INL/EXT-12-27205

Design to Achieve Fault Tolerance and Resilience

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Gregg Swindlehurst, GS Nuclear Consulting, LLC

September 2012

The INL is a U.S. Department of Energy National Laboratory operated by Battelle Energy Alliance

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Prepared for the
U.S. Department of Energy
Office of Nuclear Energy
Under DOE Idaho Operations Office
Contract DE-AC07-05ID14517

Executive Summary

There are significant opportunities to improve nuclear power plant response to major transients by increasing the level of automation in control systems. The intent is to reduce dependence on operator actions in time-critical, complex responses to plant upsets and to make control systems more robust in their ability to manage non-steady state conditions. This report provides initial scoping for follow-on work designed to improve plant response in these areas.

The focus of this report is twofold. Selected reactor trips over the last five years are examined to determine if there are potential opportunities to automate tasks that are currently performed manually. The second area is to evaluate the potential for avoiding reactor trips by reducing power in a controlled manner upon the loss of turbine generator load.

Some candidate opportunities to reduce the frequency of reactor trips identified in this report are redundant feedwater controls, automated response to a feedwater or condensate pump trip, rapidly reducing power to avoid a reactor trip, and elimination of air operators for the feedwater control valves or providing redundant air supplies for these valves.

Redundant Feedwater Control

The feedwater control system was identified as a cause of 27 reactor trips over the evaluation period. Twenty-three of those trips were due to a problem related to the electronic control system. A redundant electronic control system for each feedwater control valve offers a means for avoiding the majority (if not all) of the reactor trips from this cause. Some nuclear units have implemented redundant feedwater control.

Improved Feedwater Regulating Valve Operators

Most feedwater control valves utilize an air operator to position the valve. This requires an air supply, a pressure regulator, a current to pressure converter, and the air operator. These air components caused 8 trips over the evaluation period. A potential improvement is to replace the air components with an electric valve positioner. An electric positioner equipped with redundant power sources and electronic controls has the potential to significantly reduce trips caused by feedwater regulating valve air operator issues. Another possibility is to provide redundant air supply components with an automatic switchover when signal and air pressure do not match.

Improved Feedwater Pump Turbine Control

Similar to the opportunities to improve feedwater valve control, implementation of redundant electronic feedwater pump turbine control and/or electric governor valve positioning has the potential for reducing nuclear unit trips.

Automated Response to Feedwater Pump Trip

An alternative (or complement) to changes to the feedwater turbine controls is to automate the response of the feedwater system to a feedwater pump trip. An integrated feedwater control system that can automatically lower power (turbine runback for Pressure Water Reactors [PWR]s, recirculation pump runback for Boiling Water Reactors [BWR]s) could prevent the number of scrams from this group.

Reduction of Spurious Reactor Protection System Trips

After feedwater events, trips of the reactor protection system account for the most reactor trips over the evaluation period. Since reactor protection systems are not control systems, automation is not a prime option to reduce trips. The overwhelming majority of the reactor protection system (RPS) trips occurred during maintenance or testing. Utilizing probabilistic risk assessment tools, it may be possible to significantly increase the required surveillance test intervals for reactor protection systems. Of the 16 trips associated with reactor protection systems, 5 occurred due to a pre-existing unknown half trip condition. It may be possible to install an automatic indication of a half trip condition so that the failed component could be repaired prior to performing a trip test on an alternate channel.

The three control functions that must perform correctly for a plant to handle a load rejection are the rod control system (or the [reactor power cutback system [RPCS] for those Combustion Engineering [CE] design that have installed it), the steam dump system, and the pressurizer pressure control systems. Only certain plants can survive a full load rejection. There are several potential control modifications that would improve the capability to quickly recover from a loss of load event.

Fast Reduction of Reactor Power

The RPCS (partial reactor trip) design employed in the CE design would significantly improve the capability to survive load rejections in the other designs, provided that sufficient steam dump capacity exists. Without the power cutback feature a design change to increase the reactivity insertion rate (faster rod insertion speed and/or higher differential control rod worth) would improve the plant response to load rejections.

Optimization of the Steam Dump System

Optimization of the steam dump system may also be possible, such as designing an anticipatory strategy focused on load rejection capacity rather than simple secondary pressure control or simple primary temperature control.

Optimization of the Feedwater Control System

Optimization of the feedwater control system may be possible, such that feedwater pump speed and control valve position, and the resulting steam generator inventory, would be better matched to the reactor heat generation during the reactor runback. This would assist in preventing a reactor trip on high pressure, and would also prevent a reactor trip on the trip functions that protect the fuel from departure from nucleate boiling (DNB).

Optimization of Westinghouse Set points

For the Westinghouse plants the turbine/reactor trip setpoint on loss of load could be optimized based on the time-in-cycle (by incorporating the moderator temperature coefficient (MTC) variation into the design), and with consideration for the end-of-cycle T-ave reduction (or reduced T-ave operation). Other optimizations of the over-power ΔT and over-temperature ΔT trip set points may be possible for Westinghouse plants.

Increased Steam Dump Capacity

Additional steam dump capacity would improve the capability to handle load rejections for all designs (except for those with 100% capacity). These refinements would include actual plant performance parameters for structure systems component (SSC)s such as steam dump valve capacity and valve stroke times.

Increased RCS Pressure Reduction Capability

Additional pressurizer spray or power operated relief valve (PORV) capacity would also be an improvement for designs that are limited by the high reactor pressure trip. Refinements in the analysis inputs related to mechanical systems may also provide an opportunity to justify optimizing the set points to enable allow large load rejections.

Acronyms

1E 4KV	Safety-Related High Voltage Supply System
ABWR	Advanced Boiling Water Reactor
ADV	Atmospheric Dump Valve
AOO	Anticipated Operational Occurrence
B&W	Babcock & Wilcox
BWR	Boiling Water Reactor
CE	Combustion Engineering
CFM	Centerline Fuel Melting
Condensate	Condensate Supply to the Main Feedwater Pump Suction
CPC	Core Protection Calculator
CPR	Critical Power Ratio
DNB	Departure from Nucleate Boiling
DNBR	Minimum Departure-From-Nucleate Boiling Ratio
EHC	Electro-Hydraulic Control System for the Main Turbine
ESFAS	Engineered Safety Features Actuation System
FRV	Feedwater Regulating Valve
FWCS	Feedwater Control System
FWP	Main Feedwater Pump including integral support equipment such as mini-flow
FWPT	Main Feedwater Pump Turbine
ICS	Integrated Control System
LOOP	Loss-of-Offsite Power
MTC	Moderator temperature coefficient

Non-1E 4KV	Non-safety related high voltage supply system
NRC	U. S. Nuclear Regulatory Commission
PORV	Power Operated Relief Valve
PRA	Probability Risk Assessment
PWR	Pressurized Water Reactor
RCS	Reactor Coolant System
RFCS	Recirculation Flow Control System
Rod Control	Rod Control System
RPCS	Reactor Power Cutback System
RPM	Rotations per Minute
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
Rx Recirc	Reactor Recirculation System (BWR)
SAFDL	Specified Acceptable Fuel Design Limit
SBPCS	Steam Bypass and Pressure Control System
SCWS	Stator Cooling Water System
SSC	Structure Systems Component
TMI	Three Mile Island
TPS	Turbine Protection System
Turbine	Main Turbine Generator
UFSAR	Updated Final Safety Analysis Report

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1. Introduction

There are significant opportunities to improve nuclear power plant response to major transients by increasing the level of automation in control systems. The intent is to reduce dependence on operator actions in time-critical, complex responses to plant upsets and to make control systems more robust in their ability to manage non-steady state conditions. This report provides initial scoping for follow-on work designed to improve plant response in these areas.

The focus of this report is twofold. Selected trips over the last five years are examined to determine if there are potential opportunities to automate tasks that are currently performed manually. The second area is to evaluate the potential for avoiding reactor trips by reducing power in a controlled manner upon the loss of turbine generator load.

The first area of potential improvement is to automate certain tasks currently performed manually by plant operators in response to off normal conditions such as plant transients or equipment failures. The objective is to improve the ability of nuclear units to remain online during upset conditions and to reduce error-likely situations involved with manual operator actions under stressful conditions.

The Nuclear Regulatory Commission (NRC) licensee event reports were searched for reactor scrams which occurred between January 1, 2007 and July 1, 2012 in which at least one of the following conditions was true and it appeared that a better designed system or process may have prevented the reactor scram:

- Maintenance or testing was in progress on any sort of control system that caused the reactor scram.
- Operators took manual control of a normally automatically controlled system and were unable to adequately control the system which resulted in a reactor scram.
- An automatically controlled system failed causing a reactor scram, but sufficient equipment remained in service that it may have been possible to remain online if the system could handle the perturbation.

The second area explores the issues and possible approaches for improving the capability of the current operating nuclear fleet to successfully run back to house load following a loss-of-load or load rejection event. A successful runback avoids tripping the reactor and the subsequent down-time of approximately two days before the unit can be back in service and providing power to the grid. It is desired for the unit to be reconnected to the grid rapidly following the runback to prevent minor grid disturbances from expanding into major grid disturbances like the grid collapse of 2003.

The current operating nuclear fleet has varying capabilities to successfully run back to house loads following load rejection events. Some designs are already fully capable, and other designs would require significant designs changes to reach an equivalent capability. The design features that enhance or limit that capability are identified, and the opportunities to modify the plant designs to achieve the desired load rejection capability are discussed. A primary issue is to determine any impact on nuclear safety, which involves performing analyses to evaluate the impact of any proposed design changes on the regulatory requirements established by the U.S. NRC. The cost of designing and installing the design changes, performing the required analyses, and obtaining NRC approval, would then need to be evaluated against the benefit of the increased capability to handle a load rejection and avoid contributing to major grid disturbances.

2. Task 1: Survey of U.S. Commercial Reactor Experience

The purpose of this section of the report is to provide initial scoping for follow on work designed to improve nuclear plant operation. The focus of the improvement is to automate certain tasks currently performed manually by plant operators in response to off normal conditions such as plant transients or equipment failures. The objective is to improve the ability of nuclear units to remain online during upset conditions and to reduce error-likely situations involved with manual operator actions under stressful conditions.

The NRC licensee event reports were searched for reactor scrams which occurred between January 1, 2007 and July 1, 2012 in which at least one of the following conditions was true and it appeared that a better designed system or process may have prevented the reactor scram:

- Maintenance or testing was in progress on any sort of control system that caused the reactor scram.
- Operators took manual control of a normally automatically controlled system and were unable to adequately control the system which resulted in a reactor scram.
- An automatically controlled system failed causing a reactor scram, but sufficient equipment remained in service that it may have been possible to remain online if the system could handle the perturbation.

Table 2-1 provides a summary of the reactor trips that met the above criteria.

Table 2-1 Summary of Reactor Trips 2007 - July 2012

Category	Events
Reactor trips, 2007 to July 2012	383
Reactor trips that met criteria	96
Manual reactor trip	40
Power decrease >50%	84
Power decrease >10%, <50%	12
Maintenance or testing was being performed which causes trip?	45
Operators took manual control of an automatically controlled system?	41

Appendix A, Table A-1, provides a list of the licensee event reports (LER) and the cause evaluation from the LER. Over the five year period, there were 383 reactor trip events. Ninety-six (96) of those events met one of the above listed criteria.

The systems (and in some cases the sub-system) that caused the 96 trips were identified as follows. The purpose of this type of breakdown is to facilitate development of potential solutions to trips.

1E 4KV	Safety related high voltage supply system
Condensate	Condensate supply to the main feedwater pump suction
CVCS	Chemical and volume control system
EHC	Electro-hydraulic control system for the main turbine
ESFAS	Engineered Safety Features Actuation System
FRV	Feedwater regulating valve
FWCS	Feedwater Control System
FWP	Main feedwater pump including integral support equipment such as mini-flow
FWPT	Main feedwater pump turbine
HDLC	Heater Drain Level Control System
Non-1E 4KV	Non-safety related high voltage supply system
Rod Control	Rod control system
RPS	Reactor Protection System
Rx Recirc	Reactor Recirculation System (BWR)
SCWS	Stator Cooling Water System
TPS	Turbine Protection System
Turbine	Main Turbine Generator

For each of the failures, the cause of the failure was categorized according to the following.

Air	A component in the air supply failed.
Design	A design failure was the direct cause of the trip.
Electronic	An electronic component failed that caused the trip.
Error	An error on the part of a technician or operator caused the trip.
Hyd	A component in the hydraulic supply failed.
Motor	A motor failed.
Procedure	An error in a procedure directly resulted in a trip.
Pump	A pump or component integral to the pump failed.
Relay	A relay failed.
Valve	A valve failed.

2.1 Frequent Operating Transients Caused by Equipment Faults and At-Power Maintenance or Testing

Table 2-2 provides a matrix of the systems/subsystems and the causes. The six leading systems that were the source of trips are as follows.

FWCS	Feedwater Control Systems were the source for 26 of the 96 reactor trips evaluated (27%). Of the 26 trips, 22 were caused by a failure in an electronic component, 3 were caused by a technician or operator error, and 1 was attributed to the system design. A review of the LERs showed that the operators attempted (or were in) manual control of the feedwater flow for 16 of the trips. There was no manual control of feedwater identified in 10 of the trip events.
RPS	Reactor Protection Systems were the source of 16 reactor trips. Of the 16 trips, 7 were caused by the failure of an electronic component failure, 5 were caused by a technician or operator error, 2 were caused by a procedural error, 1 due to a relay failure, and 1 by the system design. Table 2-5 lists the causes of the reactor protection system trips. Eight of the trips were caused by a component failure coupled with a surveillance test that placed the channel under test in the tripped condition.
FWPT	A main feedwater pump turbines (including reactor feedwater pump turbines) were the source of 11 trips. Of the 11 trips, 4 were caused by electronic component failures, 2 were caused by a hydraulic component failure, 2 were caused by a technician or operator error, 2 by valve failures, and one due to a lube oil pump failure.
FRV	Feedwater regulating valves were also the source of 10 trips. Of the 10 trips, 8 were caused by an air supply component failure, 1 was caused by a technician or operator error, and 1 was caused by a procedural error.
Condensate	Condensate Systems (including Condensate Demineralizers) were the source of 7 trips. Of the 7 trips, 2 were caused by an electronic component failure, 2 were caused by a procedural error, and one each for a technician or operator error, a motor failure, and a pump failure.
FWP	A main feedwater pumps (including reactor feedwater pumps) were the source of 7 trips. Of the 7 trips, 3 were caused by a pump problem, and 1 each due to an electronic component failure, a technician or operator error, a procedural error, and a motor failure.

