1.2 Evaluation

General Electric Service Information Letter No. 300 "Instrumentation for Core Spray Sparger Line Break Detection" predicts a 5.3 psid increase in differential pressure following a core spray header break. BECo states that a $\pm$ 1.5 psid range will allow for instrument drift. If the alarm trip level is set as allowed by the proposed technical specification, ($\leq$0.5 psid), it could be as high as +.5 psid and meet the specification. If the instrument were to drift +1.5 psid, the actual alarm trip level could be as high as +2.0 psid. This would be higher than the limit of 0.5 psid increasing, and might not alarm in an actual event. Therefore, we have revised the wording of the trip level setting to be consistent with the recommended limit including a range for instrument drift. BECo states that allowing for instrument drift in the alarm setpoint will likely cause the alarm to actuate when the plant is cooled down. Since this condition is also undesirable, BECo is investigating improved instruments that would not require such a wide range for instrument drift. The alarm trip level setpoint would be subject to revision in the event improved instruments are installed.

2.1.3 Conclusion

Changing the core spray differential pressure switch setpoint from 5($\pm$ 1.5) psid to -1 ($\pm$ 1.5) psid will take into consideration reference leg density fluctuations and setpoint drift. We find this change acceptable.

2.2 Attachment B - Hydraulic Snubbers

2.2.1 Discussion

The proposed deletion of Snubber No. SS-23-3-33 (HPCI) from Table 3.6.1 is an effort to ensure that the proper design configuration is maintained in accordance with the reanalysis per IE Bulletin #79-14.

2.2.2 Evaluation

The licensee stated that removal of this snubber from the HPCI piping system does not decrease the level of safety as originally designed to provide protection from structural damage to the piping as a result of a seismic or other event initiating dynamic loads. Through pipe stress reanalysis, the remaining snubbers have been determined to be of correct size and location to ensure proper system rigidity for the prevention of unrestrained pipe motion under dynamic loads.

We conclude that this snubber is not required to protect the HPCI piping system.

2.2.3 Conclusion

The removal of this snubber from the table of Safety Related Shock Suppressors is acceptable.

2.3 Attachment C - Electrical Power Systems

2.3.1 Discussion

The licensee proposed additional surveillance requirements on the shutdown transformer.

2.3.2 Evaluation

It is important to ensure that the shutdown transformer breakers close on to the safety related buses after the proper time delay. This technical specification change was requested by the staff during the review of degraded grid voltage protection which was discussed in an earlier section of this SER (Section C).

2.3.3 Conclusion

We find that the proposed change will provide the required verification and is acceptable.

2.4 Attachment D - Safety Related Valve Modifications

2.4.1 Discussion

BECo replaced the relief/safety valve 3 stage pilot operated activators with redesigned 2 stage pilot operated actuators during the refueling outage. This action was taken to reduce the likelihood of failures of BWR safety relief valves, as recommended in USNRC letter dated July 26, 1976. As a result of this modification, the valve bellows was removed from the valve topworks. The proposed change simply deletes the valve bellows operability requirements from the technical specifications.

2.4.2 Evaluation

The 3 stage topworks were provided with a valve bellows monitoring system to detect bellows failure. With the improved design no bellows exists and thus no further requirement exists for a bellows monitoring system.

2.4.3 Conclusion

The deletion of surveillance requirements on the safety relief valve bellows monitoring system is consistent with current plant design and is acceptable.

2.5 Attachment E - High Drywell Pressure Setpoint

2.5.1 Discussion

BECo proposed raising the High Drywell Pressure trip level setting from $\leq$ 2 psig to $\leq$ 2.5 psig. The reason for the change was to provide increased margin between the normal drywell pressure and the trip setpoint. Mark I Containment studies resulted in the requirement to maintain the drywell at least 1.5 psi above the wetwell, which is nominally at atmospheric pressure. With this requirement in effect, the plant is operated with the drywell pressure usually less than .5 psi lower than the ECCS actuation setpoint. An operational hardship is experienced in maintaining the required drywell/wetwell differential pressure and at the same time, avoiding spurious ECCS actuations.

