Docket file

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

October 11, 1994

Mr. John J. Barton
Vice President and Director
GPU Nuclear Corporation
Oyster Creek Nuclear Generating Station
Post Office Box 388
Forked River, NJ 08731

SUBJECT: ISSUANCE OF AMENDMENT (TAC NO. M89488)

Dear Mr. Barton:

The Commission has issued the enclosed Amendment No. 171 to Facility Operating License No. DPR-16 for the Oyster Creek Nuclear Generating Station, in response to your application dated May 12, 1994, as supplemented September 2, 1994.

The amendment revises Technical Specification Sections 3.1 and 4.1 for Protective Instrumentation, the associated bases, and tables to increase the surveillance test intervals and add allowable out-of service times. The Technical Specification changes will permit specified Channel Tests to be conducted quarterly rather than weekly or monthly. The amendment will enhance operational safety by reducing (1) the potential for inadvertent plant scrams, (2) excessive test cycles or equipment, and (3) the diversion of plant personnel and resources on unnecessary testing.

Two additional technical changes have been incorporated. The fist change involves extending the Channel Calibration interval for Average Power Range Monitor. The second change would add a quarterly Channel Calibration requirement for High Drywell Pressure (for Core Cooling) and Turbine Trip Scram Instrumentation.

Editorial changes have been incorporated in Instrumentation Sections 3.1 and 4.1 to provide clarity and consistency.

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A copy of the related Safety Evaluation is also enclosed. The notice of issuance will be included in the Commission's biweekly Federal Register notice.

Sincerely,

Original signed by:

Alexander W. Dromerick, Senior Project Manager
Project Directorate I-4
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket No. 50-219

Enclosures: 1. Amendment No. 171 to DPR-16
2. Safety Evaluation

cc w/encls: See next page

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

GPU NUCLEAR CORPORATION

AND

JERSEY CENTRAL POWER & LIGHT COMPANY

DOCKET NO. 50-219

OYSTER CREEK NUCLEAR GENERATING STATION

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 171
License No. DPR-16

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by GPU Nuclear Corporation, et al. (the licensee), dated May 12, 1994, as supplemented September 2, 1994, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. DPR-16 is hereby amended to read as follows:

   (2) <u>Technical Specifications</u>

   The Technical Specifications contained in Appendices A and B, as revised through Amendment No.171 , are hereby incorporated in the license. GPU Nuclear Corporation shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of the date of issuance, to be implemented within 90 days of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Phillip F. McKee, Director
Project Directorate I-4
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: October 11, 1994

ATTACHMENT TO LICENSE AMENDMENT NO. 171

FACILITY OPERATING LICENSE NO. DPR-16

DOCKET NO. 50-219

Replace the following pages of the Appendix A Technical Specifications with the enclosed pages as indicated. The revised pages are identified by amendment number and contain vertical lines indicating the areas of change.

Remove	Insert
3.1-1	3.1-1
3.1-2	3.1-2
3.1-3	3.1-3
3.1-4	3.1-4
3.1-4a	----
3.1-5	3.1-5
3.1-6	3.1-6
3.1-7	3.1-7
3.1-8	3.1-8
3.1-9	3.1-9
3.1-10	3.1-10
3.1-11	3.1-11
3.1-12	3.1-12
3.1-13	3.1-13
3.1-14	3.1-14
3.1-15	3.1-15
3.1-16	3.1-16
3.1-17	3.1-17
3.1-18	3.1-18
3.1-19	3.1-19
4.1-1	4.1-1
4.1-2	4.1-2
4.1-3	4.1-3
4.1-4	4.1-4
4.1-5	4.1-5
4.1-6	4.1-6
4.1-7	4.1-7
4.1-8	----
4.1-9	----
4.1-10	----

3.1 PROTECTIVE INSTRUMENTATION

Applicability: Applies to the operating status of plant instrumentation which performs a protective function.

Objective: To assure the OPERABILITY of protective instrumentation.

Specifications: A. The following operating requirements for plant protective instrumentation are given in Table 3.1.1:

1. The reactor mode in which a specified function must be OPERABLE including allowable bypass conditions.

2. The minimum number of OPERABLE instrument channels per OPERABLE trip system.

3. The trip settings which initiate automatic protective action.

4. The action required when the limiting conditions for operation are not satisfied.

B. 1. Failure of four chambers assigned to any one APRM shall make the APRM inoperable.

2. Failure of two chambers from one radial core location in any one APRM shall make that APRM inoperable.

C. 1. Any two (2) LPRM assemblies which are input to the APRM system and are separated in distance by less than three (3) times the control rod pitch may not contain a combination of more than three (3) inoperable detectors (i.e., APRM channel failed or bypassed, or LPRM detectors failed or bypassed) out of the four (4) detectors located in either the A and B, or the C and D levels.

2. A Travelling In-Core Probe (TIP) chamber may be used as an APRM input to meet the criteria of 3.1.B and 3.1.C.1, provided the TIP is positioned in close proximity to one of the failed LPRM's. If the criteria of 3.1.B.2 or 3.1.C.1 cannot be met, POWER OPERATION may continue at up to rated power level provided a control rod withdrawal block is OPERATING or at power levels less than 61% of rated power until the TIP can be connected, positioned and satisfactorily tested, as long as Specification 3.1.B.1 and Table 3.1.1 are satisfied.

Bases: The plant protection system automatically initiates protective functions to prevent exceeding established limits. In addition, other protective instrumentation is provided to initiate action which mitigates the consequences of accidents or terminates operator control. This specification provides the limiting conditions for operation necessary to preserve the effectiveness of these instrument systems.

Table 3.1.1 defines, for each function, the minimum number of OPERABLE instrument channels for an OPERABLE trip system for the various functions specified. There are usually two trip systems required or available for each function. The specified limiting conditions for operation apply for the indicated modes of operation. When the specified limiting condition cannot be met, the specified Actions Required shall be undertaken promptly to modify plant operation to the condition indicated in a normal manner. Conditions under which the specified plant instrumentation may be out-of-service are also defined in Table 3.1.1.

Except as noted in Table 3.1.1 an inoperable trip system will be placed in the tripped condition. A tripped trip system is considered OPERATING since by virtue of being tripped it is performing its required function. All sensors in the untripped trip system must be OPERABLE, except as follows:

1. The high temperature sensor system in the main steam line tunnel has eight sensors in each protection logic channel. This multiplicity of sensors serving a duplicate function permits this system to operate for twenty month nominal intervals without calibration. Thus, if one of the temperature sensors causes a trip in one of the two trip systems, there are several cross checks that would verify if this were a real one. If not, this sensor could be removed from service. However, a minimum of two of eight are required to be OPERABLE and only one of the two is required to accomplish a trip in a single trip system.

2. One APRM of the four in each trip system may be bypassed without tripping the trip system if core protection is maintained. Core protection is maintained by the remaining three APRM's in each trip system as discussed in Section 7.5.1.8.7 of the Updated FSAR.

3. One IRM channel in each of the two trip systems may be bypassed without compromising the effectiveness of the system. There are few possible sources of rapid reactivity input to the system in the low power low flow condition. Effects of increasing pressure at zero or low void content are minor, cold water from sources available during startup is not much colder than that already in the system, temperature coefficients are small, and control rod patterns are constrained to be uniform by operating procedures backed up by the rod worth minimizer. Worth of individual rods is very low in a uniform rod pattern. Thus, of all possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power rise. Because the flux distribution associated with uniform rod withdrawals does not involve high local peaks, and because several rods must be moved to change power by a significant percentage of rated, the rate of power rise is very slow. Generally the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the scram level, the rate of power rise is no more than five percent of rated per minute, and three OPERABLE IRM instruments in each trip system would be more than adequate to assure a scram before the power could exceed the safety limit. In many cases, if properly located, a single OPERABLE IRM channel in each trip system would suffice.

4. When required for surveillance testing, a channel is made inoperable. In order to be able to test its trip function to the final actuating device of its trip system, the trip system cannot already be tripped by some other means such as a mode switch, interlock, or manual trip. Therefore, there will be times during the test that the channel is inoperable but not tripped. For a two channel trip system, this means that full reliance is being placed on the channel that is not being tested. A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter.

5. Allowed outage times (AOT) to permit restoration of inoperable instrumentation to OPERABLE status are provided in Table 3.1.1. AOTs vary depending on type of function and the number of inoperable channels per function. If an inoperable channel cannot be restored to OPERABLE status within the AOT, the channel or the associated trip system must be placed in the tripped condition. Placing the inoperable channel in trip (or the associated trip system in trip) conservatively compensates for the inoperability and allows operation to continue. Alternatively, if it is not desired to place the channel (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram) the Action Required must be taken.

AOTs discussed in 4 (6 hours for surveillance) and 5 (repair AOTs in Table 3.1.1, Notes nn, oo and pp) above have been determined in accordance with References 1 through 6 except for instrumentation in Table 3.1.1, Sections M and N. Note kk has been provided to specify a 2 hour surveillance AOT for those instruments.

Bypasses of inputs to a trip system other than the IRM and APRM bypasses are provided for meeting operational requirements listed in the notes in Table 3.1.1. Note 'a' allows the "high water level in scram discharge volume" scram trip to be bypassed in the refuel mode. In order to reset the safety system after a scram condition, it is necessary to drain the scram discharge volume to clear this scram input condition. (This condition usually follows any scram, no matter what the initial cause might have been.) In order to do this, this particular scram function can be bypassed only in the refuel position. Since all of the control rods are completely inserted following a scram, it is permissible to bypass this condition because a control rod block prevents withdrawal as long as the switch is in the bypass condition for this function.