Table 2-2 Systems and Causes

SYSTEMS AND CAUSES TABLE 2-2											
	Total	Air	Design	Electronic	Error	Hyd	Motor	Procedure	Pump	Relay	Valve
1E 4KV	2				1			1			
Condensate	7			2	1		1	2	1		
EHC	3		1	1		1					
ESFAS[1]	4			2						2	
FRV	10	8			1			1			
FWCS[2]	26		1	22	3						
FWP[3]	7			1	1		1	1	3		
FWPT[2,3]	11			4	2	2			1		2
HDLC	1	0	0	0	0	0	0	0	0	0	1
Non-1E 4KV	4				2			1		1	
Rod Control	3			3							
RPS	16		1	7	5			2		1	
Rx Recirc	1				1						
SCWS	1			1							
TPS	1				1						
Turbine	2				1	1					

SYSTEMS AND CAUSES

TABLE 2-2

	Total	Air	Design	Electronic	Error	Hyd	Motor	Procedure	Pump	Relay	Valve
Total	99	8	3	43	19	4	2	8	5	4	3

Note 1: One trip from ESFAS was attributed to a combination of two causes, an error and a relay.

Note 2: One trip from a combination of FWP and FWCS was attributed to two causes, valve (FWPT) and electronic (FWCS).

Note 3: One trip from a combination of FWP and FWPT was attributed to two causes, valve (FWPT) and electronic (FWP).

Air	A component in the air supply failed.
Design	A design failure was the direct cause of the trip.
Electronic	An electronic component failed that caused the trip.
Error	An error on the part of a technician or operator caused the trip.
Hyd	A component in the hydraulic supply failed.
Motor	A motor failed.
Procedure	An error in a procedure directly resulted in a trip.
Pump	A pump or component integral to the pump failed.
Relay	A relay failed.
Valve	A valve failed.

2.2 Frequent Operating Transients Caused Where At-Power Maintenance or Testing Was in Progress

Table 2-3 lists the systems and causes of reactor trips where maintenance or testing was in progress that directly contributed to the trip. Of the 99 system/causes of reactor trips, maintenance or testing was directly involved in 46 trips. The two leading systems involved in reactor trips were reactor protection systems (RPS) and feedwater control systems (FWCS).

RPS	Testing or maintenance was in progress for 15 of the 16 trips related to RPS. The only trip where testing or maintenance was not involved was related to a design issue.
FWCS	Testing or maintenance was in progress for 6 of the 27 trips related to FWCS. Of the 6 trips, 3 were caused by a failure in an electronic component, 2 were caused by a technician or operator error, and 1 was attributed to the system design.

Table 2-3 Systems and Causes Related to Maintenance or Testing

SYSTEMS AND CAUSES RELATED TO MAINTENANCE OR TESTING

TABLE 2-3

	Total	Air	Design	Electronic	Error	Hyd	Motor	Procedure	Pump	Relay	Valve
1E 4KV	2				1			1			
Condensate	3			1	1			1			
EHC	3		1	1		1					
ESFAS	4			2						2	
FRV	2				1			1			
FWCS	6		1	3	2						
FWP	1							1			
FWPT	0				1						
HDLC	1										1
Non-1E 4KV	3				2					1	
Rod Control	1			1							
RPS	15			7	5			2		1	
Rx Recirc	1				1						

SYSTEMS AND CAUSES RELATED TO MAINTENANCE OR TESTING

TABLE 2-3

	Total	Air	Design	Electronic	Error	Hyd	Motor	Procedure	Pump	Relay	Valve
SCWS	0										
TPS	1				1						
Turbine	2				1	1					
Total	46	0	2	15	16	2	0	6	0	4	1

Note 1: One trip from ESFAS was attributed to a combination of two causes, an error and a relay.

While the Chemical and Volume Control Systems (CVCS) did not contribute to the causes of reactor trips, this system was involved in manual actions associated with five of the trips. Three involved manual initiation of emergency boration and two involved manual control of charging and letdown. Table 2-4 lists the events and the manual actions taken.

CVCS does not contribute significantly to the number of reactor trips since the process is relatively slow moving with backup charging pumps and alternate letdown paths. Failure of a charging pump would typical result in automatic reduction in letdown flow and start of a backup charging pump. Failure of a letdown valve would either automatically start or secure a charging pump allowing time for an operator to place the alternate letdown valve in service.

RPS testing is the most common cause of spurious reactor actuations involving this system. This is because the reactor trips require coincident logic (two out of three channels or two out of four channels) to trip and it is relatively rare to have coincident random failures of channel components such as sensors and transmitters. A common situation for a spurious reactor actuations involving the RPS is where a channel is put in trip for maintenance (according to the plant's technical specifications) and there is a latent failure of a second channel undetected by the operators. A second common scenario involves human error, where two channels of the same RPS trip function are unintentionally worked on at the same time. This usually involves a component misidentification event.

As even further precaution against spurious RPS actuations, many plants have implemented a channel bypass system according to Regulatory Guide 1.47, which allows a channel to be placed in bypass rather than trip for a limited duration while the testing is in progress. In spite of all of these measures, spurious RPS actuations during maintenance and testing are still a large contributor to the number of avoidable reactor trips. Table 2-5 lists these events during the time frame considered under this study.

Even though spurious RPS trips are unacceptably high, the solution does not lend itself to the type of automation contemplated by this study – that of automating the response to a transient in lieu of manual procedure-based operator actions. There is a form of automation that would be beneficial in this category of trip and that is automation of configuration management for maintenance and testing. This would involve software control of which channels are taken out of service for maintenance and testing and related interlocks to prevent multiple channels being worked on at the same time. It would also involve real-time channel checks to detect and avoid interaction with latent failures. Again, while this might be helpful, it is out of the scope of this particular study.

Table 2-4 Trip Recovery with Manual CVCS Actuations

TRIP RECOVERY WITH MANUAL CVCS ACTUATIONS TABLE 2-4		
Unit	LER	Manual Action
Arkansas 2	3682009005	On December 08, 2009, at approximately 0837 Central Standard Time, Arkansas Nuclear One Unit 2 (ANO-2) was operating near 100 percent power when the ‘A’ Main Feedwater Pump (MFWP) [SJ] [P] was manually tripped due to high thrust bearing temperature. The subject MFWP is one of two installed MFWPs manufactured by Delaval, and utilizes an outboard Kingsbury double thrust bearing. In response to the manual trip of the MFWP, ANO-2 Operators entered the Loss of MFWP Abnormal Operating Procedure (AOP) and commenced Reactor Coolant System (RCS) [AB] boration while decreasing Main Turbine [TA] load. The Loss of MFWP AOP contained instructions that limited the Main Turbine load reduction rate (plant power reduction rate) that was necessary to recover Steam Generator (SG) [JB] water levels using the operating MFWP prior to reaching the Emergency Feedwater (EFW) [BA] automatic actuation setpoint of 22.2 percent. When water level in the ‘A’ SG decreased to approximately 27 percent, a manual Reactor trip was initiated. Actual plant feedwater flows after a loss of MFWP were less than the original engineering estimates programmed into the simulator, with no discernible increase in actual plant feedwater flows when the fourth condensate pump was started.

TRIP RECOVERY WITH MANUAL CVCS ACTUATIONS

TABLE 2-4

Unit	LER	Manual Action
Kewaunee	3052007001	Following the trip, MS-201 B1, Reheat Steam to MSR B1, [ISV] did not close, (a repeat valve failure), which resulted in additional cooldown to 536 degrees F RCS Tave. The additional cooldown resulted in letdown isolation due to low pressurizer level. Feedwater [SJ] isolated and auxiliary feedwater [BA] initiated, as designed, due to low-low level in the steam generators. No other safeguards systems actuated during the transient. Per contingency procedures, manual action was taken to isolate the reheat steam [SB], which halted the cooldown, and Tave was restored to 547 degrees F. Charging [CB] was taken to manual to restore pressurizer level and letdown flow. LD-10 was taken to manual during the restoration of letdown flow.
Kewaunee	3052007004	Following the trip, MS-201 B1, Reheat Steam to MSR B1, failed to close, (a repeat occurrence), which resulted in a reactor coolant system (RCS) cooldown to 537 degrees F. Per contingency procedures, action was taken to manually isolate the turbine moisture separator reheat steam, which halted the cooldown, and Tave was restored to 547 degrees F. The additional cooldown resulted in chemical and volume control system letdown isolation on low pressurizer level. Main feedwater isolated and auxiliary feedwater initiated, as designed, due to low-low level in the steam generators. No other safeguards systems actuated during the transient.

TRIP RECOVERY WITH MANUAL CVCS ACTUATIONS TABLE 2-4		
Unit	LER	Manual Action
Wolf Creek	4822010006	Emergency boration was initiated at 0341 CST per procedure EMG ES-02, "Reactor Trip Response," when the reactor coolant system (RCS) temperature decreased below 550 degrees Fahrenheit. This was a result of the actuation of auxiliary feedwater (AFW) and the lack of decay heat with the reactor power at 42 percent. Emergency boration was secured at 0404 CST when RCS temperature was raised to greater than 550 degrees Fahrenheit, by throttling AFW flow.
Wolf Creek	4822010012	The Control Room operators began to reduce reactor power to stay within the capacity of the Auxiliary Feed Water System by inserting control rods in manual. Recognizing that the power reduction could not be accomplished in time, the Control Room supervisor ordered the reactor be manually tripped. At 0953 CDT on October 17, 2010 the reactor automatically tripped [EIIS Code: JE] on SG 'A' Low-Low level of 23.5%, one second earlier than the manual trip.

Table 2-5 Trip Due to Spurious RPS Actuations

TRIP DUE TO SPURIOUS RPS ACTUATIONS TABLE 2-5		
Unit	LER	Direct Cause
Braidwood 1	4562010004	Maintenance placed a channel of S/G water level in trip to perform surveillance testing and the main turbine tripped causing a reactor scram. A failed logic card in the system created an unknown half trip condition.
Braidwood 2	4572009001	The Unit 2 reactor tripped due to a momentary/spurious signal spike on the 2D OTDT channel while the 2B OTDT bistable was in the tripped condition for 2B pressurizer pressure surveillance testing, making up the 2 of 4 trip logic. The investigation of this event found no issues with human performance, equipment failure, or plant activities that could have caused the signal spike. By using redundant channel coincident trip logic, the 2 of 4 logic (2 of 3 for some protective functions) design of the Reactor Trip System and Engineered Safety Features Actuation System (RTS/ESFAS) [JE] protects against unplanned or stray trip signals on a single channel, which would otherwise result in a reactor trip, while still capturing legitimate trip signals seen by multiple channels. However, this design is not fault tolerant. During maintenance activities, one channel is manually placed in the tripped position. This converts a normal 2 of 4 (or 2 of 3) logic into a more vulnerable 1 of 3 (or 1 of 2) logic. During a maintenance activity, an unplanned human error, spurious transient, or channel failure in a coincident channel initiates an inadvertent reactor trip or safeguards actuation. This design has resulted in several events within the industry including unit trips while at power. Therefore, the root cause of the Unit 2 reactor trip is determined to be the design of the RTS/ESFAS, which places a loop in a trip condition for testing, increases vulnerability during testing conditions.

TRIP DUE TO SPURIOUS RPS ACTUATIONS

TABLE 2-5

Unit	LER	Direct Cause
Brunswick 1	3252010003	The cause of the event was pulsation dampeners (i.e., with pins installed) in the reactor feed pump suction flow element sensing lines, installed in a 1977 plant modification, delayed the actuation of the low suction flow signal to the pump runback logic. This delay allowed the RPV water level to drop below the Low Level 1 setpoint, causing an automatic reactor scram on Unit 1 and activation of the RPS and the PCIS. The investigation concluded that the adverse condition was a historical problem, which has existed for such a long time that a plausible root cause could not be reasonably determined.

TRIP DUE TO SPURIOUS RPS ACTUATIONS

TABLE 2-5

Unit	LER	Direct Cause
Dresden 3	2492010001	The half-scram signal that occurred on 'B' RPS was generated from the when the 3-0590-107F relay de-energized. This relay is associated with the Nuclear Instrumentation portion of the RPS system. This relay is associated with Intermediate Range Monitor (IRM) 16, Average Power Range Monitor (APRM) 6 and Oscillation Power Range Monitor (OPRM) 6. With the Mode switch in RUN, the IRM was bypassed and could not generate a trip signal. The operating procedure that was being used to transfer the RPS bus, DOP 0500-03 Reactor Protection System Power Supply Operation, contained a prerequisite to place APRM 6 in bypass prior to commencing the bus transfer. The OPRM was the only active component in the 107F relay string. Troubleshooting indicated that OPRM 6 had no power. Further investigation revealed that the input fuse had blown on the OPRM power supply causing it to lose output power. Initial examination of the circuit board, did not reveal any failures of board components other than the blown input fuse. The board was sent out for additional testing. No defects were identified besides the blown input fuse. The fuse was replaced and the power supply was successfully turned on. All indications were within expected ranges. Following seventy-two hours of operation, no defects were identified. The power supply was sent for a detailed failure analysis. A failure analysis of the power supply indicates that the OPRM 5 VDC power supply is susceptible to electrical noise. The power supply is designed with a circuit (Crowbar Circuit) which senses voltage transients and prevents the voltage excursion from damaging voltage sensitive components downstream of the power supply output. When a voltage spike occurs, the crowbar circuit is activated, which essentially shorts the circuit to ground and blows the input fuse. This results in the power supply being turned off thus terminating the voltage transient on the downstream components. Efforts have been made to identify the source of the electromagnetic interference. However, the source has not been identified at this time. Investigations and failure analyses are continuing in order to mitigate the effects of electromagnetic interferences on the OPRM power supplies.