2.5.2 Evaluation

The LOCA analyses for Pilgrim Unit 1 have been performed with a high D/W pressure setpoint of 2.0 psig, assuming an unpressurized drywell as the initial condition. Thus, a margin to the trip setpoint of as much as 2.0 psi would still be within the bounds of the accident analysis. Increasing the trip level setting to $\leq$ 2.5 psig will result in a nominal margin to the trip of only 1.0 psi, which is within the bounds of assumptions used in the previous LOCA analyses.

2.5.3 Conclusion

The proposed change will not decrease the performance of ECCS systems following drywell pressurization in a LOCA relative to that which was assumed in the accident analysis, and is acceptable.

2.6 Attachment F - Recirculation Pump Trip/Alternate Rod Insertion Initiation

2.6.1 Discussion

A safety evaluation for the ATWS Recirculation Pump Trip and Alternate Rod Insertion systems ATWS RPT/ARI was submitted on the docket for the Monticello Nuclear Generating Plant (Docket No. 50263, License No. DPR-22). This evaluation was reviewed by the NRC staff and a favorable Safety Evaluation Report was issued on February 23, 1977 for the RPT function. Since the RPT/ARI systems proposed for the Pilgrim Nuclear Power Station are essentially identical to that described in the Monticello evaluation only the minor differences and facets unique to the technical specifications will be considered in depth here.

The proposed limiting condition for operation requires the recirculation pump trip system to be operable when the reactor is in the RUN mode and the alternate rod insertion system to be operable in all modes except REFUELING. Since the capacity of the safety/relief valves is far in excess of the steam generation rate achievable in any other mode, there is no potential for vessel overpressurization in modes other than RUN. Restricting the LCO to the RUN mode for the RPT function is therefore appropriate.

The proposed operability requirements are similar to those of like systems. These requirements were assumed in the design and reliability analysis of the trip system.

The proposed surveillance requirements incorporate the fact that analog transmitters are used in ATWS RPT/ARI systems. These devices are a new, improved line of BWR instrumentation. The calibration frequency is therefore proposed to be once per operating cycle which is consistent with both the equipment capabilities and the requirements for similar equipment used by other reactor vendors. The calibration frequency for the trip units is proposed to be quarterly, the same as other similar protective instrumentation. Likewise, the test frequency is specified as monthly like that of other protective instrumentation. A sensor check is proposed once per day; this is considered to be an appropriate frequency, commensurate with the design applications and the fact that the recirculation pump trip/alternate rod insertion systems are backups to existing protective instrumentation.

With the implementation of the above proposed technical specification changes, there is adequate assurance that the ATWS RPT/ARI systems will perform to provide the intended plant protection in the extremely low probability of a plant transient with a failure to scram.

As discussed above, the ATWS RPT/ARI systems proposed are essentially identical with the systems as described on the Monticello docket. Several changes have been made to improve the system which are described below:

The Monticello ATWS RPT design as approved by the NRC Staff was not coupled with an ARI system. The ARI system design is; however, identical with the ARI design provided by Monticello in their safety evaluation report, with the exceptions noted below:

The Monticello RPT design includes a "Manual Initiation" push button on the operator control console. The proposed RPT/ARI design removes this push button but does provide manual control of the ARI function from the operator control console. Manual initiation of RPT at the console is unnecessarily redundant due to the variety of means already available to the operator for manually tripping the recirculation pumps or otherwise reducing recirculation flow.