The manual scram associated with moving the mode switch to shutdown is used merely to provide a mechanism whereby the reactor protection system scram logic channels and the reactor manual control system can be energized. The ability to reset a scram twenty (20) seconds after going into the SHUTDOWN MODE provides the beneficial function of relieving scram pressure from the control rod drives which will increase their expected lifetime.

To permit plant operation to generate adequate steam and pressure to establish turbine seals and condenser vacuum at relatively low reactor power, the main condenser vacuum trip is bypassed until 600 psig. This bypass also applies to the main steam isolation valves for the same reason.

The action required when the minimum instrument logic conditions are not met is chosen so as to bring plant operation promptly to such a condition that the particular protection instrument is not required; or the plant is placed in the protection or safe condition that the instrument initiates. This is accomplished in a normal manner without subjecting the plant to abnormal operations conditions. The action and out-of-service requirements apply to all instrumentation within a particular function, e.g., if the requirements on any one of the ten scram functions cannot be met then control rods shall be inserted.

The trip level settings not specified in Specification 2.3 have been included in this specification. The bases for these settings are discussed below.

The high drywell pressure trip setting is $\leq$ 3.5 psig. This trip will scram the reactor, initiate core spray, initiate primary containment isolation, initiate automatic depressurization in conjunction with low-low-low-reactor water level, initiate the standby gas treatment system and isolate the reactor building. The scram function shuts the core down during the loss-of-coolant accidents. A steam leak of about 15 gpm and a liquid leak of about 35 gpm from the primary system will cause drywell pressure to reach the scram point; and, therefore, the scram provides protection for breaks greater than the above.

High drywell pressure provides a second means of initiating the core spray to mitigate the consequences of loss-of-coolant accident. Its trip setting of $\leq$3.5 psig initiates the core spray in time to provide adequate core cooling. The break size coverage of high drywell pressure was discussed above. Low-low water level and high drywell pressure in addition to initiating core spray also causes isolation valve closure. These settings are adequate to cause isolation to minimize the offsite dose within required limits.

It is permissible to make the drywell pressure instrument channels inoperable during performance of the integrated primary containment leakage rate test provided the reactor is in the COLD SHUTDOWN condition. The reason for this is that the Engineered Safety Features, which are effective in case of a LOCA under these conditions, will still be effective because they will be activated (when the Engineered Safety Features system is required as identified in the technical specification of the system) by low-low reactor water level.*

The scram discharge volume has two separate instrument volumes utilized to detect water accumulation. The high water level is based on the design that the water in the SDIV's, as detected by either set of level instruments, shall not be allowed to exceed 29.0 gallons; thereby, permitting 137 control rods to scram. To provide further margin, an accumulation of not more than 14.0 gallons of water, as detected by either instrument volume, will result in a rod block and an alarm. The accumulation of not more than 7.0 gallons of water, as detected in either instrument volume will result in an alarm.

Detailed analyses of transients have shown that sufficient protection is provided by other scrams below 45% power to permit bypassing of the turbine trip and generator load rejection scrams. However, for operational convenience, 40% of rated power has been chosen as the setpoint below which these trips are bypassed. This setpoint is coincident with bypass valve capacity.

A low condenser vacuum scram trip of 20 inches Hg has been provided to protect the main condenser in the event that vacuum is lost. A loss of condenser vacuum would cause the turbine stop valves to close, resulting in a turbine trip transient.

The low condenser vacuum trip provides a reliable backup to the turbine trip. Thus, if there is a failure of the turbine trip on low vacuum, the reactor would automatically scram at 20 inches Hg. The condenser is capable of receiving bypass steam until 7 inches Hg vacuum thereby mitigating the transient and providing a margin.

The settings to isolate the isolation condenser in the event of a break in the steam or condensate lines are based on the predicted maximum flows that these systems would experience during operation, thus permitting operation while affording protection in the event of a break. The settings correspond to a flow rate of less than three times the normal flow rate of $3.2X10^5$ lb/hr. Upon initiation of the alternate shutdown panel, this function is bypassed to prevent spurious isolation due to fire induced circuit faults.

The setting of ten times the stack release limit for isolation of the air-ejector offgas line is to permit the operator to perform normal, immediate remedial action if the stack limit is exceeded. The time necessary for this action would be extremely short when considering the annual averaging which is allowed under 10 CFR 20.106, and, therefore, would produce insignificant effects on doses to the public.

Four radiation monitors are provided which initiate isolation of the reactor building and operation of the standby gas treatment system. Two monitors are located in the ventilation ducts, one is located in the area of the refueling pool and one is located in the reactor vessel head storage area. The trip logic is basically a 1 out of 4 system. Any upscale trip will cause the desired action. Trip settings of 17 mr/hr in the duct and 100 mr/hr on the refueling floor are based upon initiating standby gas treatment system so as not to exceed allowed dose rates of 10 CFR 20 at the nearest site boundary.

The SRM upscale of 5×10^5 CPS initiates a rod block so that the chamber can be relocated to a lower flux area to maintain SRM capability as power is increased to the IRM range. Full scale reading is 1×10^6 CPS. This rod block is bypassed in IRM Ranges 8 and higher since a level of 5×10^5 CPS is reached and the SRM chamber is at its fully withdrawn position.

The SRM downscale rod block of 100 CPS prevents the instrument chamber from being withdrawn too far from the core during the period that it is required to monitor the neutron flux. This downscale rod block is also bypassed in IRM Ranges 8 and higher. It is not required at this power level since good indication exists in the Intermediate Range and the SRM will be reading approximately 5×10^5 CPS when using IRM Ranges 8 and higher.

The IRM downscale rod block in conjunction with the chamber full-in position and range switch setting, provides a rod block to assure that the IRM is in its most sensitive condition before startup. If the two latter conditions are satisfied, control rod withdrawal may commence even if the IRM is not reading at least 5%. However, after a substantial neutron flux is obtained, the rod block setting prevents the chamber from being withdrawn to an insensitive area of the core.

The APRM downscale setting of $\geq$ 2/150 full scale is provided in the RUN MODE to prevent control rod withdrawal without adequate neutron monitoring.

High flow in the main steamline is set at 120% of rated flow. At this setting the isolation valves close and in the event of a steam line break limit the loss of inventory so that fuel clad perforation does not occur. The 120% flow would correspond to the thermal power so this would either indicate a line break or too high a power.

Temperature sensors are provided in the steam line tunnel to provide for closure of the main steamline isolation valves should a break or leak occur in this area of the plant. The trip is set at 50°F above ambient temperature at rated power. This setting will cause isolation to occur for main steamline breaks which result in a flow of a few pounds per minute or greater. Isolation occurs soon enough to meet the criterion of no clad perforation.

The low-low-low water level trip point is set at 4'8" above the top of the active fuel and will prevent spurious operation of the automatic relief system. The trip point established will initiate the automatic depressurization system in time to provide adequate core cooling.

Specification 3.1.B.1 defines the minimum number of APRM channel inputs required to permit accurate average core power monitoring. Specifications 3.1.B.2 and 3.1.C.1 further define the distribution of the OPERABLE chambers to provide monitoring of local power changes that might be caused by a single rod withdrawal. Any nearby, OPERABLE LPRM chamber can provide the required input for average core monitoring. A Travelling Incore Probe or Probes can be used temporarily to provide APRM input(s) until LPRM replacement is possible. Since APRM rod block protection is not required below 61% of rated power, as discussed in Section 2.3, Limiting Safety System Settings, operation may continue below 61% as long as Specification 3.1.B.1 and the requirements of Table 3.1.1 are met. In order to maintain reliability of core monitoring in that quadrant where an APRM is inoperable, it is permitted to remove the OPERABLE APRM from service for calibration and/or test provided that the same core protection is maintained by alternate means.

In the rare event that Travelling In-core Probes (TIPs) are used to meet the requirements 3.1.B or 3.1.C, the licensee may perform an analysis of substitute LPRM inputs to the APRM system using spare (non-APRM input) LPRM detectors and change the APRM system as permitted by 10 CFR 50.59.

Under assumed loss-of-coolant accident conditions and certain loss of offsite power conditions with no assumed loss-of-coolant accident, it is inadvisable to allow the simultaneous starting of emergency core cooling and heavy load auxiliary systems in order to minimize the voltage drop across the emergency buses and to protect against a potential diesel generator overload. The diesel generator load sequence time delay relays provide this protective function and are set accordingly. The repetitive accuracy rating of the timer mechanism as well as parametric analyses to evaluate the maximum acceptable tolerances for the diesel loading sequence timers were considered in the establishment of the appropriate load sequencing.

Manual actuation can be accomplished by the operator and is considered appropriate only when the automatic load sequencing has been completed. This will prevent simultaneous starting of heavy load auxiliary systems and protect against the potential for diesel generator overload.

Also, the Reactor Building Closed Cooling Water and Service Water pump circuit breakers will trip whenever a loss-of-coolant accident condition exists. This is justified by Amendment 42 of the Licensing Application which determined that these pumps were not required during this accident condition.

The drywell high radiation setpoint will ensure a timely closure of the large vent and purge isolation valves to prevent releases from exceeding ten percent of the dose guideline values allowed by 10 CFR 100. The containment vent and purge isolation function is provided in response to NUREG 0737 Item II E.4.2.7.

<u>References</u>:

(1) NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System."

(2) NEDC-30936P-A, "BWR Owners' Group Technical Specification Improvement Methodology (With Demonstration for BWR ECCS Actuation Instrumentation)," Parts 1 and 2.

(3) NEDC-30851P-A, Supplement 1, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation."

(4) NEDC-30851P-A, Supplement 2, "Technical Specification Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation."

(5) NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation."

(6) GENE-770-06-1-A, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications."