TRIP DUE TO SPURIOUS RPS ACTUATIONS

TABLE 2-5

Unit	LER	Direct Cause
Duane Arnold	3312009003	A root cause evaluation (RCE 1081) was completed for this event. The RCE determined that the revision to STP 3.3.3.2-09 introduced a latent error that removed the recorder from service, and interrupted the control loop. The specific root causes (RC) and contributing factors (CF) are as follows: RC1- Electrical termination changes in STP's are not reviewed with the same requirements as maintenance activities. RC2 - The site modification process does not require review of all service requirements, including how equipment is to be calibrated and tested while the unit is operating.
Duane Arnold	3312009004	A Root Cause Evaluation (RCE 1086) was completed for this event. The RCE determined that the shutdown was caused by the failure to close an instrument isolation valve for a Reactor Vessel Pressure Transmitter PT4564. The failure to close this valve resulted in creating a sensed low reactor water level on Reactor Protection System (RPS) channels A2 and B2, and thus resulted in the automatic reactor shutdown. The specific root cause and contributing factors are as follows: Root Cause: Defenses in depth were inadequate to prevent the plant transient, when the IC Technician did not completely close PT4564 V-92 during the performance of Step 7.1.62 of STP 3.3.3.2-09B.

TRIP DUE TO SPURIOUS RPS ACTUATIONS

TABLE 2-5

Unit	LER	Direct Cause
Kewaunee	3052007004	For the trip, the most probable root cause has been determined to be the combination of relay contact failures caused by: * Poor circuit design * Manufacturing defects in some installed relays * Substandard installation practices The apparent cause of MS-201 B1 sticking at 100% open was determined to have been excessive wear in the valve lower plug guide at the bushing. The valve guide had 0.143" wear due to the large clearance between the guide to the bushing and old style bushing. This wear created a ledge for the guide to latch onto the bushing while the steam flow pushed the plug/guide into the bushing.
Limerick 1	3522011002	The root cause of the event was the reactor vessel high level trip calibration and functional surveillance test revisions did not fully assess the impacts of the test equipment on the DC turbine trip circuit.
Limerick 2	3532007003	The scram was caused by an intermittent failure of a circuit card in RRCS division 1B concurrent with ongoing testing on division 1A that caused a reactor feedwater runback. The flow oscillations on HPCI and RCIC were caused by improper flow control loop setting adjustments of gain and reset.

TRIP DUE TO SPURIOUS RPS ACTUATIONS TABLE 2-5		
Unit	LER	Direct Cause
Nine Mile Pt. 2	4102010001	The direct cause of this event was venting of RHS instrumentation during planned maintenance. The root cause of this event is, Operations Management has not sufficiently monitored and reinforced standards associated with plant impact assessment during work planning.
Prairie Island 1	2822008002	The equipment root cause for the failure of the F delta Q controller is attributed to the random failure of varactor diode (CRI) located inside the controller. Although this controller was refurbished in 1985, only the capacitors were routinely replaced as part of refurbishments. Therefore, CR1 was not replaced as part of the 1985 refurbishment. The organizational cause was found to be the inadequate prioritization by the site in the creation of a preventive maintenance strategy for the analog components within the reactor protection and control system.
River Bend	4582007005	Engineering and maintenance personnel found that wiring and a terminal board in an RPS pilot scram solenoid circuit had sustained severe thermal damage. This failure had interrupted power to the Division 2 coils on the Group 2 pilot scram solenoid valves, in effect causing an undetected Division 2 half-scram signal for the Group 2 control rods. When the surveillance test inserted the half-scram signal in Division 1, the logic for the Group 2 control rods was completed, and the rods inserted as designed. A detailed examination of the components determined that the most likely cause of the thermal damage on the terminal board was a loose screw connection on one of the attached wiring lugs. No history of maintenance or testing could be found that might have required the wire to be lifted and re-terminated. It appears likely that the terminal screw had not been sufficiently tightened during

TRIP DUE TO SPURIOUS RPS ACTUATIONS

TABLE 2-5

Unit	LER	Direct Cause
		plant construction.
South Texas 1	4982010003	Root Cause No. 1 (Organizational) Procedure place keeping standards for the site were less than adequate. Root Cause No. 2 (Organizational) Supervisory Oversight of surveillance test procedure OPSP03-SP-0006R became ineffective when the SRO stepped outside of his oversight role and became involved in the process.
St. Lucie 2	3892011002	A root cause determined the event was "human error vulnerability" resulting from a previous 1998 procedure change in the test methodology which required depressing the matrix relay hold pushbutton during the performance of the entire test, placing the circuit in a ready-to-actuate state.
Turkey Point 4	2512010004	The event was evaluated to determine the root cause and contributing causal factors. There were two root causes identified for the event: 1. Deficiencies in the work order package and guiding procedure failed to establish and/or verify the plant conditions required to successfully complete the evolution and relied on Operations staffing to provide the validation that the evolution could be performed. 2. The station failed to meet the standard of excellence expected for communication, accountability, ownership, formality, and rigor resulting in no one group having the full picture required to successfully complete the evolution.

TRIP DUE TO SPURIOUS RPS ACTUATIONS

TABLE 2-5

Unit	LER	Direct Cause
Turkey Point 4	2512010006	The root cause of the event is excessive pin separation in ELCO connectors which is causing component failures due to inadequate installation instructions and inspection criteria. A contributing cause is that the modification implementation instruction contains no special installation instruction with respect to pin separation in ELCO connectors.

3. Advantages of Automation of Manual Actions

In the early days of this generation of plants, a manual response was probably necessitated by the high cost of automation due to hard-wired, analog systems, which couldn't distinguish between a component failure and a sensor failure. The point of this project is to identify those situations where modern automation technology can provide a much better response to these situations.

Executing procedural actions is a slow deliberate process. Response to off-normal conditions typically begins with the response to a control room alarm. Depending on the type of alarm, it may take some time to diagnose the condition which may include dispatching an operator to conduct a local inspection of the alarming condition. Once the condition has been diagnosed the appropriate procedure needs to be referenced. All of the procedure prerequisites must be confirmed as being met. Then the procedurally described actions may be completed.

Some typical actions that may be taken in response to an off normal condition include things like swapping the controlling channel, verifying by alternate indication that a sensor has failed, putting standby equipment in service, taking manual control of pumps and valves to control flow rates, swapping to alternate sources of power, water, instrument air, etc.

Conducting manual actions in response to an off-normal condition is an error likely process. In the course of conducting the procedure, there may be steps that are missed or perhaps steps that are executed out of sequence. The procedure itself may contain latent errors that lead to adverse results. Reverting to manual control may present the operator a situation that is not often encountered. This could lead to inadequate control of the process. For example, feedwater control is not an intuitive process. A number of factors such as reactor coolant system temperature, power level, steaming rate and feedwater temperature play a role making manual control difficult. Implementing an automated process to replace manual conduct of procedural actions could improve the time efficiency and reduce errors related to accomplishing the task.

The reactor trips that were included in the review can be divided into two categories. One category is where the reactor trips with essentially no prior warning to the control room operators. This is frequently the case where a test or maintenance activity initiates the trip. A second category is where the control room operator is alerted to an off-normal condition, typically by a control room annunciator, and may attempt to take compensatory actions to avoid the reactor trip. A preliminary assessment of the LERs identified 70 of 95 trips where there was at least a small amount of time for operator response.

Many equipment failures are not specifically addressed by procedures or the technical specifications. Table 3-1 shows the manual actions identified in the evaluated LERs that were necessary to accommodate an equipment failure. Two of the events required manual isolation of the moisture separator reheater steam supply to limit the cooldown of the primary system. Two events required manual operation of the HPCI and/or the RCIC systems due to observed flow oscillations. One event caused a momentary loss of some non-1E 120 volt loads as a result of transfer of power between transformers. The momentary loss of power caused 4 steam dump valves to not open as quickly as needed. During another event, a moisture separator reheater drain valve failed to close and had to be closed manually (its backup did close). One event involved a turbine driven auxiliary feedwater pump to trip shortly after a successful automatic start. And finally, during one event, it was necessary to manually close the main steam isolation valves to control the primary system cooldown.

Table 3-1 Trip Recovery with Equipment Failures

TRIP RECOVERY WITH EQUIPMENT FAILURES Table 3-1		
Unit	Docket/LER	Manual Action
Kewaunee	3052007001	Following the trip, MS-201 B1, Reheat Steam to MSR B1, [ISV] did not close, (a repeat valve failure), which resulted in additional cooldown to 536 degrees F RCS Tave. The additional cooldown resulted in letdown isolation due to low pressurizer level. Feedwater [SJ] isolated and auxiliary feedwater [BA] initiated, as designed, due to low-low level in the steam generators. No other safeguards systems actuated during the transient. Per contingency procedures, manual action was taken to isolate the reheat steam [SB], which halted the cooldown, and Tave was restored to 547 degrees F. Charging [CB] was taken to manual to restore pressurizer level and letdown flow. LD-10 was taken to manual during the restoration of letdown flow.
Kewaunee	3052007004	Following the trip, MS-201 B1, Reheat Steam to MSR B1, failed to close, (a repeat occurrence), which resulted in a reactor coolant system (RCS) cooldown to 537 degrees F. Per contingency procedures, action was taken to manually isolate the turbine moisture separator reheat steam, which halted the cooldown, and Tave was restored to 547 degrees F. The additional cooldown resulted in chemical and volume control system letdown isolation on low pressurizer level. Main feedwater isolated and auxiliary feedwater initiated, as designed, due to low-low level in the steam generators. No other safeguards systems actuated during the transient.
Limerick 2	3532007003	HPCI and RCIC were placed in manual mode while injecting to the reactor due to speed and flow oscillations observed by the Reactor Operator.
Millstone 2	3362008005	The testing of the #1 CIV had been completed satisfactorily and testing of the.#3 CIV had just been completed when the 2A feedwater heater [HX] level began oscillating. The oscillations became divergent, requiring the operators to take manual control of the 2A feedwater heater level. Subsequently, high level alarms on the 3A and 3B feedwater heaters were received. Following the trip, during the automatic transfer of the in-house electrical buses from the Normal Station Service Transformer (NSST)

TRIP RECOVERY WITH EQUIPMENT FAILURES Table 3-1		
Unit	Docket/LER	Manual Action
		[XFMR] to the Reserve Station Service Transformer (RSST) [EA, XFMR], there was a momentary loss of the non-safety grade, 120 volt, power supplies (VR-1 1 and VR-21) [JX] to the annunciators and control boards when they transferred to their alternate power supplies. The steam generator #2 atmospheric dump valve [RV] and the steam generator #1 safety valve [RV] opened. Additionally, the 'A' steam dump valve to the condenser modulated open, however the 'B', 'C' and 'D' dump valves did not quick open due to a momentary loss of power from VR-1 1. All the steam dump valves were opened and steaming was re-established to the condenser. The unit was maintained in a stable condition, i.e., hot-standby (Mode 3).
Perry	4402007004	The MFP minimum flow valve could not be opened due to loss of the DFWCS power supplies. The operators also attempted to perform a quick start of RFPT A, but were unable to control the turbine on its potentiometer. The operators started the RCIC system manually at approximately 0850 hours. Subsequent to RCIC pump start, the system experienced flow variations from 50 to 100 gallons per minute and tripped ton low pump suction pressure at 0908 hours. At 0915 hours, the operators re-started the RCIC system with the flow controller in manual control. Discharge flow was directed to the RPV and CST simultaneously. The RCIC system was then used for RPV level and pressure control. At 1310 hours, RPV pressure had decreased to allow the operators to transition RPV level control from RCIC to the feedwater booster pumps. At 1630 hours, the operators placed shutdown cooling in operation.
Point Beach 1	2662007004	One moisture separator reheater drain valve, 1 FD-02603, failed to automatically shut and was manually, shut. The function of the drain valve is to prevent steam within the reheat system from reaching the turbine and causing an overspeed condition. The automatic failure did not impact the response to the reactor trip because a redundant valve, 1 FD-02604, located in series with the affected valve, successfully shut, thus providing the same function.

TRIP RECOVERY WITH EQUIPMENT FAILURES Table 3-1		
Unit	Docket/LER	Manual Action
Prairie Island 1	2822008002	All automatic actions for a reactor trip occurred as required with the following exceptions: Subsequent to the trip, the Unit 1 turbine-driven auxiliary feedwater pump (1 1 TDAFWP) auto started as designed, but tripped 42 seconds later on low discharge pressure. And a Unit 1 Turbine 2 Reheat Stop Valve indicated intermediate vice closed. However, physical inspection verified that this valve was indeed closed and that the intermediate indication was caused due to a failed switch rod (linkage) that actuates a proximity switch to indicate valve position. Operator response and recovery actions for the reactor trip were completed as expected.
Wolf Creek	4822010006	Emergency boration was initiated at 0341 CST per procedure EMG ES-02, "Reactor Trip Response," when the reactor coolant system (RCS) temperature decreased below 550 degrees Fahrenheit. This was a result of the actuation of auxiliary feedwater (AFW) and the lack of decay heat with the reactor power at 42 percent. Emergency boration was secured at 0404 CST when RCS temperature was raised to greater than 550 degrees Fahrenheit, by throttling AFW flow.
Wolf Creek	4822010012	The Control Room operators began to reduce reactor power to stay within the capacity of the Auxiliary Feed Water System by inserting control rods in manual. Recognizing that the power reduction could not be accomplished in time, the Control Room supervisor ordered the reactor be manually tripped. At 0953 CDT on October 17, 2010 the reactor automatically tripped [EIIS Code: JE] on SG 'A' Low-Low level of 23.5%, one second earlier than the manual trip. Emergency Boration [EIIS Code: CB] was initiated at 1001 CDT. The Control Room operators took additional action to terminate the cooldown by isolating major steam loads and reducing AFW flow. At 1048 CDT, operators took additional action to eliminate the cooldown and closed the Main Steam Isolation Valves [EIIS Code: SB-ISV]. With all steam loads isolated, RCS temperature recovered and the operating crew stabilized the plant at hot standby.