The addition of the ARI function results in additional crowding of the operator control console. In order to reduce this crowding the manual reset push buttons have been eliminated and automatic reset logic substituted. Although the Monticello RPT design included a seal-in logic with manual reset it is unnecessarily redundant. Once a trip signal actuates the field breakers, it can be removed without affecting the state of the field breakers. The field breakers must be manually reset. Therefore, the automatic reset feature only reduces the manual actions required to reset the pumps for operation and does not affect the trip function. The ARI automatic reset logic includes a seal-in logic for a 30 second interval to assure sufficient time to blow down the pilot air header and insure complete rod insertion. The automatic reset cannot function, however, if the trip signal is still present. In this case an additional 30 seconds of delay will occur before reset and this sequence will continue until the trip signal is removed.

The high pressure setpoint for ATWS RPT/ARI as proposed is higher than the specification for the Monticello RPT. With the current plant configuration initiation of the ATWS RPT function is predicted during certain pressurization transients if the ATWS RPT setpoint is not raised. Since the initiation of ATWS RPT causes an increase in severity of the transients this is an undesirable condition. Raising the setpoint decouples the more frequent pressurization transients from ATWS RPT effects. With the proposed setpoint, the only events which will initiate ATWS RPT are the turbine/generator trip with bypass failure and the ASME overpressure protection event (MSIV closure with trip scram failure). The turbine/generator trip events will not result in exceeding the vessel pressure limit despite the increased severity due to ATWS RPT initiation and the limiting event will remain the MSIV closure with trip scram failure.

The MSIV closure event, with ATWS RPT, has a margin of 34 psi to the ASME code limit with the higher setpoint of 1160 psig. The technical specification will require 1175 $\pm$ 15 psig to allow for setpoint drift.

Increasing the ATWS RPT setpoint will also affect the peak pressure during an ATWS event. The selected setpoint will cause an increased peak pressure but it is expected to result in less than 25 psi increase.

The qualified DC power supplies and DC to AC inverter specified for the ATWS RPT/ARI systems are not currently available. Replacement of the DC power supplies and elimination of the inverter are necessary changes pending resolution of the supply difficulty. The design of each ATWS cabinet includes two qualified 24 VDC power supplies. One power supply is sourced by offsite 115 VAC which transfers to onsite generator power in the event of loss of offsite power. The second power supply is sourced by the station batteries (125 VDC) through an inverter (125 VDC to 115 VAC). The uninterruptible power supplied by the inverter allows the system logic to remain energized during the event of loss of offsite power until the transfer to onsite generators occurs. The temporary modifications will require manual action to initiate a pump trip and ARI during a loss of offsite power event.

In the unlikely event of loss of offsite power, a trip of the recirculation pumps and the ARI function can be initiated without the inverter. A pump trip occurs when the offsite AC power is interrupted deenergizing the motor of the recirculation pump MG sets. The ARI function can be initiated manually by the operator following an alarm from the ATWS loss of power annunciator. The ARI manual trip utilizes power from the 125 VDC station batteries to actuate the solenoid-operated instrument air valves.

A failure of one or both power supplies alerts the operator via the annunciator. He can utilize the MG manual controls to trip the recirculation pumps. The ARI can be manually initiated as explained above.

In order to maintain the diversity of the original design the following steps have been implemented:

1. The ATWS cabinets include provisions for installation of the inverters at a later date.

2. The ATWS cabinets include non-safety qualified power supplied to be replaced or qualified later.

The changes which have been incorporated into the proposed design do not change the basic functions of the ATWS systems as described for the Monticello RPT/ARI system.

2.6.2 Evaluation

The proposed technical specifications for ATWS RPT/ARI are consistent with the GE STS and will be issued for use in the interim until the staff completes its review of the installed design. Should further design changes be identified during our subsequent review that result in changes to the proposed Technical Specifications, such changes will be issued in a future license amendment.

2.6.3 Conclusion

The proposed Technical Specifications for ATWS/ARI are acceptable for use pending completion of the staff's review of the design details.