TABLE 3.1.1 PROTECTIVE INSTRUMENTATION REQUIREMENTS

Function	Trip Setting	Reactor Modes in which Function Must Be OPERABLE: Shutdown	Refuel	Startup	Run	Min. No. of OPERABLE or OPERATING [tripped] Trip Systems	Min. No. of Instrument Channels Per OPERABLE Trip System	Action Required*
A. Scram								
1. Manual Scram		X	X	X	X	2	1	Insert control rods
2. High Reactor Pressure	**		X(s)	X(ll)	X	2	2(nn)	
3. High Drywell Pressure	≤ 3.5 psig		X(u)	X(u)	X	2	2(nn)	
4. Low Reactor Water Level	**		X	X	X	2	2(nn)	
5. a. High Water Level in Scram Discharge Volume North Side	≤ 29 gal.		X(a)	X(z)	X(z)	2	2(nn)	
b. High Water Level in Scram Discharge Volume South Side	≤ 29 gal.		X(a)	X(z)	X(z)	2	2(nn)	
6. Low Condenser Vacuum	≥ 20 in. hg.			X(b)	X	1	3(mm)(nn)	
7. DELETED								
8. Average Power Range Monitor (APRM)	**		X(c,s)	X(c)	X(c)	2	3(nn)	
9. Intermediate Range Monitor (IRM)	**		X(d)	X(d)		2	3(nn)	
10. Main Steamline Isolation Valve Closure	**		X(b,s)	X(b)	X	2	4(nn)	
11. Turbine Trip Scram	**				X(j)	2	4(nn)	
12. Generator Load Rejection Scram	**				X(j)	2	2(nn)	

TABLE 3.1.1 PROTECTIVE INSTRUMENTATION REQUIREMENTS

Function	Trip Setting	Reactor Modes in which Function Must Be OPERABLE				Min. No. of OPERABLE or OPERATING [tripped] Trip Systems	Min. No. of Instrument Channels Per OPERABLE Trip System	Action Required*
		Shutdown	Refuel	Startup	Run			
B. Reactor Isolation								
1. Low-Low Reactor Water Level	**	X	X	X	X	2	2(oo)	Close main steam isolation valves and close isolation condenser vent valves, or PLACE IN COLD SHUTDOWN CONDITION
2. High Flow in Main Steam-line A	≤120% rated	X(s)	X(s)	X	X	2	2(oo)	
3. High Flow in Main Steam-line B	≤120% rated	X(s)	X(s)	X	X	2	2(oo)	
4. High Temperature in Main Steam-line Tunnel	≤Ambient at Power + 50°F	X(s)	X(s)	X	X	2	2(oo)	
5. Low Pressure in Main Steam-line	**			X(cc)	X	2	2(oo)	
6. DELETED								
C. Isolation Condenser Initiation								
1. High Reactor Pressure	**	X(s)	X(s)	X(ll)	X	2	2(pp)	PLACE IN COLD SHUTDOWN CONDITION
2. Low-Low Reactor Water Level	≥7'2" above TOP OF ACTIVE FUEL	X(s)	X(s)	X	X	2	2(pp)	

TABLE 3.1.1 PROTECTIVE INSTRUMENTATION REQUIREMENTS

Function	Trip Setting	Reactor Modes in which Function Must Be OPERABLE: Shutdown	Refuel	Startup	Run	Min. No. of OPERABLE or OPERATING [tripped] Trip Systems	Min. No. of Instrument Channels Per OPERABLE Trip System	Action Required*
D. Core Spray								
1. Low-Low Reactor Water Level	**	X(t)	X(t)	X(t)	X	2	2(pp)	Consider the respective core spray loop inoperable, and comply with Spec. 3.4
2. High Drywell Pressure	≤ 3.5 psig	X(t)	X(t)	X(t)	X	2(k)	2(k)(pp)	
3. Low Reactor Pressure (valve permissive)	≥ 285 psig	X(t)	X(t)	X(t)	X	2	2(pp)	
E. Containment Spray								
Comply with Technical Specification 3.4								
F. Primary Containment Isolation								
1. High Drywell Pressure	≤ 3.5 psig	X(u)	X(u)	X(u)	X	2(k)	2(k)(oo)	Isolate containment or PLACE IN COLD SHUT-DOWN CONDITION
2. Low-Low Reactor Water Level	≥ 7'2" above TOP OF ACTIVE FUEL	X(u)	X(u)	X(u)	X	2	2(oo)	
G. Automatic Depressurization								
1. High Drywell Pressure	< 3.5 psig	X(v)	X(v)	X(v)	X	2(k)	2(k)(pp)	See note h
2. Low-Low-Low Reactor Water Level	≥ 4'8" above TOP OF ACTIVE FUEL	X(v)	X(v)	X(v)	X	2	2(pp)	See note h
3. AC Voltage	NA			X(v)	X	2	2(pp)	Prevent auto depressur-ization on loss of AC power. See note i

TABLE 3.1.1 PROTECTIVE INSTRUMENTATION REQUIREMENTS

Function	Trip Setting	Reactor Modes in which Function Must Be OPERABLE: Shutdown	Refuel	Startup	Run	Min. No. of OPERABLE or OPERATING [tripped] Trip Systems	Min. No. of Instrument Channels Per OPERABLE Trip System	Action Required*
H. Isolation Condenser Isolation (See Note hh)								Isolate affected Isolation Condenser, comply with Spec. 3.8 See note dd
1. High Flow Steam Line	≤ 20 psig P	X(s)	X(s)	X	X	2	2(oo)	
2. High Flow Condensate Line	≤ 27" P H_2O	X(s)	X(s)	X	X	2	2(oo)	
I. Offgas System Isolation								
1. High Radiation In Offgas Line (e)	≤ 2.1/$\bar{E}$ Ci/sec	X(s)	X(s)	X	X	1(ii)	2(ii)	See Note jj
J. Reactor Building Isolation and Standby Gas Treatment System Initiation								Isolate Reactor Building and Initiate Standby Gas Treatment System or Manual Surveillance for not more than 24 hours (total for all instruments under J) in any 30-day period
1. High Radiation Reactor Building Operating Floor	≤ 100 Mr/Hr	X(w)	X(w)	X	X	1	1	
2. Reactor Building Ventilation Exhaust	≤ 17 Mr/Hr	X(w)	X(w)	X	X	1	1	
3. High Drywell Pressure	≤ 3.5 psig	X(u)	X(u)	X	X	1(k)	2(k)	
4. Low-Low Reactor Water Level	≥ 7'2" above TOP OF ACTIVE FUEL	X	X	X	X	1	2	

TABLE 3.1.1 PROTECTIVE INSTRUMENTATION REQUIREMENTS

Function	Trip Setting	Reactor Modes in which Function Must Be OPERABLE: Shutdown	Refuel	Startup	Run	Min. No. of OPERABLE or OPERATING [tripped] Trip Systems	Min. No. of Instrument Channels Per OPERABLE Trip System	Action Required*
K. Rod Block								No control rod withdrawals permitted
1. SRM Upscale	$\leq 5x10^5$ cps		X	X(l)		1	2	
2. SRM Downscale	$\geq$100cps(f)		X	X(l)		1	2	
3. IRM Downscale	$\geq$5/125 fullscale (g)		X	X		2	3	
4. APRM Upscale	**		X(s)	X	X	2	3(c)	
5. APRM Down-scale	$\geq$2/150 fullscale				X	2	3(c)	
6. IRM Upscale	$\leq$108/125 fullscale		X	X		2	3	
7. a) water level high scram discharge volume North	$\leq$14 gallons		X(z)	X(z)	X(z)	1	1 per instrument volume	
b) water level high scram discharge volume South	$\leq$ 14 gallons		X(z)	X(z)	X(z)	1	1 per instrument volume	

L. Condenser Vacuum Pump Isolation

DELETED

TABLE 3.1.1 PROTECTIVE INSTRUMENTATION REQUIREMENTS

Function	Trip Setting	Reactor Modes in which Function Must Be OPERABLE: Shutdown	Refuel	Startup	Run	Min. No. of OPERABLE or OPERATING [tripped] Trip Systems	Min. No. of Instrument Channels Per OPERABLE Trip System	Action Required*
M. Diesel Generator Load Sequence Timers	Time delay after energizaion of relay							
1. CRD pump	60 sec ± 15%	X	X	X	X	2(m)	1(n)(kk)	Consider the pump inoperable and comply with Spec. 3.4.D (see Note q)
2. Service Water Pump (aa)	120 sec.± 15% (SK1A) 10 sec. ± 15% (SK2A) (SK7A) (SK8A)	X	X	X	X	2(o)	2(p)(kk)	Consider the pump inoperable and comply within 7 days (See Note q)
3. Reactor Building Closed Cooling Water Pump (bb)	166 Sec.± 15%	X	X	X	X	2(m)	1(n)(kk)	Consider the pump inoperable and comply within 7 days (See Note q)
N. Loss of Power								
a. 4.16KV Emergency Bus Undervoltage (Loss of Voltage)	**	X(ff)	X(ff)	X(ff)	X(ff)	2	1(kk)	
b. 4.16 KV Emergency Bus Undervoltage (Degraded Voltage)	**	X(ff)	X(ff)	X(ff)	X(ff)	2	3(kk)	See note ee

TABLE 3.1.1 PROTECTIVE INSTRUMENTATION REQUIREMENTS

Function	Trip Setting	Reactor Modes in which Function Must Be OPERABLE: Shutdown	Refuel	Startup	Run	Min. No. of OPERABLE or OPERATING [tripped] Trip Systems	Min. No. of Instrument Channels Per OPERABLE Trip System	Action Required*
O. Containment Vent and Purge Isolation								
1. Drywell High Radiation	≤74.6 R/hr	X(u)	X(u)	X(u)	X	1	1	Isolate vent and purge pathways or PLACE IN COLD SHUTDOWN CONDITION

TABLE 3.1.1 (CONT'D)

* Action required when minimum conditions for operation are not satisfied. Also permissible to trip inoperable trip system. A channel may be placed in an inoperable status for up to six hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE instrument channel in the same trip system is monitoring that parameter.