4. How Automating Response/Recovery Would Improve Success

Automating the response of a unit to off normal conditions could potentially improve plant reliability by avoiding some reactor trips. Those trips where there was no advance indication to the control room operator are not candidates for a recovery response since there is no time to conduct any mitigating actions. However, over 70% of the evaluated LERs provided at least a small amount of time for mitigating the event.

In addition to having some time to execute mitigating actions, the means to implementing the actions must also be available. For example, if there is a failure in the air supply or control equipment to a feed regulating valve, there is no alternative system available to take mitigating actions in the required time frame. If the time and means are available automated response to some off normal conditions could be successful in avoiding reactor trips.

Automation of the diagnosis of plant conditions could improve the accuracy of the diagnosis of adverse conditions and improve the timeliness of response to off normal conditions.

5. Candidates for Automation to Improve Success

There are a number of opportunities to reduce the number of reactor trips. There are a range of actions that may be taken to automate the response to an off normal condition. With current technology, the health of sensors can be diagnosed and switching to an alternate sensor can be built into the design. Likewise, alternate electrical power or air supplies can be monitored and automatic transfer can be designed in the event of an upset condition with the primary.

Focusing on the primary contributors to trips provides the best opportunity for success. From Table A-1, of the 99 identified causes of reactor trips, 56 were related to the feedwater system. Additionally, 7 were related to the condensate system where the trip occurred due to the resulting impact on the feedwater system. Of the 96 events, manual operator actions were identified in the LERs in 47 of the events. Table 5-1 lists the manual operator actions that are identified in the evaluated LERs either prior to the reactor trip and/or following the reactor trip.

Table 5-1 Manual Operator Actions

MANUAL OPERATOR ACTIONS Table 5-1	
Operator Action	Events
Manually controlled AFW	2
Manually operated charging and letdown	2
Initiated emergency boration	2
Tripped main turbine	1
Manually secured condensate pump	1
Manually initiated safety injection	1
Manually operated feedwater bypass valve	2
Manually operated main feedwater valve	16
Manually tripped main feedwater pump	2
Manually operated main feedwater pump turbine	5
Manually controlled feedwater heater level	1
Manually operated steam bypass system	1
Manually operate high pressure coolant injection	1
Manually operated MSIVs	1
Manually isolated moisture separator reheater	1
Manually operated nuclear instrumentation	1
LER specifically stated no operator action	2
LER did not specifically identify an operator action	49
Manually operated reactor core isolation cooling	6
Manually operated reactor recirculation system	3
Manually operated electromatic relief valves	1
Manually started stator cooling water pump	1

Some candidate opportunities to reduce the frequency on reactor trips are redundant feedwater controls, automated response to a feedwater or condensate pump trip reducing power vice a reactor trip, and elimination of air operators for the feedwater control valves or providing redundant air supplies.

Redundant Feedwater Control

The feedwater control system was identified as a cause of 27 reactor trips over the evaluation period. Twenty-three of those trips were due to a problem related to the electronic control system. A redundant electronic control system for each feedwater control valve offers a means for avoiding the majority (if not all) of the reactor trips from this cause. Some nuclear units have implemented redundant feedwater control.

Improved Feedwater Regulating Valve Operators

Most feedwater control valves utilize an air operator to position the valve. This requires an air supply, a pressure regulator, a current to pressure converter, and the air operator. These air components caused 8 trips over the evaluation period. A potential improvement is to replace the air components with an electric valve positioner. An electric positioner equipped with redundant power sources and electronic controls has the potential to significantly reduce trips caused by feedwater regulating valve air operator issues. Another possibility is to provide redundant air supply components with an automatic switchover when signal and air pressure do not match.

Improved Feedwater Pump Turbine Control

Similar to the opportunities to improve feedwater valve control, implementation of redundant electronic feedwater pump turbine control and/or electric governor valve positioning has the potential for reducing nuclear unit trips. From Table A-1, 4 reactor trips were caused by electronic feedwater pump turbine control and two were caused by hydraulic components in the feedwater pump turbine speed control system.

Automated Response to Feedwater Pump Trip

An alternative (or compliment) to changes to the feedwater turbine controls is to automate the response of the feedwater system to a feedwater pump trip. Most nuclear units operate with control rods fully withdrawn. A consequence of this strategy is that reactor power reduction is slow when control rods are inserted until they reach a significant amount of rod insertion. The significant obstacles to achieving the ability to reliable operate through a feedwater pump trip are to maintain steam generator level control and to control primary system temperature while bringing reactor power and the steam demand into balance. An integrated feedwater control system that can automatically lower power (turbine runback for PWRs, recirculation pump runback for BWRs) could prevent the a number of scrams from this group.

Reduction of Spurious Reactor Protection System Trips

After feedwater events, trips of the reactor protection system account for the most reactor trips over the evaluation period. Since reactor protection systems are not control systems, automation is not a prime option to reduce trips. The overwhelming majority of the RPS trips occurred during maintenance or testing. There are several potential changes that would likely be effective in reducing the number of spurious RPS trips. Some plants are conducting analyses necessary to extend the surveillance interval for the reactor protection system periodic testing. Utilizing probabilistic risk assessment tools, it may be possible to significantly increase the required surveillance test intervals for reactor protection systems.

Of the 16 trips associated with reactor protection systems, 5 occurred due to a pre-existing unknown half trip condition. It may be possible to install an automatic indication of a half trip condition so that the failed component could be repaired prior to performing a trip test on an alternate channel.

6. Task 2: Identify Issues and Approaches Associated with Runback to House Load on Loss-of-Load

This task explores the issues and possible approaches for improving the capability of the current operating nuclear fleet to successfully run back to house load following a loss-of-load or load rejection event. A successful runback avoids tripping the reactor subsequent down-time of approximately two days before the unit can be back in service and providing power to the grid. It is desired for the unit to be reconnected to the grid rapidly following the runback to prevent minor grid disturbances from expanding into major grid disturbances like the grid collapse of 2003.

The current operating nuclear fleet has varying capabilities to successfully run back to house loads following load rejection events. Some designs are already fully capable, and other designs would require significant designs changes to reach an equivalent capability. The design features that enhance or limit that capability are identified, and the opportunities to modify the plant designs to achieve the desired load rejection capability are discussed. A primary issue is to determine any impact on nuclear safety, which involves performing analyses to evaluate the impact of any proposed design changes on the regulatory requirements established by the NRC. The cost of designing and installing the design changes, performing the required analyses, and obtaining NRC approval, would then need to be evaluated against the benefit of the increased capability to handle a load rejection and avoid contributing to major grid disturbances.

7. Loss-of-Load Transients

7.1 Types of Loss-of-Load Scenarios

The scenarios categorized as loss-of-load transients include all those initiating events, along with consequential responses of plant components that result in the separation of the electrical output of the main electrical generator from the offsite grid. This includes loss of the offsite electrical grid itself, commonly referred to as a loss-of-offsite-power (LOOP), as well as failures of components in the plant switchyard (transformers, busses, switchgear, etc), and failures resulting in opening of the main generator breakers. These loss-of-load transients may occur at full power or at partial power, and with different switchyard configurations. Because the most probable initial condition for these events is full power with the normal plant configuration, that scenario is the main focus of this study.

7.2 Advantages of Successful Runback

The capability for a plant to successfully run back to house load following a load rejection has many advantages:

- Nuclear safety will be enhanced
  - Avoids potential consequences that begin with a reactor trip initiating event
  - The probability risk assessment (PRA) will not be adversely affected
  - Fewer challenges to plant safety systems
- Loss of generation will be minimized
  - The time lost to recover from a reactor trip will be avoided
  - Reduced regulatory requirements and interactions
  - No event investigation and review
- Grid stability will be enhanced with less time required to reconnect a unit to the grid that has run back to house loads
- Capacity factors are increased if generation remains on-line

7.3 PWR Design Basis Loss-of-Load Safety Analysis

The PWR loss-of-load event is an anticipated operational occurrence (AOO) as defined in Appendix A to Part 50, "General Design Criteria for Nuclear Power Plants". The NRC guidance for performing the safety analysis for the loss-of-load event is provided in the Standard Review Plan (NUREG-0800), Section 15.2.1, "Loss of External Load". For AOOs the following acceptance criteria are specified:

- The specified acceptable fuel design limits (SAFDLs) are not exceeded
  - The centerline fuel melting (CFM) temperature is not exceeded
  - The minimum departure-from-nucleate boiling ratio (DNBR) is not exceeded
  - The cladding strain limit is not exceeded
- The peak primary system pressure does not exceed 110% of the design limit
- The peak secondary system pressure does not exceed 110% of the design limit

The safety analysis is performed by simulating the plant response to all loss-of-load scenarios with a system thermal-hydraulic analysis code, and is presented in UFSAR Chapter 15. In these simulations conservative assumptions are used for the plant initial conditions and the response of plant systems and components so that an overall conservative result is assured. No credit for non-safety grade plant control systems is allowed, so the safety analysis is not typical of the actual expected plant response to a loss-of-load event. The main purpose of the safety analysis is to demonstrate that the fuel and pressure boundaries are protected by the safety-grade equipment, which typically consists of the following:

- The Reactor Protection System (prevents fuel failure by dropping all control rods / prevents over pressurization by limiting the heat source)
- The Reactor Power Cutback System (prevents fuel failure by dropping select control rods / prevents over pressurization by limiting the heat source – only installed in some CE plants)
- The pressurizer code safety valves (prevents primary system over pressurization)
- The secondary code safety valves (prevents secondary system over pressurization)
- The Auxiliary Feedwater System (prevents fuel failure and primary system over pressurization by providing decay heat removal)

For the loss-of-load event the Reactor Protection System trip functions that protect the fuel and the pressure boundaries can include the following depending on the specific plant design:

- A reactor trip on loss-of-load or due to a turbine trip caused by the loss-of-load. This type of trip function is typically enabled above a reactor power level for which the plant design cannot survive a loss-of-load without some other reactor trip occurring subsequently. For example, a plant with a steam dump capacity of 50% cannot handle a loss-of-load greater than 50% (or above an initial power level of 50%), and so an immediate reactor trip will occur on this trip function for those events.
- A reactor trip on high primary system pressure (i.e. pressurizer or hot leg pressure). This trip function is necessary to protect the primary and secondary pressure boundaries.
- A reactor trip on over-temperature ΔT or over-power ΔT (for Westinghouse PWRs). These trip functions protect the fuel from centerline fuel melt (CFM) and departure-from-nucleate-boiling (DNB), which are the two main safety concerns for protecting the fuel cladding during AOOs. Should CFM occur the cladding will potentially fail from excessive thermal expansion of the fuel pellet, which overstresses the cladding causing it to crack open. Should DNB occur the cladding temperature will potentially fail from overheating, due to the heat transfer from the cladding surface degrading as it transitions from efficient nucleate boiling to inefficient film boiling. DNB can occur from an adverse combination of heat flux, temperature, flow, and pressure.
- Other reactor trip functions designed to protect the fuel from failure due to exceeding the CFM and the DNBR limits (CE design plants with and without the Core Protection Calculator (CPC) digital trip functions).

7.4 BWR Design Basis Loss-of-Load Safety Analysis

The NRC guidance for performing the safety analysis for the loss-of-load event is provided in the Standard Review Plan (NUREG-0800), Section 15.2.1, "Loss of External Load", and 15.2.6 "Loss of Nonemergency AC Power to the Station Auxiliaries". For AOOs the following acceptance criteria are specified:

- The specified acceptable fuel design limits are not exceeded
  - The centerline fuel melting (CFM) temperature is not exceeded
  - The critical power ratio (CPR) is not exceeded
  - The cladding strain limit is not exceeded
- The peak primary system pressure does not exceed 110% of the design limit

As with the PWRs, the safety analysis is performed by simulating the plant response to all loss-of-load scenarios with a system thermal-hydraulic analysis code, and is presented in UFSAR Chapter 15. Conservative assumptions regarding initial conditions, trip set points and delays and single failures and no credit is taken for non-safety grade plant control systems. These analyses demonstrate that the transients do not violate the NUREG-800 acceptance criteria.

NUREG-0800, Section 15.2.1 describes a loss-of-load event caused by an electrical disturbance that can cause a significant drop in load demand. For this transient, AC power remains available to operate plant equipment and components. Emergency diesel power is no not needed.

NUREG-0800, Section 15.2.6 describes a complete loss of load due to the loss of AC power. The loss of AC power triggers a reactor trip.

8. Pressurized Water Reactors

8.1 Desired PWR Plant Response

The desired plant response following a loss-of-load is for the unit to initiate a plant runback to house electrical loads with the turbine on-line (in the range of 10-15% power), while avoiding exceeding any of the reactor or turbine trip set points. A plant runback consists of a reactor runback – an automatic insertion of control rods to reduce the thermal energy source, and a turbine runback – an automatic closure of the main turbine control valves to reduce the steam flow to the turbine so that the house electrical load is attained. Steam relief to the main condenser and to the atmosphere is used to balance the energy transfer. Pressurizer spray and PORV actuation limits the primary pressure and improves the capability to avoid the high pressure reactor trip setpoint. In addition, both the primary and the secondary systems temporarily function as heat sinks until the energy transfer can be balanced. The imbalance of the energy transfer is what causes the reactor and turbine trip set points to be approached. Many plant systems and components must respond as designed in a coordinated manner for the plant to successfully run back and handle the loss-of-load events. The load rejection capability of the operating fleet varies due to differing designs and margins, with all designs capable of withstanding partial load rejections, and some designs including full load rejection capability. The safety analysis of the plant response to a load rejection must demonstrate that the primary and secondary peak pressure limits are not exceeded, and that the DNBR limit is not exceeded. Load rejection capability has not been a focus of the industry. Reactor power uprates, which are a focus of the industry, reduce the load-rejection capability.