2.7 Attachment G - Containment Isolation

Valve Logic

2.7.1 Discussion

NUREG 0578 Section 2.1.4 (1) requires a diversity in parameters sensed for the initiation of containment isolation as described in Standard Review Plan 6.2.4. In particular, isolation of all non-essential systems must be accomplished based on diverse signals indicative of a LOCA obtained from qualified Class IE systems.

The reactor water sample valves presently receive only one isolation signal (low reactor water level) which meets the above criteria. A second isolation signal containing high drywell pressure will be added to the existing logics to provide the diverse signals required.

2.7.2 Evaluation

The new isolation signals have been obtained from new auxiliary relays wired in parallel to existing isolation trip relays in Panels C941 and C942. The addition of these Class IE relays to the existing circuits, the only interface with other safety components, does not degrade the logic circuit, as the wiring changes are accomplished in separate divisional Class IE Panels.

2.1.4 Containment Isolation in the staff's evaluation of BECo's compliance with Category "A" items resulting from TMI-2 Lessons Learned dated April 3, 1980, found the lic see's design acceptable.

2.7.3 Conclusion

We agree that these design modifications do not diminish the ability of the affected components to perform their required safety function assuming a single active failure. We find the proposed technical specification change adding the Reactor Water sample line isolation valves to Table 3.7.1 to be acceptable.

2.8 Attachment H - Fire Protection

Alternate Shutdown Stations

2.8.1 Discussion

The licensee has proposed Technical Specifications to provide surveillance requirements for equipment installed pursuant to Amendment #35 to DPR-35. This amendment required the capability for an alternate plant shutdown, independent of cabling and equipment in the cable spreading room. The proposed Technical Specifications are for modifications installed to meet the alternate shutdown requirement.

2.8.2 Evaluation

The staff has not completed its review of Pilgrim's alternate shutdown capability. However, alternate shutdown stations have been installed and will be available for use during operating cycle 5. The licensee has proposed Technical Specifications to require testing the alternate shutdown stations once/cycle to verify operability. The incorporation of these surveillance requirements into the Technical Specifications will not prejudice the staff's review of Pilgrim's alternate shutdown capability. At present, there is no basis for requiring testing of alternate shutdown systems on a more frequent interval.

2.8.3 Conclusion

Pending completion of the staff's review of Pilgrim's Alternate Shutdown capability for Fire Protection, we find the proposed surveillance requirements for alternate shutdown stations acceptable.

H. Reactor Protection System (RPS) Delay Time

1.0 Introduction

By letter dated April 24, 1980, BECo requested a technical specification change to the RPS response time from the opening of the sensor contact up to and including the opening of the trip actuator contacts. The current Technical Specification value is 100 milli-seconds and the proposed value is 50 milli-seconds.

2.0 Discussion

A review of transient analysis input parameters has shown that a value of 50 ms has been assumed for this time delay in Pilgrim analyses. Previous measurements at the Pilgrim station have indicated response times of less than 50 ms for this parameter.

3.0 Evaluation

This Technical Specification change is being requested to assure that the plant is operated within the assumptions used in the transient analyses. Decreasing the allowable response time from 100 to 50 ms is compatible with actual values and consistent with the transient analyses.

4.0 Conclusion

We find that the proposed change will improve safety margins and is acceptable.

Environmental Consideration

We have determined that the amendment does not authorize a change in effluent types or total amounts nor an increase in power level and will not result in any significant environmental impact. Having made this determination, we have further concluded that the amendment involves an action which is insignificant from the standpoint of environmental impact and, pursuant to 10 CFR §51.5(d)(4), that an environmental impact statement or negative declaration and environmental impact appraisal need not be prepared in connection with the issuance of this amendment.

Conclusion

We have concluded, based on the considerations discussed above, that: (1) because the amendment does not involve a significant increase in the probability or consequences of accidents previously considered and does not involve a significant decrease in a safety margin, the amendment does not involve a significant hazards consideration, (2) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, and (3) such activities will be conducted in compliance with the Commission's regulations and the issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public.

Dated: May 12, 1980