** See Specification 2.3 for Limiting Safety System Settings.

Notes:

a. Permissible to bypass, with control rod block, for reactor protection system reset in REFUEL MODE.
b. Permissible to bypass below 800 psia in REFUEL and STARTUP MODES.
c. One (1) APRM in each OPERABLE trip system may be bypassed or inoperable provided the requirements of Specification 3.1.C and 3.10.C are satisfied. Two APRM's in the same quadrant shall not be concurrently bypassed except as noted below or permitted by note.

   Any one APRM may be removed from service for up to six hours for test or calibration without inserting trips in its trip system only if the remaining OPERABLE APRM's meet the requirements of Specification 3.1.B.1 and no control rods are moved outward during the calibration or test. During this short period, the requirements of Specifications 3.1.B.2, 3.1.C and 3.10.C need not be met.
d. The IRMs shall be inserted and OPERABLE until the APRMs are OPERABLE and reading at least 2/150 full scale.
e. Offgas system isolation trip set at $\leq 2.1/\bar{E}$ Ci/sec where $\bar{E}$ = average gamma energy from noble gas in offgas after holdup line (Mev). Air ejector isolation valve closure time delay shall not exceed 15 minutes.
f. Unless SRM chambers are fully inserted.
g. Not applicable when IRM on lowest range.
h. One instrument channel in each trip system may be inoperable provided the circuit which it operates in the trip system is placed in a simulated tripped condition. If repairs cannot be completed within 72 hours the reactor shall be PLACED IN THE COLD SHUTDOWN CONDITION. If more than one instrument channel in any trip system becomes inoperable, the reactor shall be PLACED IN THE COLD SHUTDOWN CONDITION. Relief valve controllers shall not be bypassed for more than 3 hours (total time for all controllers) in any 30-day period and only one relief valve controller may be bypassed at a time.
i. The interlock is not required during the start-up test program and demonstration of plant electrical output but shall be provided following these actions.
j. Not required below 40% of turbine rated steam flow.

k. All four (4) drywell pressure instrument channels may be made inoperable during the integrated primary containment leakage rate test (See Specification 4.5), provided that the plant is in the COLD SHUTDOWN condition and that no work is performed on the reactor or its connected systems which could result in lowering the reactor water level to less than 4'8" above the TOP OF THE ACTIVE FUEL.
l. Bypass in IRM Ranges 8,9, and 10.
m. There is one time delay relay associated with each of two pumps.
n. One time delay rely per pump must be OPERABLE.
o. There are two time delay relays associated with each of two pumps. One timer per pump is for sequence starting (SK1A, SK2A) and one timer per pump is for tripping the pump circuit breaker (SK7A, SK8A).
p. Two time delay relays per pump must be OPERABLE.
q. Manual initiation of affected component can be accomplished after the automatic load sequencing is completed.
r. Time delay starts after closing of containment spray pump circuit breaker.
s. These functions not required to be OPERABLE with the reactor temperature less than 212°F and the vessel head removed or vented or during REACTOR VESSEL PRESSURE TESTING.
t. These functions may be inoperable or bypassed when corresponding portions in the same core spray system logic train are inoperable per Specification 3.4.A.
u. These functions not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required to be maintained.
v. These functions not required to be OPERABLE when the ADS is not required to be OPERABLE.
w. These functions must be OPERABLE only when irradiated fuel is in the fuel pool or reactor vessel and SECONDARY CONTAINMENT INTEGRITY is required per Specification 3.5.B.
y. Deleted
z. The bypass function to permit scram reset in the SHUTDOWN or REFUEL MODE with control rod block must be OPERABLE in this mode.
aa. Pump circuit breakers will be tripped in 10 seconds ± 15% during a LOCA by relays SK7A and SK8A.
bb. Pump circuit breakers will trip instantaneously during a LOCA.
cc. Only applicable during STARTUP MODE while OPERATING in IRM range 10.
dd. If an isolation condenser inlet (steam side) isolation valve becomes or is made inoperable in the open position during the RUN MODE comply with Specification 3.8.E. If an AC motor-operated outlet (condensate return) isolation valve becomes or is made inoperable in the open position during the RUN MODE comply with Specification 3.8.F.
ee. With the number of OPERABLE channels one less than the Min. No. of OPERABLE Instrument Channels per OPERABLE Trip System, operation may proceed until performance of the next required Channel Functional Test provided the inoperable channel is placed in the tripped condition within 1 hour.
ff. This function is not required to be OPERABLE when the associated safety bus is not required to be energized or fully OPERABLE as per applicable sections of these Technical Specifications.

TABLE 3.1.1 (CONT'D)

gg. Deleted

hh. The high flow trip function for "B" Isolation Condenser is bypassed upon initiation of the alternate shutdown panel. This prevents a spurious trip of the Isolation Condenser in the event of fire induced circuit damage.

ii. Instrument shall be OPERABLE during main condenser air ejector operation except that a channel may be taken out-of-service for the purpose of a check, calibration, test, or maintenance without declaring it inoperable.

jj. With no channel OPERABLE, main condenser offgas may be released to the environment for as long as 72 hours provided the stack radioactive noble gas monitor is OPERABLE. Otherwise, be in at least SHUTDOWN CONDITION within 24 hours.

kk. One channel may be placed in an inoperable status for up to two hours for required surveillance without placing the trip system in the tripped condition.

ll. This function not required to be OPERABLE with the reactor vessel head removed or unbolted.

mm. "Instrument Channel" in this case refers to the bellows which sense vacuum in each of the three condensers (A, B, and C), and "Trip System" refers to vacuum trip systems 1 and 2.

nn. With one required channel inoperable in one Trip System, within 12 hours, restore the inoperable channel or place the inoperable channel and/or that Trip System in the tripped▲ condition.

With two or more required channels inoperable:

1. Within one hour, verify sufficient channels remain OPERABLE or tripped▲ to maintain trip capability, and
2. Within 6 hours, place the inoperable channel(s) in one Trip System and/or that Trip System▲▲ in the tripped condition▲, and
3. Within 12 hours, restore the inoperable channels in the other Trip System to an OPERABLE status or tripped▲.

Otherwise, take the Action Required.

▲ An inoperable channel or Trip System need not be placed in the tripped condition where this would cause the Trip Function to occur. In these cases, if the inoperable channel is not restored to OPERABLE status within the required time, the Action Required shall be taken.

▲▲ This action applies to that Trip System with the most inoperable channels; if both Trip Systems have the same number of inoperable channels, the action can be applied to either Trip System.

TABLE 3.1.1 (CONT'D)

oo. With one required channel inoperable in <u>one</u> Trip System, either

1. Place the inoperable channel in the tripped condition within

   a. 12 hours for parameters common to Scram Instrumentation, and
   b. 24 hours for parameters not common to Scram Instrumentation.

   or

2. Take the Action Required.

With one required channel inoperable in <u>both</u> Trip Systems,

1. Place the inoperable channel in one Trip System in the tripped condition within one hour, and

2. a. Place the inoperable channel in the remaining Trip System in the tripped condition within

   (1) 12 hours for parameters common to Scram Instrumentation, and
   (2) 24 hours for parameters not common to Scram Instrumentation.

   or

   b. Take the Action Required.

pp. With one or more required channels inoperable per Trip System:

1. For one channel inoperable, within 24 hours place the inoperable channel in the tripped condition or take the Action Required.

2. With more than one channel inoperable, take the Action Required.

SECTION 4

SURVEILLANCE REQUIREMENTS

4.1 PROTECTIVE INSTRUMENTATION

Applicability: Applies to the surveillance of the instrumentation that performs a safety function.

Objective: To specify the minimum frequency and type of surveillance to be applied to the safety instrumentation.

Specification: Instrumentation shall be checked, tested, and calibrated as indicated in Tables 4.1.1 and 4.1.2 using the definitions given in Section 1.

Basis: Surveillance intervals are based on reliability analyses and have been determined in accordance with General Electric Licensing Topical Reports given in References 1 through 5.

The functions listed in Table 4.1.1 logically divide into three groups:

a. On-off sensors that provide a scram function or some other equally important function.

b. Analog devices coupled with a bi-stable trip that provides a scram function or some other vitally important function.

c. Devices which only serve a useful function during some restricted mode of operation, such as startup or shutdown, or for which the only practical test is one that can be performed only at shutdown.

Group (b) devices utilize an analog sensor followed by an amplifier and bi-stable trip circuit. The sensor and amplifier are active components and a failure would generally result in an upscale signal, a downscale signal, or no signal. These conditions are alarmed so a failure would not go undetected. The bi-stable portion does need to be tested in order to prove that it will assume its tripped state when required.

Group (c) devices are active only during a given portion of the operational cycle. For example, the IRM is inactive during full-power operation and active during startup. Thus, the only test that is significant is the one performed just prior to shutdown and startup. The condenser Low Vacuum trip can only be tested during shutdown, and although it is connected into the reactor protection system, it is not required to protect the reactor. Testing at each REFUELING OUTAGE is adequate. The switches for the high temperature main steamline tunnel are not accessible during normal operation because of their location above the main steam lines. Therefore, after initial calibration and in-place OPERABILITY checks, they will not be tested between refueling shutdowns. Considering the physical arrangement of the piping which would allow a steam leak at any of the four sensing locations to affect the other locations, it is considered that the function is not jeopardized by limiting calibration and testing to refueling outages.

The logic of the instrument safety systems in Table 4.1.1 is such that testing the instrument channels also trips the trip system, verifying that it is OPERABLE. However, certain systems require coincident instrument channel trips to completely test their trip systems. Therefore, Table 4.1.2 specifies the minimum trip system test frequency for these tripped systems. This assures that all trip systems for protective instrumentation are adequately tested, from sensors through the trip system.