8.2 Overview of Loss-of-Load Transient for Various Plant Designs

The typical response of a pressurized water reactor to a loss-of-load initiating event would consist of the following sequence of events. (Note that for some designs and above certain power levels a loss-of-load may result in an immediate reactor trip and the following sequence of events is not applicable):

- The load rejection event is detected by various sensors
- The load rejection mitigation circuitry is actuated, and plant alarms actuate
- The main generator output is transferred to provide house loads
- The loss of electrical energy transfer from the main generator causes the turbine speed to increase (mechanical energy stored in turbine/generator)
- The turbine control (governor) valves close (turbine runback) to maintain turbine speed at setpoint (e.g. 1800 rpm)
- The steam generator pressure increases due to the turbine control valve closure (thermal energy stored in the secondary system)
- The control rods insert (reactor runback) to reduce reactor power (reduce thermal energy input to primary system)
- The primary system temperature and pressure increases (thermal energy stored in primary system). Pressurizer spray and PORVs actuate to mitigate the pressure increase.
- The secondary steam relief systems actuate due to increasing main steam pressure and/or increasing primary temperature (reduce thermal energy stored in secondary system). These systems include
  - Steam dump to the main condenser (turbine bypass)
  - Steam dump to atmosphere

Main feedwater pump speed and control valves are adjusted to match demand

- Control systems (main turbine control, feedwater control, steam dump control, reactor control, and primary pressure control) continue to respond by balancing heat sources and heat sinks to stabilize the unit at house electrical load.
- Some operator actions may occur to optimize control of the plant and to respond to off-normal situations
  - The operator can respond to identified system and component malfunctions by taking manual control
  - Training experience on the control room simulator and associated procedure revisions for loss-of-load events can include specific manual actions to enhance unit continuity and stability (e.g. manual control of main feedwater system and steam dump system; manual control of main turbine; manual insertion of control rods; manual actuation of pressurizer PORVs)

The typical response of a pressurized water reactor as described above is discussed further based on the major design differences within the fleet for the following six plant design categories:

<u>Westinghouse 4-Loop Design</u>

The Westinghouse 4-loop plant was designed with the intent of providing a 100% load rejection capability provided that sufficient secondary steam relief capacity exists. For some plants this capability does not exist and a loss-of-load above a specific power level will result in an immediate turbine and reactor trip. The initial power level for which a high pressure reactor trip would occur is the basis for the turbine and reactor trip on loss-of-load. The design includes a secondary steam relief capacity that combines steam dump to the main condenser, steam dump to atmosphere for the express purpose of enhancing load rejection capability, and steam dump to the atmosphere through the steam line PORVs. The main steam code safety relief valves are not expected to actuate for a load rejection event. The steam dump valves are actuated in a staggered manner based on a primary temperature deviation signal. The control rods are inserted with a variable insertion speed based on a temperature deviation signal. The pressurizer PORVs (two or three) are actuated based on a pressure setpoint or a temperature deviation signal, and provide a significant pressure relief capacity to prevent reaching the high pressure reactor trip setpoint. The over-temperature ΔT and over-power ΔT reactor trip functions are expected to be the trip functions that limit the operating continuity of the plant following a load rejection event. In addition, there are reactor trip set points on low voltage and low frequency on the 6900V supplies to the reactor coolant pump motors. If a loss of load causes a decrease in voltage or frequency below the trip set points the reactor will trip. The objective is for the runback to successfully stabilize the plant at house electrical loads with the turbine on-line (10-15% power).

Westinghouse 3-Loop Design

The Westinghouse 3-loop plant was designed with the intent of providing a 100% load rejection capability provided that sufficient secondary steam relief capacity exists. For some plants this capability does not exist and a loss-of-load above a specific power level will result in an immediate turbine and reactor trip. In addition, the time-in-cycle has a strong influence on the capability to handle a load rejection due to the negative reactivity resulting from the moderator temperature coefficient (MTC). Later in cycle the MTC is more negative and the load rejection capability is enhanced. The negative MTC assists with the reactor runback by adding negative reactivity due to the coolant temperature in the reactor increasing following the load rejection. The turbine runback rate is ~10%/min. The design includes a secondary steam relief capacity that combines steam dump to the main condenser (~50%), steam dump to atmosphere for the express purpose of enhancing load rejection capability (~20%), and steam dump to the atmosphere through the steam line PORVs (~20%). The main steam code safety relief valves are not expected to actuate for a load rejection event. The steam dump valves are actuated in a staggered manner based on a primary temperature deviation signal. The control rods are inserted with a variable insertion speed based on a temperature deviation signal. The reactor runback rate is ~5%/min. The pressurizer PORVs (two or three) are actuated based on a pressure setpoint or a temperature deviation signal, and provide a significant pressure relief capacity to prevent reaching the high pressure reactor trip setpoint. The over-temperature ΔT and over-power ΔT reactor trip functions are expected to be the trip functions that limit operating continuity following a load rejection event. The design process for these two set points allows the margin to be allocated on a plant-specific basis, and so either trip may be the limiting trip. In addition, there are reactor trip set points on low voltage and low frequency on the 6900V supplies to the reactor coolant pump motors. The low frequency trip function protects the fuel against a reduction in core flow (and the potential for fuel failure caused by DNB) due to the reactor coolant pump motors slowing down as frequency decreases. If a loss of load causes a decrease in voltage or frequency below the trip set points the reactor will trip. The objective is for the runback to successfully stabilize the plant at house electrical loads with the turbine on-line (10-15% power).

Westinghouse 2-Loop Design

The Westinghouse 2-loop plant is designed with the intent of providing a 50% load rejection capability. An automatic reactor trip will result for load rejections larger than 50%. The high pressure, over-temperature ΔT, and over-power ΔT reactor trip functions are the trip functions that limit the operating continuity following a load rejection event. In addition, there are reactor trip set points on low voltage and low frequency on the 6900V supplies to the reactor coolant pump motors. If a loss of load causes a decrease in voltage or frequency below the trip set points the reactor will trip.

Combustion Engineering Design With RPCS

The Combustion Engineering plant design has full load rejection capability using the Reactor Power Cutback System (RPCS). The RPCS senses a load rejection and drops one or more pre-selected control rod groups into the reactor (i.e. partial reactor trip) to effect a step reduction in reactor power level. The turbine initiates a runback and excess steam is dumped to the main condenser and to the atmosphere, with a total steam dump capacity of approximately 80% of full steam flow. The secondary safety valves do not open for a load rejection when the steam dump system functions correctly. The objective of the design following a load rejection is to stabilize the plant at 60% reactor power with steam dump to the condenser. The reactor is protected by the high pressure trip and the DNBR trip, but these should not actuate. There is also a reactor trip on low reactor coolant pump speed with a setpoint of 95% of nominal speed. Note that this design has pressurizer spray but does not include PORVs.

Combustion Engineering Design Without RPCS

The Combustion Engineering Design without RPCS will experience an automatic reactor trip if the load rejection exceeds the steam dump capacity. Therefore, this design cannot survive a full load rejection as the steam dump capacity is typically 50%. The other design features are similar to the with RPCS design.

Babcock & Wilcox Design

The Babcock & Wilcox (B&W) plant was originally designed with significant load rejection capability due to the fast-responding Integrated Control System (ICS). A plant runback at 20%/min is initiated following a load rejection. The secondary steam dump to condenser capacity is nominally 25% of full main steam flow, with additional secondary ADVs/PORVs installed at some plants. Following the accident at TMI-2 the NRC mandated a design change that has essentially defeated load rejection capability. The high pressure reactor trip setpoint was lowered, and the pressurizer PORV actuation setpoint was raised, such that a load rejection above 40-55% power will now cause a high pressure reactor trip, and the PORV open setpoint will not be challenged. There is also a reactor trip on low power to the reactor coolant pump motors.

8.3 Limitations in Current Designs

Westinghouse 4-Loop Design

The Westinghouse 4-loop design has a reactor trip based on turbine trip above a certain power level, and a turbine trip will occur on a load rejection that exceeds its steam dump capacity. Therefore, the steam dump capacity is limiting for 4-loop plants. Also, the reactor runback rate is limiting.

Westinghouse 3-Loop Design

The Westinghouse 3-loop design is limited by the reactor runback rate during the earlier part of the fuel cycle when the MTC is not sufficiently negative.

Westinghouse 2-Loop Design

The Westinghouse 2-loop design is limited by the steam dump capacity.

Combustion Engineering Design With RPCS

The Combustion Engineering design with RPCS does not have any limitations and has the capability to survive large load rejections without a reactor trip. However, it is necessary to manually down power the unit to allow the main turbine to be re-synchronized properly before reconnecting to the grid.

Combustion Engineering Design Without RPCS

The Combustion Engineering design without RPCS is limited by the steam dump capacity, in addition to the absence of the RPCS.

Babcock & Wilcox Design

The B&W plants were required by NRC to lower the high pressure reactor trip setpoint, and raise the pressurizer PORV setpoint following the TMI-2 accident. This design change has restricted the loss-of-load capability to a range of 40-55% initial power, or a partial load rejection of approximately 50%. The NRC would need to agree to delete this requirement for any improvement in load rejection capability for the B&W design. Obtaining NRC agreement is expected to be difficult due to the impact of increasing challenges to the PORV and the associated impact on the PRA.

8.4 Discussion of Probability of Success in Runback to House Loads

For the current plant designs only the large CE plants with the power cutback system, and the Westinghouse plants with large steam dump capacity, have a capability to handle a large load rejection. Other designs can only handle partial load rejections.

Complications of Concurrent Equipment Failures

The three control functions that must perform correctly for a plant to handle a load rejection are the rod control system (or the RPCS for those CE design that have installed it), the steam dump system, and the pressurizer pressure control systems. As stated above, only certain plants can survive a full load rejection. Concurrent equipment failures in any of these three control functions would likely result reactor trip following a large load rejection.

Possible Control Changes That Would Improve Success

The RPCS (partial reactor trip) design employed in the CE design would significantly improve the capability to survive load rejections in the other designs, provided that sufficient steam dump capacity exists. Without the power cutback feature a design change to increase the reactivity insertion rate (faster rod insertion speed and/or higher differential control rod worth) would improve the plant response to load rejections. A faster rod insertion speed may or may not be possible with the existing control rod drive mechanisms. A higher differential control rod worth may be possible by grouping the control rods differently so that more rods or higher worth rods are in the control bank that is inserted when a load rejection is detected.

Optimization of the steam dump system may also be possible, such as designing an anticipatory strategy focused on load rejection capacity rather than simple secondary pressure control or simple primary temperature control.

Optimization of the feedwater control system may be possible, such that feedwater pump speed and control valve position, and the resulting steam generator inventory, would be better matched to the reactor heat generation during the reactor runback. This would assist in preventing a reactor trip on high pressure, and would also prevent a reactor trip on the trip functions that protect the fuel from DNB.

For the Westinghouse plants the turbine/reactor trip setpoint on loss of load could be optimized based on the time-in-cycle (by incorporating the MTC variation into the design), and with consideration for the end-of-cycle T-ave reduction (or reduced T-ave operation). Other optimizations of the over-power ΔT and over-temperature ΔT trip set points may be possible for Westinghouse plants. These trip functions set points can be set in various combinations to provide margin for various purposes, such as to avoid turbine runback on high ΔT caused by hot leg temperature spiking. The potential benefit of a certain combination of ΔT set points to enhance load rejection capacity can be studied. However, any change will cause a loss of margin that may affect safety analyses for other Chapter 15 transients. Reanalysis of the Chapter 15 events that credit the ΔT set points will be a significant engineering and licensing effort, with associated cost.

Also, refinements in the analysis inputs related to control systems may also provide an opportunity to justify optimizing the set points to enable handling large load rejections. As an example, analysis inputs may allow for a wider band of primary temperature control than is actually used at the plant, and narrowing the control band would have a beneficial impact on load rejection capacity. Other examples would be reducing overly conservative assumptions for steam generator tube plugging or primary coolant flow.

It is noted that the above control system changes that are non-safety-grade cannot be credited in the UFSAR Chapter 15 safety analyses of the loss-of-load event.

Possible Mechanical System Changes That Would Improve Success

Additional steam dump capacity would improve the capability to handle load rejections for all designs (except for those with 100% capacity). Additional pressurizer spray or PORV capacity would also be an improvement for designs that are limited by the high reactor pressure trip. Refinements in the analysis inputs related to mechanical systems may also provide an opportunity to justify optimizing the set points to enable allow large load rejections. These refinements would include actual plant performance parameters for SSCs such as steam dump valve capacity and valve stroke times.

It is noted that the above mechanical system changes that are non-safety-grade cannot be credited in the UFSAR Chapter 15 safety analyses of the loss-of-load event.

The Table 8-1 summarizes the key design considerations for PWRs and also includes the number of units in each of the six PWR plant categories:

Table 8-1 Candidate Design Changes for PWR Plant Categories

Candidate Design Changes for PWR Plant Categories Table 8-1			
Plant Category	**Number of Units in U.S.**	**Current Design Limitations**	**Candidate Design Changes**
Westinghouse 4-Loop	29	Steam dump capacity, small margin to reactor trip	RPCS OR optimized controls and increased steam dump capacity
Westinghouse 3-Loop	13	Steam dump capacity, small margin to reactor trip	RPCS OR optimized controls and increased steam dump capacity
Westinghouse 2-Loop	6	Steam dump capacity, small margin to reactor trip	RPCS OR optimized controls and increased steam dump capacity
CE with RPCS	4	None	N/A
CE without RPCS	10	Steam dump capacity	RPCS
Babcock & Wilcox	7	Post-TMI-2 imposed design changes	RPCS AND reverse imposed design changes

9. Boiling Water Reactors

9.1 Desired BWR Plant Response

The older BWR design plant response to a loss-of-load transient results in a fast reactor vessel pressurization. The steam line safety valves prevent the vessel pressure from exceeding 110% of the design pressure.