IRM calibration is to be performed during reactor startup. The calibration of the IRMs during startup will be significant since the IRMs will be relied on for neutron monitoring and reactor protection up to 38.4% of rated power during a reactor startup.

General Electric Licensing Topical Report NEDC-30851P-A (Reference 1), Section 5.7 indicates that the major contributor to reactor protection system unavailability is common cause failure of the automatic scram contactors. Analysis showed a weekly test interval to be optimum for scram contactors. The test of the automatic scram contactors can be performed as part of the Channel Calibration or Test of Scram Functions or by use of the subchannel test switches.

<u>References</u>: (1) NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System."

(2) NEDC-30936P-A, "BWR Owners' Group Technical Specification Improvement Methodology (With Demonstration for BWR ECCS Actuation Instrumentation)," Parts 1 and 2.

(3) NEDC-30851P-A, Supplement 1, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation."

(4) NEDC-30851P-A, Supplement 2, "Technical Specification Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation."

(5) NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation."

TABLE 4.1.1

MINIMUM CHECK, CALIBRATION AND TEST FREQUENCY FOR PROTECTIVE INSTRUMENTATION

Instrument Channel	Check	Calibrate	Test	Remarks (Applies to Test and Calibration)
1. High Reactor Pressure	1/d	Note 3	1/3 mo	
2. High Drywell Pressure (Scram)	N/A	1/3 mo	1/3 mo	By application of test pressure
3. Low Reactor Water Level	1/d	Note 3	1/3 mo	
4. Low-Low Water Level	1/d	Note 3	1/3 mo	
5. High Water Level in Scram Discharge Volume				
a. Digital	N/A	1/3 mo	1/3 mo	By varying level in sensor columns
b. Analog	N/A	Note 3	1/3 mo	
6. Low-Low-Low Water Level	N/A	1/3 mo	1/3 mo	By application of test pressure
7. High Flow in Main Steamline	1/d	1/3 mo	1/3 mo	By application of test pressure
8. Low Pressure in Main Steamline	N/A	1/3 mo	1/3 mo	By application of test pressure
9. High Drywell Pressure (Core Cooling)	1/d	1/3 mo	1/3 mo	By application of test pressure
10. Main Steam Isolation Valve (Scram)	N/A	N/A	1/3 mo	By exercising valve
11. APRM Level	N/A	1/3d	N/A	Output adjustment using operational type heat balance during POWER OPERATION
APRM Scram Trips	Note 2	1/3 mo	1/3 mo	Using built-in calibration equipment during POWER OPERATION
12. APRM Rod Blocks	Note 2	1/3 mo	1/3 mo	Upscale and downscale

TABLE 4.1.1 (cont'd)

Instrument Channel	Check	Calibrate	Test	Remarks (Applies to Test and Calibration)
13. DELETED				
14. High Radiation in Reactor Building				
Operating Floor	1/s	1/3 mo	1/3 mo	Using gamma source for
Ventilation Exhaust	1/s	1/3 mo	1/3 mo	calibration
15. High Radiation on Air Ejector Off-Gas		1/3 mo	1/3 mo	Using built-in calibration equipment
	1/s			Channel Check
	1/mo			Source check
		1/24 mo		Calibration according to established station calibration procedures
			1/24 mo	Note a
16. IRM Level	N/A	Each startup	N/A	
IRM Scram	*	*	*	Using built-in calibration equipment
17. IRM Blocks	N/A	Prior to startup and shutdown	Prior to startup and shutdown	Upscale and downscale
18. Condenser Low Vacuum	N/A	1/20 mo	1/20 mo	
19. Manual Scram Buttons	N/A	N/A	1/3 mo	
20. High Temperature Main Steamline Tunnel	N/A	1/20 mo	Each refueling outage	Using heat source box

TABLE 4.1.1 (cont'd)

Instrument Channel	Check	Calibrate	Test	Remarks (Applies to Test and Calibration)
21. SRM	*	*	*	Using built-in calibration equipment
22. Isolation Condenser High Flow ΔP (Steam and Water)	N/A	1/3 mo	1/3 mo	By application of test pressure
23. Turbine Trip Scram	N/A	N/A	1/3 mo	
24. Generator Load Rejection Scram	N/A	1/3 mo	1/3 mo	
25. Recirculation Loop Flow	N/A	1/20 mo	N/A	By application of test pressure
26. Low Reactor Pressure Core Spray Valve Permissive	N/A	1/3 mo	1/3 mo	By application of test pressure
27. Scram Discharge Volume (Rod Block)				
a) Water level high	N/A	Each refueling outage	1/3 mo	Calibrate by varying level in sensor column
b) Scram Trip bypass	N/A	N/A	Each refueling outage	
28. Loss of Power				
a) 4.16 KV Emergency Bus Undervoltage (Loss of voltage)	1/d	1/24 mo	1/mo	
b) 4.16 KV Emergency Bus Undervoltage (Degraded Voltage)	1/d	1/24 mo	1/mo	

TABLE 4.1.1 (cont'd)

Instrument Channel	Check	Calibrate	Test	Remarks (Applies to Test and Calibration)
29. Drywell High Radiation	N/A	Each re-fueling outage	Each re-fueling outage	
30. Automatic Scram Contactors	N/A	N/A	1/wk	Note 1

* Calibrate prior to startup and normal shutdown and thereafter check 1/s and test 1/wk until no longer required.

Legend: N/A = Not Applicable; 1/s = Once per shift; 1/d = Once per day; 1/3d = Once per 3 days; 1/wk = Once per week; 1/mo = Once per month; 1/3 mo = Once every 3 months; 1/20 mo = Once every 20 months; 1/24 mo = Once every 24 months

NOTE 1: Each automatic scram contactor is required to be tested at least once per week. When not tested by other means, the weekly test can be performed by using the subchannel test switches.

NOTE 2: At least daily during reactor POWER OPERATION, the reactor neutron flux peaking factor shall be estimated and flow-referenced APRM scram and rod block settings shall be adjusted, if necessary, as specified in Section 2.3 Specifications A.1 and A.2.

NOTE 3: Calibrate electronic bistable trips by injection of an external test current once per 3 months. Calibrate transmitters by application of test pressure once per 12 months.

The following notes are only for Item 15 of Table 4.1.1:

A channel may be taken out of service for the purpose of a check, calibration, test or maintenance without declaring the channel to be inoperable.

a. The Channel Test shall also demonstrate that control room alarm annunciation occurs if any of the following conditions exists:

1) Instrument indicates measured levels above the alarm setpoint.
2) Instrument indicates a downscale failure.
3) Instrument controls not set in operate mode.
4) Instrument electrical power loss.

TABLE 4.1.2

MINIMUM TEST FREQUENCIES FOR TRIP SYSTEMS

Trip System	Minimum Test Frequency
1) Dual Channel (Scram)	Same as for respective instrumentation in Table 4.1.1
2) Rod Block	Same as for respective instrumentation in Table 4.1.1
3) DELETED	DELETED
4) Automatic Depressurization each trip system, one at a time	Each refueling outage
5) MSIV Closure, each closure logic circuit independently (1 valve at a time)	Each refueling outage
6) Core Spray, each trip system, one at a time	1/3 mo and each refueling outage
7) Primary Containment Isolation, each closure circuit independently (1 valve at a time)	Each refueling outage
8) Refueling Interlocks	Prior to each refueling operation
9) Isolation Condenser Actuation and Isolation, each trip circuit independently (1 valve at a time)	Each refueling outage
10) Reactor Building Isolation and SGTS Initiation	Same as for respective instrumentation in Table 4.1.1
11) Condenser Vacuum Pump Isolation	Prior to each startup
12) Air Ejector Offgas Line Isolation	Each refueling outage
13) Containment Vent and Purge Isolation	1/20 mo

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO.171

TO FACILITY OPERATING LICENSE NO. DPR-16

GPU NUCLEAR CORPORATION AND

JERSEY CENTRAL POWER & LIGHT COMPANY

OYSTER CREEK NUCLEAR GENERATING STATION

DOCKET NO. 50-219

1.0 INTRODUCTION

The BWR Owners Group (BWROG), of which GPU Nuclear Corporation (GPUN/the licensee) is a member, sponsored studies by General Electric (GE) to apply probabilistic analytical methods in order to justify an increase in surveillance test intervals (STIs) and allowable out-of-service times (AOTs) for various BWR instrumentation. All proposed STI and AOT changes in accordance with these studies resulted in a series of GE Licensing Topical Reports (LTRs) which have been previously reviewed and approved by the NRC staff. Also, AOTs are clarified in accordance with the most recently approved BWR Owners Group letters which were used in the development of NUREG-1433 "Standard Technical Specification, General Electric Plants, BWR/4." The Technical Specification (TS) changes will permit specified Channel Tests to be conducted quarterly rather than weekly or monthly. However, the approval was conditional based on a list of plant-specific conditions that the licensees should follow.

By letter dated May 12, 1994, as supplemented September 2, 1994, the licensee proposed to revise the TS requirements regarding STIs (Table 4.1.1) and AOTs (Table 3.1.1) for Reactor Protection System (RPS), Emergency Core Cooling System (ECCS) Actuation, Isolation Actuation and Control Rod Block Instrumentation in accordance with the GE LTRs. The proposed AOT and STI changes are based on the most recently approved BWR Owners Group letters which were used in establishing AOTs and STIs for the new Standard Technical Specifications, (NUREG-1433). Technical changes regarding Channel Calibration requirements for Average Power Range Monitor (APRM) Scram, High Drywell Pressure (for Core Cooling) and Turbine Trip Scram instrumentation are also proposed. Editorial changes are proposed to correct and clarify TS. The licensee also provided information regarding required plant-specific evaluation contained in reports MDE-98-0485, "Technical Specification Improvement Analysis for the Reactor Protection System for Oyster Creek Nuclear Generating Station" dated July 1985 and RE-004, "Technical Specification Improvement Analysis for Emergency Core Cooling System Actuation

Instrumentation for Oyster Creek Nuclear Generating Station" dated January 1987. The September 2, 1994, letter provided clarifying information that did not change the initial proposed no significant hazards consideration determination.