The reactor power at nominal conditions is controlled by the amount of core voiding (regulated by recirculation pump flow control). When the RPV pressure increases, it collapses a substantial amount of the voids in the core which increases neutron moderation, the reactivity increases and a power excursion will occur if the reactor is not scrammed. Consequently, preventing a power excursion is the focus of many plant control systems. Thus, a reactor trip occurs as a result of a turbine control or main steam isolation valve closure.

For PWRs a loss of load has an indirect impact on the reactor coolant system and tends to decrease the reactor power as the RCS heats up due to less efficient steam generator cooling. The BWR loss-of-load transient can have an immediate effect of rapidly increasing reactor power unless control actions are taken. Because of the potential power excursions, domestic BWRs are not designed to handle (not inserting scram control rods) a loss-of-load transient. For a load rejection at low power (<33%) the reactor does not automatically scram as a result of the turbine control valve closure since the steam bypass valve is sized to bypass an adequate amount of steam to the condenser. However, with several recent significant BWR power uprates, the bypass flow capacity has not changed with the power. Thus, it seems reasonable the ability to handle a loss-of-load event has been further diminished.

The advanced boiling water reactor (ABWR) design is able to handle a loss-of-load transient from full power because of recirculation flow control, vessel pressure control systems and a large steam bypass capacity designed specifically for that purpose. These systems are:

- a large steam bypass capacity (110% nominal steam flow)
- a recirculation flow control system (RFCS) that either trips the reactor internal pumps or rapidly decreases the pump speed to the minimum rate, and
- a steam bypass and pressure control system (SBPCS) that adjusts the turbine control valve and steam bypass valve to mitigate vessel pressure rise.

Upon a loss-of-load, the pressure rise is minimized by the SBPCS and the reactor power is decreases due to decreasing core flow which increases the core voiding due to RFCS actions.

Four ABWRs units are operational in Japan and two in Taiwan.

9.2 Overview of Loss-of-Load Transient for Various BWR Plant Designs

Since the operating domestic BWRs are a General Electric design, there is not the variety of systems that exists in PWRs.

There are five BWR designs currently operating. The basic reactor vessels designs are similar. Major differences include recirculation loops, power density, and containment. The designs are:

- BWR2 - Forced external recirculation with five loops, Mark I containment
- BWR3 - Two external recirculation loops that drive jet pumps in the reactor vessel, Mark I containment
- BWR4 - Same as a BWR3 with increased power density with either a Mark I or II containment
- BWR5 - Same a BWR4 with a revised recirculation flow control, Mark II containment
- BWR6 - Increased power density from the BWR5 , Mark III containment
- ABWR - Numerous changes and improvements from the older BWR designs. Internal pumps replace the recirculation loops and jet pumps. Analog reactor protections system and control systems are replaced with digital systems. The containment design has also been significantly improved.

For the purposes of this discussion, the BWR2 through BWR6 are referred to as BWR. BWRs have limited ability to handle a loss-of-load event due to insufficient bypass valve capacity (approximately 1/3 of nominal steam flow) and lack of vessel pressure control systems the minimize the pressure excursion

The BWR reactor protection system causes a reactor trip if any of the signals below occur.

- Turbine stop-valve or turbine control-valve closure (for power > than 33%)
- High neutron flux
- High reactor vessel pressure
- Main steamline isolation valve closure
- Loss of offsite-site AC power
- Low vessel water level
- High vessel water level (BWR6)
- High drywell pressure
- Low RPV pressure
- Seismic events

The main BWR control systems include:

- Control rods control
- Recirculation flow control
- Reactor pressure control
- Reactor water level control
- Turbine power control
- Turbine steam bypass system
- Reactor Protection system

Typically, the power is controlled by the control rod controller for less than 65% nominal power. Above 65%, recirculation flow rate controller maintains the desired power level.

The pressure control maintains the reactor vessel pressure at a desired setpoint. The pressure regulator maintains pressure by opening and closing the turbine governor control valve and the steam bypass valve. Under normal operating conditions, the turbine power control system regulates the turbine steam flow to meet the target load and target turbine inlet pressure by controlling the opening of the turbine governor valve. Should a load rejection occur, the turbine governor valve will close terminating flow to the turbine. The turbine steam bypass valve is controlled by the pressure regulator during normal operation. For a load rejection, an automatic steam bypass system is provided to dump steam to the condenser based on predetermined pressure setpoint. The steam bypass capacity was originally capable of maintaining vessel pressure and preventing a reactor trip at reactor power levels less than 30% to 33%.

ABWRs are designed to handle a loss-of-load at full power and reduce the power to house load. The bypass flow capacity is 110% of the nominal steam flow. The power is reduced by quickly reducing the core flow by the recirculation flow control system The recirculation flow control system quickly reduces core flow and reactor power and the vessel pressure rise is minimized through the actions of steam bypass and pressure control system.

9.3 Limitations in Current BWR and ABWR Designs

Because of the need to prevent the power surge during loss-of-load events, the reactor protection system and control designs are quite inflexible. Only at low power level, is it possible to have a load rejection without a reactor trip.

One of the following BWR reactor trip signals will actuate during this event to prevent a power excursion.

- Turbine stop-valve or turbine control-valve closure
- High neutron flux

- High reactor vessel pressure
- Main steamline isolation valve closure
- Loss of offsite-site AC power

ABWRs are designed to prevent a reactor trip during a loss-of-load event. Thus, there are no design limitations.

9.4 Discussion of Probability of Success in BWR Runback to House Loads

Successful BWR runback from nominal to house loads is less probable than most PWRs since a turbine trip triggers a reactor trip to prevent a power excursion. If the reactor were not tripped on a turbine control valve closure, the power could raise to three to six time nominal which would cause a reactor trip on high neutron flux. These reactor protection actions are required to prevent fuel damage. Current BWR designs would require modifications to the bypass flow capacity, the recirculation flow controller and vessel pressure controller to handle a loss-of-load event.

Fast acting ABWRs flow and pressure control systems minimize vessel pressure increase and prevent power excursions. The existing ABWR design can reduce power to house load during a loss-of-load event with no modifications.

BWR Complications of Concurrent Equipment Failures

The steam line safety valves must perform as designed to mitigate a high pressure trip. The bypass must function normally. The recirculation flow controller must decrease the core flow as quickly as possible to increase core voiding to offset the power excursion. As an example, if is the recirculation pumps are tripped, the core power can be reduced to approximately 30% of nominal.

Possible BWR Control Changes That Would Improve Success

Possible control actions would need to focus on increasing core voiding for a loss-of-load event. This could include immediately tripping the recirculation pumps and closing the feedwater control valves.

The control rod control controller is not active at full power. This controller could be modified to participate in a vessel pressurization event such as the loss of load to immediately lower the power to the bypass capacity.

The pressure control system could be modified to rapidly control the turbine valve and bypass valve to minimize the vessel pressure increase.

Note that the power excursion following turbine trip is very rapid, and reactor trip typically occurs in only a few seconds. This time-span gives perspective to the rapidity required of any control changes.

Possible BWR Mechanical System Changes That Would Improve Success

Increased bypass flow capacity with the possible control changes would help the system handle this event.

Appendix A Table A-1-Reactor Trip Events - Causes and Categorizations

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Arkansas 1	3132008001	12/12/2008	The most probable root cause of the dropping of the group 7 rods is the intermittent failure of the K1 and/or K2 ABT relays. The K1 and K2 relays were original equipment, and were found to be degraded. A possible root cause is a failure associated with the programmer assembly. The programmer assembly presents a single point failure vulnerability. The failure of the 15 V power supply (internal to the programmer assembly) would directly cause the failure of the Programmer Micro Controller Unit.	Rod Control	Electronic
Arkansas 1	3132008001	12/20/2008	The most probable root cause of the dropping of the group 7 rods is the intermittent failure of the K1 and/or K2 ABT relays. The K1 and K2 relays were original equipment, and were found to be degraded. A possible root cause is a failure associated with the programmer assembly. The programmer assembly presents a single point failure vulnerability. The failure of the 15 V power supply (internal to the programmer assembly) would directly cause the failure of the Programmer Micro Controller Unit.	Rod Control	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Arkansas 2	3682009001	3/13/2009	Investigation revealed that a valve positioner for the “B” MFRV had failed causing the valve to be driven in the closed direction. The MFRVs are controlled by Fisher Controls DVC6000 Series positioners. An integral part of the valve positioner is a current-to-pressure (I/P) converter that transforms an electrical signal to a pneumatic signal between the electronic control system and the air operated valve. The I/P converter was found to be sticking. Although a definitive Root Cause has not been found, the vendor believes that the condition was caused by a foreign substance in the clearance area of the armature, internal to the I/P converter.	FRV	Air
Arkansas 2	3682009005	12/8/2009	The thrust bearing failure was caused by excessive thrust loading. The equipment degradation causing the excessive thrust loading could not be definitively determined without an internal inspection of the pump; however, changes in hydraulic performance, combined with the thrust bearing inspection, indicate a potential defect or degradation associated with the pump internals.	FWP	Pump
Braidwood 1	4562010004	9/20/2010		RPS	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Braidwood 2	4572009001	4/24/2009	The Unit 2 reactor tripped due to a momentary/spurious signal spike on the 2D OTDT channel while the 2B OTDT bistable was in the tripped condition for 2B pressurizer pressure surveillance testing, making up the 2 of 4 trip logic. The investigation of this event found no issues with human performance, equipment failure, or plant activities that could have caused the signal spike. By using redundant channel coincident trip logic, the 2 of 4 logic (2 of 3 for some protective functions) design of the Reactor Trip System and Engineered Safety Features Actuation System (RTS/ESFAS) [JE] protects against unplanned or stray trip signals on a single channel, which would otherwise result in a reactor trip, while still capturing legitimate trip signals seen by multiple channels. However, this design is not fault tolerant. During maintenance activities, one channel is manually placed in the tripped position. This converts a normal 2 of 4 (or 2 of 3) logic into a more vulnerable 1 of 3 (or 1 of 2) logic. During a maintenance activity, an unplanned human error, spurious transient, or channel failure in a coincident channel initiates an inadvertent reactor trip or safeguards actuation. This design has resulted in several events within the industry including unit trips while at power. Therefore, the root cause of the Unit 2 reactor trip is determined to be the design of the RTS/ESFAS, which places a loop in a trip condition for testing, increases vulnerability during testing conditions.	RPS	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Browns Ferry 2	2602009001	2/16/2009	A. Immediate Cause The immediate cause for the event was the failure of the controller for temperature control valve TCV-35-54. The initial investigation found the controller unresponsive. B. Root Cause The root cause of this event was inadequate design of the stator cooling water system. The system contains single failure points that can potentially result in a generator trip and subsequent reactor scram. In this event, the temperature controller and TCV-35-54 is the single point failure that required the manual scram.	SCWS	Electronic
Browns Ferry 2	2602009007	9/29/2009	A. Immediate Cause The immediate cause of the event was the successive trips of reactor feedwater pump 2A, condensate booster pump 2A, and reactor feedwater pump 2C. B. Root Cause The cause investigation determined that the condensate/feedwater system operating instructions had been previously revised to allow operation at 100 percent power in a reduced pump configuration. The basis for the procedure change was the misapplication of a steady-state hydraulic design calculation.	FWP	Procedure

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Browns Ferry 3	2962007001	2/9/2007	A. Immediate Cause Reactor Scram The immediate cause of the reactor scram was a loss of control of the condensate demineralizer valves. During the maintenance activity both the primary and secondary controllers were placed in the program mode. With neither controller in the run mode, all of the demineralizer outlet valves closed and the bypass valves opened. The flow path to the condensate booster pumps was restricted for a short period, thus; causing the lowering of the reactor water level. Restart of Recirculation Pumps The immediate cause for the premature restart of Recirculation pump 3B was inattention to detail. Pump 3B was started following an unsatisfactory performance of 3-SR-3.4.9.3&4 (the reactor dome temperature to recirculation system loop B temperature was greater than the maximum allowed.) B. Root Cause Reactor Scram The root cause of this event was the individuals involved in the planning and implementation of the work order that provided instructions for establishing manual control of the condensate demineralized system did not fully understand manual operation of the system. The operating instructions for the condensate demineralizer system do not provide instructions for placing the system in manual operation, so the manual alignment was performed erroneously using a step-text work order. Since the work order was in error, those involved erroneously perceived that there was no risk involved in the manipulation of the controllers since they thought they had placed the system in the manual mode. Additionally, there is inadequate guidance or limitations on the use of in-field decision making. Even though the system did not operate as expected, the individuals involved proceeded with trouble shooting activities. Restart of Recirculation Pumps The root cause for the failure to follow the guidance in 3-SR-3.4.9.3&4 was the operator misread the implementing step 7.10. Step 7.10 states: Verify the difference between the coolant temperature and the recirculation loop to be started and reactor pressure vessel coolant is ≤ 50 degrees F. (Whenever in Mode 2 and both recirculation pumps are not in operation, the difference may be ≤ 75 degrees F.) The operator missed the clarification that ≤ 75 degrees F was only valid in Mode 2 with both pumps not in operation. The operator keyed in on the value, 75 degrees F.	Condensate	Error

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Browns Ferry 3	2962009001	8/24/2009	A. Immediate Cause The immediate cause of the event was the failure of all ten of the Unit 3 condensate demineralizer remote communication chassis. B. Root Cause The root cause was determined to be the less than adequate functional testing of the condensate demineralizer system valve lock-up devices.	Condensate	Electronic
Brunswick 1	3252010003	5/5/2010	The cause of the event was pulsation dampeners (i.e., with pins installed) in the reactor feed pump suction flow element sensing lines, installed in a 1977 plant modification, delayed the actuation of the low suction flow signal to the pump runback logic. This delay allowed the RPV water level to drop below the Low Level 1 setpoint, causing an automatic reactor scram on Unit 1 and activation of the RPS and the PCIS. The investigation concluded that the adverse condition was a historical problem, which has existed for such a long time that a plausible root cause could not be reasonably determined.	RPS	Design