2.0 DISCUSSION AND EVALUATION

The proposed changes reflect Standard Technical Specification (STS) revisions contained in the LTRs which, based upon reliability analyses, support increases in STIs and AOTs for surveillance and repair. These changes are beneficial in reducing: (i) potential unnecessary plant scrams, (ii) excessive equipment test cycles, and (iii) the diversion of personnel and resources for unnecessary testing. The NRC staff has reviewed and approved these LTRs in Safety Evaluation Reports (SERs). Subsequently, all the LTRs were issued with the corresponding SERs included.

The Oyster Creek Technical Specification requirements regarding STIs (Table 4.1.1) and AOTs (Table 3.1.1) are to be revised for Reactor Protection System (RPS), Emergency Core Cooling System (ECCS) Actuation, Isolation Actuation and Control Rod Block Instrumentation in accordance with the following GE LTRs:

(1) NEDC-30851P-A "Technical Specification Improvement Analyses for BWR Reactor Protection System," dated March 1988

(2) NEDC-30936P-A (Parts 1 and 2) "BWR Owners Group Technical Specification Improvement Methodology (With Demonstration for BWR ECCS Actuation Instrumentation)," dated December 1988

(3) NEDC-30851P-A (Supplement 2) "Technical Specification Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," dated March 1989

(4) NEDC-31677P-A "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," dated July 1990

(5) NEDC-30851P-A (Supplement 1) "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," dated October 1988

(6) GENE-770-06-1-A "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," dated December 1992.

2.1 AOT AND STI CHANGES

The AOT and STI changes to Oyster Creek TS grouped under the applicable topical reports are as follows:

NEDC-30851P-A dated March 1988/MDE-98-0485, Rev. 1 dated July 1985

(1) Table 3.1.1, Section A.2-A.12 and Table Notes - Note nn is added which provides allowable out-of-service times for repair for the specified scram parameters. Note nn is clarified in accordance with BWROG letter 92102 from C. L. Tully (GE) to B. K. Grimes (NRC), "BWR Owners Group (BWROG) Topical Reports on Technical Specification Improvement Analysis for BWR Reactor Protection Systems - Use for Relay and Solid State Plants (NEDC-30884 and NEDC-30851P)," dated November 4, 1992. Note nn will apply to the following scram parameters:

a. High Reactor Pressure - Parameter 2
b. High Drywell Pressure - Parameter 3
c. Low Reactor Water Level - Parameter 4
d. High Water Level in Scram Discharge Volume - Parameter 5.a & 5.b
e. Low Condenser Vacuum - Parameter 6
f. High Radiation in Main Steamline Tunnel - Parameter 7
g. Average Power Range Monitor - Parameter 8
h. Intermediate Range Monitor (IRM) - Parameter 9
i. Main Steamline Isolation Valve Closure - Parameter 10
j. Turbine Trip Scram - Parameter 11
k. Generator Load Rejection Scram - Parameter 12

(2) Table 3.1.1, Note c - Note c is revised to allow any one APRM to be removed from service for up to 6 hours for surveillance without tripping its trip system.

(3) Table 4.1.1, Instrument Channel Nos. 1 (Scram Function), 2, 3, 5.b, 11 (APRM Scram Trips) and 13.a - The Channel Test interval is revised to quarterly from weekly or monthly for the scram instrumentation identified below:

a. High Reactor Pressure - Instrument Channel 1
b. High Drywell Pressure (Scram) - Instrument Channel 2
c. Low Reactor Water Level - Instrument Channel 3
d. High Water Level in Scram Discharge Volume - Instrument Channel 5.b (analog)
e. APRM Scram Trips - Instrument Channel 11
f. High Radiation in Main Steamline - Instrument Channel 13.a

(4) Table 4.1.1, Instrument Channel No. 30 and NOTE 1 - This is a new requirement added to ensure that the automatic scram contactors are tested on a weekly basis. The test of the automatic scram contactors using the subchannel test switches does not have to be performed at each weekly interval if the automatic scram contactors are tested by other means, i.e., by performance of a different required Channel Calibration as discussed below in Item (12) and replaced with the note concerning the weekly test of the automatic scram contactors.

NEDC-30936P-A, (Parts 1 and 2) dated December 1988/RE-004 dated January 1987

(5) Table 3.1.1, Sections C.1-2, D.1-3, G.1-3 and Table Notes - Note pp is added providing an allowable out-of-service time for repair for the specified parameters as identified below:

a. ISOLATION CONDENSER INITIATION (Section C)
   1) High Reactor Pressure - Parameter 1
   2) Low-Low Reactor Water Level - Parameter 2

b. CORE SPRAY INITIATION (Section D)
   1) Low-Low Reactor Water Level - Parameter 1
   2) High Drywell Pressure - Parameter 2
   3) Low Reactor Pressure (valve permissive) - Parameter 3

c. AUTOMATIC DEPRESSURIZATION (Section G)
   1) High Drywell Pressure - Parameter 1
   2) Low-Low-Low Reactor Water Level - Parameter 2
   3) AC Voltage - Parameter 3

(6) Table 4.1.1, Instrument Channel Nos. 1 (Isolation Condenser Actuation Function), 4 (Isolation Condenser Actuation and Core Spray Actuation Functions), 6 and 9 (Core Spray Actuation and Automatic Depressurization Actuation Functions) - The Channel Test interval is revised to quarterly from monthly for the ECCS Actuation instrumentation indicated below:

a. High Reactor Pressure - Instrument Channel 1
b. Low-Low Water Level - Instrument Channel 4
c. Low-Low-Low Water Level - Instrument Channel 6
d. High Drywell Pressure (Core Cooling) - Instrument Channel 9

NEDC-30851P-A, Supplement 2 dated March 1989/NEDC-31677P-A dated July 1990

(7) Table 3.1.1, Sections B.1-6, F.1-2, H.1-2 and L and Table Notes - Note oo is added which provides allowable out-of-service times for repair for the specified isolation actuation parameters. Note oo is clarified in accordance with GE letter OG90-579-32A from W. P. Sullivan and J. F. Klapproth (GE) to M. L. Wohl (NRC), "Implementation Enhancements to Technical Specification Changes Given in Isolation Actuation Instrumentation Analysis," dated June 25, 1990. Note oo will apply to the following isolation actuation instrumentation:

a. REACTOR ISOLATION (Section B)
   1) Low-Low Reactor Water Level - Parameter 1
   2) High Flow in Main Steamline A - Parameter 2
   3) High Flow in Main Steamline B - Parameter 3
   4) High Temperature in Main Steamline Tunnel - Parameter 4
   5) Low Pressure in Main Steamline - Parameter 5
   6) High Radiation in Main Steamline Tunnel - Parameter 6

b. PRIMARY CONTAINMENT ISOLATION (Section F)
   1) High Drywell Pressure - Parameter 1
   2) Low-Low Reactor Water Level - Parameter 2

c. ISOLATION CONDENSER ISOLATION (Section H)
   1) High Flow Steam Line - Parameter 1
   2) High Flow Condensate Line - Parameter 2

d. CONDENSER VACUUM PUMP ISOLATION (Section L)
   1) High Radiation in Main Steamline Tunnel - Parameter 1

(8) Table 4.1.1, Instrument Channel Nos. 2 (Primary Containment Isolation Function Common to Scram), 4 (Reactor Isolation and Primary Containment Isolation Functions Common to ECCS), 7, 8, 13a (Reactor Isolation and Condenser Vacuum Pump Isolation Functions Common to Scram), 14 and 15 - The Channel Test interval is revised to quarterly from weekly or monthly for the following isolation actuation instrumentation:

a. High Drywell Pressure (Scram) - Instrument Channel 2
b. Low-Low Water Level - Instrument Channel 4
c. High Flow in Main Steamline - Instrument Channel 7
d. Low Pressure in Main Steamline - Instrument Channel 8
e. High Radiation in Main Steamline - Instrument Channel 13.a
f. High Radiation in Reactor Building - Instrument Channel 14
g. High Radiation on Air Ejector Off-Gas - Instrument Channel 15

<u>NEDC-30851P-A, Supplement 1 dated October 1988/GENE-770-06-1-A dated December 1992</u>

(9) Table 4.1.1, Instrument Channel No. 12 - The Channel Test frequency is revised to quarterly from monthly for the Control Rod Block instrumentation below:

a. APRM Rod Blocks - Instrument Channel 12

TECHNICAL CHANGES (GLOBAL)

(10) Sections 3.1 and 4.1, Bases - The bases for the two TS Instrumentation sections are revised to reflect the GE LTRs as the basis for AOT and STI changes and will be included as references.

(11) Table 3.1.1, Global Note* - This note, which appears at the end of the table and just before the indicated Notes section, describes the Action Required column and provides an allowed out-of-service time for performing surveillance. The note is revised to allow 6 hours instead of 2 hours for surveillance of instrument channels provided at least one operable channel in the same trip system is monitoring the parameter. The 6 hour allowance is supported by the LTRs for all instrumentation in Table 3.1.1 except the Diesel Generator Load Sequence Timers and Loss of Power instruments. Note kk was established for this instrumentation and retains the 2 hour allowance.