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Cook 1	3152007001	8/28/2007	The design of the DCS failed to ensure that DCS Power Supply Trip Set points were adequate to ensure that a degraded/failing power supply would not cause loss of downstream components, such as the feed pump control cards, prior to the power supply tripping and transferring the downstream loads to the alternate power supply. In February 2007, CNP recognized that the DCS power supplies were temperature sensitive and that one power supply was degraded. Cabinet air conditioning was installed to ensure the power supplies were maintained within an acceptable temperature band. The failure of the DCS cabinet air conditioner in August 2007 resulted in elevated temperatures within the DCS cabinets, which in turn caused the degraded power supply to produce an over voltage condition. This failure created an elevated output voltage from the power supply, which ultimately resulted in the tripping of the controller for the East Main Feed Pump. This adverse impact on the Main Feed Pump controllers was not previously considered in the design or previous valuation-of the degraded power supply. Therefore, actions were not implemented to replace the power supply prior to the next scheduled refueling outage.	FWCS	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Crystal River 3	3022007002	2/21/2007	The cause for this event was inadequate human performance in the implementation of the ICS circuit card refurbishment program which resulted in an age-related failure of the zener diodes in the +15 volt regulatory circuit for a Bailey 820 Control Module in the ICS. On March 24, 2004, the plant tripped due to the failure of ICS Module 3-8-4 [JA, IMOD]. The resulting corrective action plan installed refurbished multipliers in four critical ICS locations and established a refurbishment program for all ICS modules. In November 2005, the refurbished replacement for ICS circuit card IC-384-IC failed calibration. This was discussed between the maintenance technician and the system engineer during turnover. The system engineer decided to install a non-refurbished multiplier card into the IC-384-IC since no refurbished spares were available at the time. The system engineer was fully aware of past actions to use only refurbished cards and he intended to ensure follow up activities. However, the turnover of this decision was incomplete in that supervisory personnel were not notified, and no follow up actions were taken to ensure that appropriate compensatory measures were established to install a refurbished multiplier card at the first available opportunity.	FWCS	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Crystal River 3	3022008003	8/24/2008	The root cause for this event was inconsistent and misunderstood requirements for the FW booster pumps [SJ, P1]. The Shift Technical Advisor made a recommendation to the Superintendent Shift Operations (SSO) to consider entry into AP-510 based on FWHE-1 level at approximately 8 feet in level. The SSO considered the FWHE-1 level to be a concern but thought there was margin until FW booster pump cavitation. The perceived margin came from the Limits and Precautions in Operating Procedure OP-605, "Feedwater System," Section 3.2.11, which stated that operation of FW booster pumps < 6 feet FWHE-1 level "should be avoided." OP-605 specified a FW booster pump automatic trip setpoint of -- 2 feet and 10 inches level in FWHE-1. The operating crew believed that FW pump cavitation would not occur until FWHE-1 level approached the trip setpoint. This inconsistent guidance, along with slow diagnosis of the CDP-1A loss, resulted in not entering AP-510 in a timely manner. Cavitation of both FW booster pumps and Main FW pumps occurred at approximately 4.75 feet FWHE-1 level and caused the loss of FW flow control to the OTSGs.	Condensate	Pump

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Crystal River 3	3022009001	1/27/2009	Two causes have been identified for the need to manually trip the reactor. The first cause was improper use of human performance tools which led to the connection of the incorrect test leads to the 'A' 4160V Unit Bus. The three causal factors for this human error were: 1) self-checking not applied to ensure correct intended action; 2) failure to effectively use peer checking; and, 3) procedure use and adherence failure (i.e., performance of the voltage check outside of the work order guidance). The second cause was inadequate closure of corrective actions for a similar event that occurred at CR-3 in 2004 (Priority 2 NCR 133661). The CR-3 Plant Nuclear Safety Committee (PNSC) established an action to: "Add a corrective action to complete a risk assessment for this type of work (calibrating volt meters on the main control board), whether it should be completed on-line vs. off-line." The response to this corrective action was not adequate and was not reviewed by the PNSC or the PNSC Chairman. This resulted in the failure to move relay activities that could result in a plant transient from on-line to outage.	Non-1E 4KV	Error

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Crystal River 3	3022009003	8/24/2009	The unexpected drop of the Group 7 control rods was due to the failure of the programmer caused by inadvertent test jumper contact during PM-i 26, using an improperly fused test jumper. These two conditions caused an over-current failure of the output driver within the Group 7 CRD programmer, causing an erroneous phase sequence to the control rod drive stators, culminating in inadequate magnetic force to restrain the rods from dropping during movement. The improper placement of an improperly fused jumper is a combination of two inappropriate acts. Since a proper fuse in the test jumper alone would have prevented the event, it is considered to be the root cause for this event. PM-126 directs use of a fused jumper, with a current limit of 0.1 amp. The jumper fuse was checked and found to be a 1.0 amp fuse. This is not consistent with the procedure, and is not adequate to protect the associated equipment which has a maximum current rating of 0.5 amp. The jumper made inadvertent contact with a positive voltage/current source. It is feasible that the contact was momentary, and unknown to the worker, as the jumper may have simply brushed across an adjacent terminal on the way to the intended terminal.	Rod Control	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Dresden 2	2372007002	5/4/2007	The root cause of the unexpected closure of all Unit 2 Condensate Prefilter System valves and the subsequent loss of feedwater transient was a vendor latent software deficiency that caused the valves to close when the new Condensate Prefilter System CPU card was energized. Pre-operational testing in 2001 of the Unit 2 Condensate Prefilter System identified the system was not operating as expected as the system periodically initiated auto-bypassing the Condensate Prefilters from power supply perturbations. DNPS requested the software contractor to perform a software revision to alleviate the power supply perturbation effects. Based on the Exelon request, a contractor programmer performed a logic change which implemented the "0-1" logic for Condensate Prefilter System valve alignment. This revision utilized registers for valve position with zero for closed and non-zero for open. The revised software retained a memory of the valve positions prior to the last-known position. The original intent of the software revision performed as designed since implementation in 2001 as demonstrated by the periodic soft reboots to reset the CPU. The investigation of this event identified the programmer implementation of the "0-1" logic for valve alignment introduced an unrecognized latent software deficiency under which all valves could be sent a closed signal. The latent software deficiency was not apparent during the post-modification testing and normal system operation, including CPU re-boots. The condition only manifests when the all CPU registers contain a "0" resulting from a lack of previous valve positions in the CPU memory. All registers would contain a "0" when a new CPU card is installed. The vendor was unaware of the existence of the software deficiency until discovered during the post-analysis of this event. DNPS operations personnel on May 5, 2007 identified during operator rounds, that the Unit 2 Condensate Prefilters were bypassed. Further investigation identified the Unit 2 Condensate Prefilter System CPU card had failed. DNPS initiated work to replace the CPU card. This was a first time evolution, as the Condensate Prefilter System CPU card had not been replaced since initial system startup. Upon energizing the CPU card, all the Condensate Prefilter System valves were given a closed signal due to the new CPU registers all containing a "0." The closure of all Condensate Prefilter System valves caused a loss of feedwater transient and the resulting need to manually scram the reactor.	Condensate	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Dresden 3	2492009001	10/3/2009	The Probable Cause for the pressure pulse initiating Reactor Water Level Low-Low Group I Isolation Signal and Unit 3 Reactor SCRAM is attributed to a latent procedural deficiency. DOP 1200-03 provided inadequate guidance for the 3-1201-7 valve position during system restoration with the RPV at pressure. In GEK-323399, "Dresden 3 Reactor Water Clean-Up Operation and Maintenance Instructions," Section 3-11, the reactor vendor, General Electric, recommended that the Return to Reactor line MOV be in the open position for RWCU system start-up when the reactor is at power. This recommendation was not incorporated into DOP 1200-03. The procedure deficiency is historical. The Cause of the Unit 2/3 EDG automatic start when auxiliary power transferred to the reserve power source is due to breaker contact response timing. During the fast transfer between the main and reserve feed breakers to the 4 kilovolt (kV) Bus 33, the "b" contacts on both the breakers (which are connected in series) were closed simultaneously for approximately 74 milliseconds. This provided sufficient time for the auto start relay of the Unit 2/3 EDG to be activated. Even though the EDG autostart was not expected, it is possible as there is no delay mechanism built into the electrical circuitry to absolutely prevent the autostart during a fast power transfer. The potential for EDG actuation in a particular situation depends on the relative speed and timing of the "b" contacts for the main and the reserve feed breakers to go from "closed" to "open" and from "open" to "closed," respectively.	FRV	Procedure

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Dresden 3	2492010001	10/11/2010	The half-scram signal that occurred on 'B' RPS was generated from the when the 3-0590-107F relay de-energized. This relay is associated with the Nuclear Instrumentation portion of the RPS system. This relay is associated with Intermediate Range Monitor (IRM) 16, Average Power Range Monitor (APRM) 6 and Oscillation Power Range Monitor (OPRM) 6. With the Mode switch in RUN, the IRM was bypassed and could not generate a trip signal. The operating procedure that was being used to transfer the RPS bus, DOP 0500-03 Reactor Protection System Power Supply Operation, contained a prerequisite to place APRM 6 in bypass prior to commencing the bus transfer. The OPRM was the only active component in the 107F relay string. Troubleshooting indicated that OPRM 6 had no power. Further investigation revealed that the input fuse had blown on the OPRM power supply causing it to lose output power. Initial examination of the circuit board, did not reveal any failures of board components other than the blown input fuse. The board was sent out for additional testing. No defects were identified besides the blown input fuse. The fuse was replaced and the power supply was successfully turned on. All indications were within expected ranges. Following seventy-two hours of operation, no defects were identified. The power supply was sent for a detailed failure analysis. A failure analysis of the power supply indicates that the OPRM 5 VDC power supply is susceptible to electrical noise. The power supply is designed with a circuit (Crowbar Circuit) which senses voltage transients and prevents the voltage excursion from damaging voltage sensitive components downstream of the power supply output. When a voltage spike occurs, the crowbar circuit is activated, which essentially shorts the circuit to ground and blows the input fuse. This results in the power supply being turned off thus terminating the voltage transient on the down stream components. Efforts have been made to identify the source of the electromagnetic interference. However, the source has not been identified at this time. Investigations and failure analyses are continuing in order to mitigate the effects of electromagnetic interferences on the OPRM power supplies.	RPS	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Duane Arnold	3312007007	4/2/2007	An investigation into this event was completed under Root Cause Evaluation (RCE) 1065. Overall RCE Conclusions The human performance investigation conducted did not identify any discrepancies or inappropriate actions on the part of those involved in the field work or the control room crew on the day of the event. Although not specifically targeted, equipment failures (relays, wiring, and panel configurations) were investigated. For the logic to be met (1A2 bus lockout) one of eight relays, or the lockout relay would have had to change state. Relays were sent off to an independent lab for testing. Detailed troubleshooting activities did not identify any source or cause that was consistent with or leading to the event. Given the fact that no equipment failures were identified, a human performance event (bumping or error) would be the likely cause of the actuation. The RCE identified the main contributor of the event to be an organizational failure. Specifically, the organization failed to recognize the risk associated with performing the maintenance on-line without putting physical and process protections in place. Contributing to this cause was the successful performance of this maintenance on several previous occasions. Root Causes An organizational failure, which allowed work on a system with the risk potential for plant impact is considered to be the cause of this event. The failure was the lack of the organization to recognize the risk and place physical and process protection associated with performing the maintenance on-line. Contributing to this cause was the successful performance of this maintenance on several occasions previously. A human performance event (bumping or error) would be the likely cause of the actuation.	Non-1E 4KV	Error

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Duane Arnold	3312009003	4/3/2009	A root cause evaluation (RCE 1081) was completed for this event. The RCE determined that the revision to STP 3.3.3.2-09 introduced a latent error that removed the recorder from service, and interrupted the control loop. The specific root causes (RC) and contributing factors (CF) are as follows: RC1- Electrical termination changes in STP's are not reviewed with the same requirements as maintenance activities. RC2 - The site modification process does not require review of all service requirements, including how equipment is to be calibrated and tested while the unit is operating.	RPS	Procedure

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Duane Arnold	3312009004	10/8/2009	A Root Cause Evaluation (RCE 1086) was completed for this event. The RCE determined that the shutdown was caused by the failure to close an instrument isolation valve for a Reactor Vessel Pressure Transmitter PT4564. The failure to close this valve resulted in creating a sensed low reactor water level on Reactor Protection System (RPS) channels A2 and B2, and thus resulted in the automatic reactor shutdown. The specific root cause and contributing factors are as follows: Root Cause: Defenses in depth were inadequate to prevent the plant transient, when the IC Technician did not completely close PT4564 V-92 during the performance of Step 7.1.62 of STP 3.3.3.2-09B.	RPS	Error
Farley 2	3642007001	10/3/2007	This event was caused by a testing procedure that lacked a step to block the High Voltage Switchyard (HVSY) breaker failure sequence relays. The failure to block resulted in the breaker failure sequence relays actuating. The breaker failure sequence relays tripped the associated HVSY breakers, which then de-energized the 2B Startup Transformer. Loss of the 28 Startup Transformer ultimately led to loss of RCP Breaker Indication relay (1 out of 3 coincidence), resulting in Unit 2 reactor trip. The de-energization of the 28 Startup Transformer was caused by a loss of feed associated from the HVSY breaker failure sequence relay actuation and an Auto Bank transformer being removed from service for maintenance.	1E 4KV	Procedure