(12) Table 4.1.1, NOTE 1 and Figure 4.1.1 - Current NOTE 1 and Figure 4.1.1 are deleted since surveillance intervals will be based on the reliability analyses contained in the GE LTRs and not on the methodology described in the current TS bases which uses Figure 4.1.1 which allows surveillance Channel Test intervals to be adjusted between monthly and quarterly. The licensee has not used this method of adjusting Channel Test intervals.

2.2 CHANNEL CALIBRATION INTERVAL CHANGE

The channel calibration interval changes proposed to the Oyster Creek TS are as follows:

(1) Table 4.1.1, Instrument Channel 11 (APRM Scram Trips) - The Channel Calibration interval for the APRM Scram Trips is currently weekly. This interval is the same as the current Channel Test interval. The change of the Channel Test interval to quarterly is proposed and supported by the LTRs. Accordingly, an extension of the Channel Calibration Test interval to quarterly is appropriate. The licensee has demonstrated that drift data of the affected instrumentation remained within the existing allowance in the instrument setpoint calculation when considered over the extended period.

(2) Table 4.1.1, Instrument Channels 9 (High Drywell Pressure for Core Cooling) and 23 (Turbine Trip Scram) - A quarterly Channel Calibration interval is added for instrument channels 9 and 23. Currently, a Channel Calibration interval is not specified for the High Drywell Pressure instruments. Since they are calibrated on a quarterly interval, it is appropriate to include this surveillance requirement in the TS. Also, the Channel Calibration interval is not specified for instrument channel 23. Since this trip parameter senses turbine stop valve position via limit switches and its switch adjustment methods are similar to Main Steamline Isolation Valve Scram instrumentation (Instrument Channel 10), it is appropriate to include this surveillance requirement in the TS.

2.3 EDITORIAL CHANGES

The editorial changes proposed to the Oyster Creek TS are as follows:

(1) Capitalization of Definitions - In Sections 3.1 and 4.1, the definitions, where they appear in specifications, bases, tables and table notes, are capitalized to highlight the fact they are terms with specific meanings. This is consistent with STS convention. The definitions are contained in TS Section 1.0.

(2) Table 3.1.1 Heading - The table column which currently reads Min. No. of Instrument Channels Per Operable Trip Systems is incorrect in that the word Systems should not be plural. A separate column specifies the required number of Trip Systems. The subject column specifies the number of instrument channels for each Trip System and, therefore, the word System in this column is properly singular.

(3) Table 3.1.1, Sections A.7, B.6 and L.1 - Minor grammatical changes are made to ensure that this instrumentation (High Radiation in Main Steamline Tunnel) is consistently identified where it appears in its functions of scram (Section A.7) and isolation (Sections B.6 and L.1). Since this instrumentation is common to both scram and isolation functions, it needs to be consistently displayed to preclude confusion when new Note oo to Table 3.1.1 is applied.

(4) Table 3.1.1, Section C - The word "plant" is deleted from the Action Required since it is superfluous. This allows the Action Required to refer directly to the TS definition for PLACE IN COLD SHUTDOWN CONDITION. Also, in order to clarify the function achieved, the heading is revised to Isolation Condenser "Initiation".

(5) Table 3.1.1, Section C.2 - The word "level" is added to the C.2 description of the Isolation Condenser Initiation variable on Low-Low Reactor Water Level. This is for clarification purposes and makes this description consistent with other reactor water level instrument descriptions in the table.

(6) Table 3.1.1, Section D - The description of the function in this section is clarified to indicate that instrumentation under Section D initiates Core Spray. Therefore, the function description is revised to read Core Spray Initiation.

(7) Table 3.1.1, Section J.1 - The requirement for operability in the Startup mode was inadvertently omitted in License Amendment 72. The table is revised to restore that omission.

(8) Table 3.1.1, Section J.4, Notes and Associated Footnote - Note gg is deleted since it concerns a 1985 licensing condition which is no longer in effect. This note expired at the end of the Cycle mid-10 outage. Oyster Creek is currently operating in Cycle 14.

(9) Table 3.1.1, Note t - A typographical error in this note currently allows sensors to be "...operable or bypassed...". The note should correctly read "...inoperable or bypassed..." since this note would be unnecessary to allow operability. This clarifies that Core Spray instrumentation operability is not required if its associated and supported Core Spray System is inoperable.

(10) Table 3.1.1, Note y - All references to Note y in Table 3.1.1 were deleted by License Amendment 75. This note is no longer applicable and is deleted.

(11) Table 3.1.1, Sections M.1, M.2, M.3, N.a and b and Table Notes - Note kk is added to indicate that the allowable out-of-service time for surveillance of the Diesel Generator Load Sequence Timers and Loss of Power instrumentation does not change and remains 2 hours. The GE LTRs do not address this instrumentation. In addition, Section M.3 is revised to clarify that the load sequence timer is associated with the Reactor Building Closed Cooling Water Pumps.

(12) Section 4.1, Specification - A minor editorial change to Specification revises "...as per definitions ..." to "...using the definitions... ." This change does not alter the meaning or intent of the Specification and is purely grammatical.

(13) Table 4.1.1, NOTE 2 - This note refers to "...Section 2.3 Specifications (1) (a) and (2) (a)... ." These specifications are not currently identified in this fashion. The correct identification of these specifications is "...A.1 and A.2..." and NOTE 2 is revised accordingly. This change is a correction and ensures consistency between NOTE 2 and Section 2.3.

(14) Table 4.1.1, Instrument Channels 18, 20 and 25 - The surveillance interval is currently displayed as "1/20" which means once every 20 months. This is revised to 1/20 mo to clarify that the interval is 20 months and to ensure consistency with the nomenclature used in Table 4.1.1.

(15) Table 4.1.1, Instrument Channels 23, 24 and 26 - The surveillance interval is currently indicated as "Every 3 months." Since the nomenclature used in Table 4.1.1 is 1/3 mo for this interval, the surveillance frequency description for the subject instrument channels is revised to conform with the nomenclature. This change does not alter the interval and is editorial.

(16) Table 4.1.1, Instrument Channels 28a and 28b - The Channel Check interval for these instrument channels is specified as "daily." The nomenclature indicated in the table legend shows "1/d" as the description of this interval. To ensure consistency, the Channel Check interval for the subject instrument channels is revised to conform with the legend. This change does not alter the interval and is editorial.

(17) Table 4.1.1, NOTES - The table notes are moved from the first page of the table to a more appropriate location at the end of the table.

(18) Table 4.1.1, Legend - The table legend establishes nomenclature used in Table 4.1.1 to specify surveillance intervals. The following definitions are added to the legend: 1/mo = Once per month, 1/20 mo = Once every 20 months, and 1/24 mo = Once every 24 months. In addition, the table legend defining the once every 18 month interval is deleted since this interval no longer appears in Table 4.1.1.

(19) Sections 3.1 and 4.1, Amendment Nos. on pages - As part of the pagination process for this change request, the previous license amendment numbers displayed on the bottom of each page (where applicable since not all pages have amendment numbers) have been revised to ensure that the numbers accurately reflect associated changes to the pages.

2.4 JUSTIFICATION FOR THE PROPOSED CHANGES

GPUN has determined that the generic analyses performed by GE for the BWR Owners Group for revised AOTs and STIs for RPS, ECCS Actuation, Isolation Actuation and Rod Block instrumentation are applicable to the Oyster Creek Nuclear Generating Station. GPUN has completed plant-specific evaluations required by the NRC SERs which approved the LTRs for use by individual facilities. As stated in the SERs, three issues must be addressed to apply the RPS LTR (NEDC-30851P-A) and two issues must be addressed to apply the other LTRs to an individual facility when specific TS are considered for revision. These issues, the licensee's treatment and the staff's evaluation of them are as follows:

(1) Confirm the applicability of the generic analyses to the specific facility

a. The generic study in NEDC-30851P-A provides a technical basis to modify the STIs and AOTs of the RPS. The generic study also provides additional analyses of different RPS configurations to support the application of the generic basis on a plant-specific basis. A plant-specific evaluation for modifying the STIs and AOTs of the RPS in the TS of Oyster Creek has been performed by GE and is contained in the plant-specific evaluation report MDE-98-0485, Technical Specification Improvement Analysis for the Reactor Protection System for Oyster Creek Nuclear Generating Station. The evaluation utilized the generic basis and additional analyses documented in LTR NEDC-30851P-A. The results indicated that the RPS configuration for Oyster Creek has several differences compared to the RPS configuration in the generic evaluation. The NRC staff has reviewed NEDC-30851P-A and MDE-98-0485 and verified that the generic analysis is applicable to Oyster Creek. The differences between the RPS at Oyster Creek and the generic plant analyzed in NEDC-30851P-A are discussed in (3) below.

b. GE Report NEDC-30936P-A provides an acceptable generic basis for supporting plant-specific TS changes that extend ECCS STIs and AOTs for test and repair. The plant-specific evaluation contained in GE Report RE-004, Technical Specification Improvement Analysis for the Emergency Core Cooling System Actuation Instrumentation for Oyster Creek Nuclear Generating Station, followed the procedures of NEDC-30936-A to identify and evaluate the differences between the Oyster Creek ECCS configuration and the ECCS configuration used in the generic analysis. The results of the staff review indicate that while the ECCS configuration for Oyster Creek has two minor discrepancies, the discrepancies and their impact do not affect the applicability of the TS changes developed by the generic efforts of these LTRs. Therefore, the generic analysis in NEDC-30936P-A is applicable to Oyster Creek.

c. LTR NEDC-30851P-A, Supplement 2, Appendix A identifies GPUN as a participant in the BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation evaluation. The staff reviewed the licensee's evaluation and verified that the generic analysis is applicable to Oyster Creek.

d. LTR NEDC-31677P-A, Appendix E identifies GPUN as a participant in the BWR Isolation Actuation Instrumentation evaluation. The staff reviewed the licensee's evaluation and verified that the generic analysis is applicable to Oyster Creek.

e. LTR NEDC-30851P-A, Supplement 1, Appendix B identifies GPUN as a participant in the BWR Control Rod Block Instrumentation evaluation. The staff reviewed the licensee's evaluation and verified that the generic analysis is applicable to Oyster Creek.

f. LTR GENE-770-06-1-A identifies the application of changes to STIs and AOTs for Selected Instrumentation Technical Specifications to all BWR plants. The staff reviewed the licensee's evaluation and verified that this LTR is applicable to Oyster Creek. This LTR was found applicable only to the limited extent that it identified AOTs for Control Rod Block Instrumentation which NEDC-30851P-A, Supplement 1 did not explicitly address.

(2) Demonstrate, by use of current drift information provided by the equipment vendor or plant-specific data, that the drift characteristics for instrumentation used in RPS, ECCS, Isolation and Rod Block instrument channels in the plant are bounded by the assumptions used in the LTRs when the functional test interval is extended from weekly or monthly to quarterly.

The staff generic SER of May 27, 1987 on GE LTR NEDC-30844 and NEDC-30851P states the NRC's requirement for confirmation of instrument setpoint drift allowance. By a letter to the BWR Owners Group from C. Rossi (NRC) dated April 27, 1988, the NRC requested licensees to confirm that the setpoint drift which could be expected under the extended STIs has been studied and either (i) has been shown to remain within the existing allowance in the RPS and ESFAS instrument setpoint calculation or (ii) that the allowance and setpoint have been adjusted to account for the additional expected drift. No additional information need to be provided for staff review. However, records showing the actual setpoint calculation and supporting data should be retained onsite for possible future staff audit. The licensee has demonstrated that drift data of the affected instrumentation remained within the existing allowance in the RPS and ESFAS instrument setpoint calculation when considered over the extended period.

(3) Confirm that the differences between the parts of the RPS that perform the trip functions in the plant and those of the base case plant were included in the plant-specific analysis done using the procedures of Appendix K of NEDC-30851P or present plant-specific analyses to demonstrate no appreciable change in RPS availability or public risk.

GE Report MDE-98-0485, Revision 1, "Technical Specification Improvement Analysis for the Reactor Protection System for Oyster Creek Nuclear Generating Station", provides a plant-specific evaluation to determine whether the generic study contained in LTR NEDC-30851P-A is applicable to Oyster Creek to review STIs and add AOTs in TS for the RPS instrumentation. This report utilizes the procedures in Appendix K of NEDC-30851P-A to identify and evaluate the differences between the parts of the RPS that perform the trip functions at Oyster Creek and those analyzed in the generic study. GPUN performed an evaluation of NEDC-30851P-A and MDE-98-0485 to verify that the generic analysis is applicable to Oyster Creek and concluded that it remains applicable with discrepancies addressed as follows:

a. MDE-98-0485, Appendix A, Section II, Part B.1 - This section lists the RPS sensors and identifies type, total number and number per RPS channel. The number given for MSIV position is 4 total and 1/RPS channel. The correct numbers are 8 total and 2/RPS channel. Oyster Creek has separate limit switches which initiate scram at 10% closure for each MSIV. The generic model contains four instrument channels per trip system as shown in NEDC-30851P-A, Table 7.4. With two sensors per channel and two channels per trip system, the number of sensors per trip system for MSIV position at Oyster Creek is four.

b. MDE-98-0485, Section 3, Item k; Appendix A, Section II, Part B.1 and Section III, Part B.1 - The plant-specific report indicates bistable switches are used to monitor reactor pressure and reactor water level. Subsequent to the preparation of the report, these sensors were replaced with analog trip units and transmitters. Therefore, there is no longer a difference between the generic model and Oyster Creek in this area.

c. MDE-98-0485, Appendix A, Section II, Parts C.3, D.1 and F.1 and Section III, Part D.1 - Oyster Creek uses GE Type CR205 automatic scram contactors while one GE Type CR205 and one GE Type CR305 are used for the manual scram contactors. The generic model used GE Type CR105 for automatic and manual scram contactors. There is no significant reliability effect because the common cause failure rate of GE Type CR105, CR205 and CR305 contactors are the same and the use of diverse contactor models tends to improve reliability for the manual scram function.

d. MDE-98-0485, Section 3, Item m; Appendix A, Section II, Part G.2 and Section III, Part G.1 - Calibration frequency requirements for analog trip units were incorporated into the TS. The quarterly calibration interval for analog trip units and annual calibration interval for transmitters is within the range of the sensitivity study documented in NEDC-30851P-A.

e. MDE-98-0485, Section 3, Item m; Appendix A, Section II, Parts G.4 and G.6 - Although Oyster Creek TS do not provide specific AOTs for the inoperable instrument channels or trip systems, the bases in TS 3.1 indicate that prompt action is taken to trip the channel or trip system to compensate for the inoperable condition when it involves one trip system. This is done immediately. However, when both trip systems are involved the Action Required in TS Table 3.1.1 is initiated immediately since tripping both scram systems will initiate a reactor trip which is undesirable.

f. MDE-98-0485, Section 3, Item 3; Appendix A, Section II, Part G.7 and Section III, Part G.1 - TS currently allow a channel to be inoperable for up to 2 hours for required surveillance without placing the trip system in the tripped condition. This has been changed from a 1-hour allowance and is the nominal original AOT for surveillance considered in NEDC-30851P-A.

g. MDE-98-0485, Appendix A, Section II, Part H.1 - Flux sensors, radiation sensors, and analog sensors (high reactor pressure, low reactor water level, low-low reactor water level, and high water level) are generally not included in the Channel Tests at Oyster Creek as instrument loop test switches provide the means for logic testing. These differences are consistent with the TS definition for Channel Test and have no effect with respect to the generic model since they are within the range of the sensitivity study performed in NEDC-30851P-A.

h. MDE-98-0485, Appendix A, Section II, Parts H.2 and H.3 - When an individual sensor channel is in repair, the logic channel is tripped, and if the individual sensor channel is in test, the sensor is temporarily inoperable but the logic channel is not necessarily tripped. These conditions are permitted by current TS and have no effect when comparing Oyster Creek to the generic model since they are within the range of the sensitivity study performed in NEDC-30851P-A.

i. Oyster Creek utilizes a High Recirculation Flow Scram which is not identified in MDE-98-0485. Two recirculation flow converters, one for each RPS trip system initiates a scram when recirculation flow exceeds the trip setpoint. This parameter does not serve as a scram sensor for any of the more severe initiating events as defined in NEDC-30851P-A and consequently the addition of another scram initiation signal will have no significant impact on RPS failure frequency. Elimination of this scram parameter would have no effect on the Oyster Creek relationship to the generic model.

j. MDE-98-0485, Section 3, Item p; Appendix A, Section II, Part H.4 and Section III, Part G.2 - The number of scram contactor actuations currently experienced during Channel Tests at Oyster Creek differs from those assumed in the generic model and identified in the plant-specific report. The differences are described as follows:

   1) APRM Channel Test results in 6 actuations per scram contactor in each automatic trip logic channel

   2) MSIV Closure Channel Test causes 2 actuations per scram contactor in each automatic trip logic channel

   3) Turbine Control Valve fast closure Channel Test consists of 2 actuations per scram contactor in each automatic trip logic channel since the ≤40% power Turbine trip Scram Bypass switches are also tested during this surveillance

   4) The High Recirculation Flow Scram test is performed quarterly and consists of 2 actuations per scram contactor in each automatic trip logic channel

   5) IRM Front Panel test is performed weekly and initiates 2 actuations per scram contactor in each automatic trip logic channel whenever the reactor is not in the RUN MODE.

   The above differences have no significant effect since they remain within the range of the sensitivity study performed in NEDC-30851P-A. The total number of automatic scram contactor actuations is estimated to be approximately 406 actuations per contactor per year. This exceeds the estimate in NEDC-30851P-A of 272±65 actuations per year but has no significant impact on RPS reliability.

k. The backup scram valves are de-energized to trip. There is no significant effect on RPS reliability caused by this because the operation of the backup scram valves is controlled by the scram contactors.

The differences between the RPS at Oyster Creek and the generic model are bounded by the analysis contained in the RPS LTR (NEDC-30851P-A). As discussed in the above, the staff concludes that the generic analysis remains applicable to Oyster Creek.

2.4 SUMMARY

The proposed changes extend STIs and AOTs for instrumentation and have been justified using probabilistic analytical methods. The affected instrumentation is associated with the RPS, ECCS, Isolation Actuation and Control Rod Block Instrumentation. The changes have been the subject of generic Licensing Topical Reports which the NRC has reviewed and approved. GPU Nuclear has addressed the implementation of the generic Technical Specification changes identified in the LTRs on a plant-specific basis. The staff has reviewed the LTRs and the plant-specific reports and concludes that the generic analyses are applicable to Oyster Creek. The changes also include editorial changes which are corrections to ensure consistent use of nomenclature, correction of typographical errors, reformatting of the instrumentation tables, and deletion of a note which is no longer applicable. The licensee performed the required plant-specific analysis and justified the application of generic analysis to the Oyster Creek plant-specific design. The information for setpoint drift supports the conclusion that instrument drift is not a concern in extending the functional test interval from monthly to quarterly. Therefore, the staff has found the proposed changes to the Oyster Creek Technical Specifications acceptable.

3.0 STATE CONSULTATION

In accordance with the Commission's regulations, the New Jersey State official was notified of the proposed issuance of the amendment. The State official had no comments.

4.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes surveillance requirements. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding (59 FR 32228). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

5.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

Principal Contributor: S. Rhow

Date: October 11, 1994