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Farley 2	3642010002	5/22/2010	The NCO card (C8-330) in process control cabinet 8 of the 7300 system failed causing the 2C SG FRV to close. The NCO card malfunction was due to a S1-1 Silicon Controlled Rectifier (SCR) failure. The root cause investigation team, with support of the vendor, found only one other industry occurrence where this component failed. The NCO card supplies power to the 2C SG FRV controller and controller power was lost when the card failed. Without controller power the 2C SG FRV closed and could not be operated in either manual or automatic mode. A manual Unit 2 reactor trip was initiated at approximately 40% narrow range level in the 2C SG.	FWCS	Electronic
Grand Gulf 1	4162007003	8/21/2007	On August 21,2007 Instrumentation and Controls (I&C) technicians were taking power supply voltages and alternating current ripple measurements in the "A" Bailey INFI-90 digital Feed Water [SJ] control panel. The technicians had completed taking a reading and were in the process of removing their probes from the panel when they noticed an arc followed by the sound of relays changing position resulting in an unexpected Power Failure Interrupt (PFI) signal being generated.	FWPT	Error
Grand Gulf 1	4162008004	10/23/2008	The cause of the event was that the NLO did not use the self checking standard of TOUCH-READ-READ which involves touching the component intended to be manipulated, reading the tag, and reading the procedural step to verify the correct component was about to be manipulated. The NLO also did not use the required circle and slash method of place keeping.	FWPT	Error

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Grand Gulf 1	4162010001	3/8/2010	The root cause of the event was determined to be a lack of adequate work instructions for: (1) installing outer jacket sealing on cable splices, and (2) inspection and lubrication of rack and pinion gears. The cause of the event was the combination of the Reactor Feed Pump 8 (RFP B) minimum flow valve failing open due to an erroneous signal from flow instrumentation, and the Reactor Feed Pump Turbine A (RFPT A) tripping due to speed demand mismatch caused by control valve linkage binding.	FWPT FWP	Valve Electronic
Hatch 1	3212008003	7/4/2008	This event was caused by a sensed low pressure in the EHC system tripping the turbine which resulted in an automatic reactor scram. The turbine trip was the result of the combination of the following modifications. A new Mark VI turbine control system was installed in Spring 2006. During that modification the point at which the pressure sensors tap off of the EHC line was changed from the manifold where accumulators are attached to the smaller tubing which also feeds the auto start solenoid valve, this resulted in a larger sensed pressure drop during testing. The digital pressure transmitters which were installed with the original Mark VI modification were changed to analog transmitters during the Spring 2008 refueling outage. The analog transmitters have a significantly faster response time of 100 ms compared to the 225 ms response time of the digital transmitters.	EHC	Design

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Hatch 2	3662007008	8/7/2007	The root cause of this event was determined to be ineffective execution of a screening procedure written to determine scram/transient potential of I&C activities. The screening procedure was executed for the calibration of the overcurrent relay and errantly determined that there was no reactor trip potential when performing the procedure on-line and did not include a precaution for installation of the relay cover.	Non-1E 4KV	Relay
Hatch 2	3662009004	6/23/2009	The cause of this event was the failure of an internal power supply electrolytic capacitor on the power supply board which caused a failure of the DC power supply for the Yokogawa level controller 2C32K648. During recovery efforts it was determined that the 2C32-K648 controller was not responding to reactor water level increases and was displaying the error code P.error. Per the Yokogawa vendor manual, this is indicative of an internal power supply failure. The P.error code was intermittently displayed during the recovery process. The controller was removed from service and transported to the Maintenance lab for analysis. Power was applied to the controller, and the P.error code was again displayed. This error was intermittent during the analysis period. Internal inspection of the power supply identified a failed electrolytic capacitor.	Non-1E 4KV	Procedure

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS **Table A-1**					
Unit	LER	Event Date	Cause	System	Category
Hope Creek 1	3542007002	5/29/2007	The root cause of the unexpected bus transfer could not be conclusively determined by the investigation. There are two potential causes to the initiating event that are being addressed. The timer stop timing module test leads may have been left in place from a previous procedure step creating a low impedance path to satisfy the logic path. It was noted that if the test leads had not been properly removed in the correct sequence, then the unexpected slow (dead bus) transfer would occur.	1E 4KV	Error
Indian Point 2	2472007004	2/28/2007	The direct cause of the RT was loss of main feedwater (FW) flow. The cause of the low FW flow was failure of the power supply (PQ-408B) for the MBFP suction pressure transmitter (PT-408B). The power supply failed due to a failure of its filter capacitors (Cl and C2) as a result of age degradation. The root cause of the power supply failure was insufficient verification of the existing plant programs to address capacitor age degradation due to human error.	FWPT	Electronic
Indian Point 2	2472008001	3/23/2008	The direct cause of the malfunction of the MBFP Lovejoy control system was the RFI from an energized camera due to close proximity either from the camera digital circuitry itself or from the electrical discharge of a large capacitor through the xenon flash tube, which interfered with the Lovejoy control system for MBFP speed control. The root cause was a lack of knowledge that a digital camera is a source of RFI which, when within a critical range, for critical digital equipment can cause adverse effects. The CR staff and Planner were not aware that just having a digital camera turned on in close proximity to other digital equipment could cause a problem. Although RFI is a known phenomenon with a potential for un-intentional effects on electronic equipment, digital photography as an RFI source was not recognized or understood.	FWCS	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Indian Point 2	2472009002	4/3/2009	(MBFP) 21 due to an autostop oil tubing/Swagelock fitting failure on the MBFP Autostop oil header. A straight section of autostop oil tubing connected to a bulkhead fitting in an oil reservoir for the 21 MBFP Autostop oil header fractured behind a back ferrule swage. The fracture caused a drop in oil pressure below the Autostop oil header trip set point. The root cause was improper tubing installation due to poor worker practices. The cause of the turbine runback failure was indeterminate but most likely an intermittent failure of the digital speed tachometer assembly.	FWPT	Hyd
Indian Point 2	2472010007	9/3/2010	The direct cause of the RT was a turbine generator trip due to a high 23 SG level. The root cause was inadequate design control of the proportional band and reset tuning settings for critical plant controllers.	FWCS	Electronic
Indian Point 3	2862009004	5/28/2009	The direct cause of the RT was a TT from a high SG-32 level. The cause of the high SG level was overfeed of the 32 SG by the 31 MBFP due to the inability of the 31 MBFP turbine to operate at higher speeds on HP steam and due to the 32 FRV SG water level controller (LC) going into saturation. The limited ability of the 31 MBFP to operate on HP steam was due to improper HP governor valve stroke. The root causes (RC) for the RT were: RCl) Ineffective problem solving.	FWPT FWCS	Valve Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Kewaunee	3052007001	1/12/2007	No root cause could be conclusively identified. Foreign material on a valve-seating surface was identified as a probable cause.	EHC	Hyd
Kewaunee	3052007004	2/27/2007	For the trip, the most probable root cause has been determined to be the combination of relay contact failures caused by: * Poor circuit design * Manufacturing defects in some installed relays * Substandard installation practices The apparent cause of MS-201 B1 sticking at 100% open was determined to have been excessive wear in the valve lower plug guide at the bushing. The valve guide had 0.143" wear due to the large clearance between the guide to the bushing and old style bushing. This wear created a ledge for the guide to latch onto the bushing while the steam flow pushed the plug/guide into the bushing.	RPS	Relay
La Salle 2	3742009001	8/15/2009	The cause of the Main Turbine trip was a failed communication chip on the VCMI card in the DEHC system. The root cause of the event was the failure to adequately understand the impact of a diagnostic alarm from the VCMI card, due to a lack of vendor information.	EHC	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Limerick 1	3522011002	6/3/2011	The root cause of the event was the reactor vessel high level trip calibration and functional surveillance test revisions did not fully assess the impacts of the test equipment on the DC turbine trip circuit.	RPS	Procedure
Limerick 2	3532007003	4/24/2007	The scram was caused by an intermittent failure of a circuit card in RRCS division 1B concurrent with ongoing testing on division 1A that caused a reactor feedwater runback. The flow oscillations on HPCI and RCIC were caused by improper flow control loop setting adjustments of gain and reset.	RPS	Electronic
Limerick 2	3532011004	5/29/2011	The root cause of the event was a void in the electrohydraulic control oil supply line that resulted in a perturbation of the oil supply pressure at the adjacent control valve.	Turbine	Hyd
McGuire 1	3692011002	1/20/2011	The root cause for the lB CF pump trip was the use of equipment for a purpose it was not designed. Specifically, the use of the gate valve for throttling purposes. This placed reliance on operator actions and procedure guidance to control critical operating parameters while transferring steam supplies to the lB CF pump.	Condensate	Procedure
Millstone 2	3362008005	6/28/2008	Ineffective configuration control of parts allowed parts to be installed in a feedwater level control valve [LCV] causing it to operate incorrectly. This resulted in divergent feedwater heater level oscillations. The heater oscillations resulted in both main feedwater pumps to trip, requiring the operators to manually shutdown the reactor.	HDLC	Valve

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Millstone 2	3362010002	5/22/2010	The cause of this event was determined to be vibration induced worn threads on the number 2 feedwater regulating valve (2-FW-51 B) positioner beam screw.	FRV	Air
Millstone 2	3362011002	6/20/2011	The cause of the event was gaps in the application of operator fundamentals and some procedure quality issues associated with operations procedure OP 2204, Load Changes.	FWP	Error
Millstone 3	4232008003	10/11/2008	The cause was determined to be the operating crew on shift failed to effectively use the tools necessary to enable an event free shutdown of the plant.	FWCS	Error
Millstone 3	4232010002	5/17/2010	The cause of this event was determined to be the inability of the FRBV control system to control S/G levels at low power operations	FWCS	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Monticello	2632011009	11/19/2011	The direct cause of the scram was the actuation of the Main Turbine acceleration relay (load rejection) pressure switches. The root cause is ineffective management of turbine lube oil (TLO) tank vacuum which resulted in oil build up on the turbine shaft resulting in fouled grounding braids. Oil and oil mist combined with dust and dirt and increased contact resistance degraded the effectiveness of the shaft grounding device. Operator round sheet had ineffective control bands for lube oil tank vacuum. TLO vacuum instrument calibration band and accuracy did not allow operator to make an accurate assessment of the condition. The purpose of the shaft grounding device is to prevent damage to turbine generator components caused by circulating currents. Resulting circulating currents degraded the speed governor drive gear which resulted in governor bobble that manifested itself during speed load changer testing and caused pressure oscillations at the acceleration relay (load rejection) pressure switches.	Turbine	Error

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Nine Mile Pt. 1	2202009003	10/5/2009	In the spring 2009 refueling outage, a Control Components, Inc. (CCI) QuickTrak II system was installed for the shaftdriven feedwater pump FCV. This system consists of a pneumatic digital valve controller and a high-capacity servo valve positioning device. The root cause of the event was a programming error in the vendor-supplied firmware logic that prevented the proper operation of the transfer function of the FCV positioner when the operating positioner spool became mechanically bound. Instead, the FCV continued to open and raise reactor water level despite being given four close demand signals. It was determined that the most likely cause of the positioner spool binding would have been a very small particle of foreign material (FME), not visible to the human eye. No FME was actually found inside the positioner during the post-scram inspection.	FWCS	Electronic
Nine Mile Pt. 1	2202010001	11/10/2010	The November 10, 2010 scram was the result of the combination of two latent preexisting plant conditions and performance of a quarterly instrument channel surveillance test. The first preexisting condition was misaligned connector pins on the Grayboot splice connectors found in the power circuit of the outboard MSIV Channel 11 SOVs. The second preexisting condition was a misaligned contact spring in isolation logic Channel 12 relay 12K74 which was installed in April 2005. The cause of the misalignment has been determined to be excess material (plastic) left on the contact spring holding peg during fabrication of the relay's movable contact holder.	ESFAS	Error Relay

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Nine Mile Pt. 2	4102010001	1/7/2010	The direct cause of this event was venting of RHS instrumentation during planned maintenance. The root cause of this event is, Operations Management has not sufficiently monitored and reinforced standards associated with plant impact assessment during work planning.	RPS	Error
North Anna 1	3382007001	1/3/2007	Cause of the automatic reactor trip was the "B" SG low level coincident with a steam flow greater than feed flow mismatch. The initiating signal was caused by closure of the "B" MFRV. Closure of the "B" MFRV was the result of a failure of the final control card. The initial failure of the final control card, Westinghouse 7300 Process Control Card type NCB located in C7-331 which corresponds with mark number 01-FW-FCV-1488, was a shorted capacitor (C42). The root cause of this event is the Organizational and Programmatic Deficiencies that allowed the card to be placed in service in September 2004 without the new upgrades.	FWCS	Electronic
Oyster Creek	2192007001	7/17/2007	The cause of the "C" RFP trip is attributed to an internal motor ground fault. This motor was original equipment having never been replaced. The motor was scheduled to be replaced during the next refueling outage (1R22) in 2008.	FWP	Motor
Palisades	2552007005	5/8/2007	During maintenance, technicians inadvertently de-energized a MFRV controller causing it to close. The feedwater system attempted to recover but was not able to maintain S/G level.	FWCS	Error

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Palisades	2552008001	1/13/2008	The immediate cause of the main feedwater pump trip was low lube oil pressure. The low lube oil pressure resulted from the loss of the main feedwater pump's shaft-driven lube oil pump, which occurred when its drive coupling became disengaged.	FWPT	Pump
Palo Verde 3	5302011001	1/19/2011	The cause of the event was a failed diaphragm in the precision relay for the mini-flow valve control loop which resulted in the opening of the mini-flow valve on MFWP A. This allowed a percentage of feedwater flow to be diverted to the condenser, resulting in a MFWP B trip and a RPCB followed by a reactor trip and AFAS.	FWP	Pump
Perry	4402007001	5/15/2007	The cause of the automatic RPS actuation is attributed to the decrease in the RPV coolant level associated with Reactor Feedwater System testing/tuning activities. The RPV coolant level decrease was caused by a design logic error within the design modification to the DRFPTSCS. The design logic error did not allow the feedwater control system to respond correctly in order to automatically maintain the proper RPV level. The design logic error was not identified prior to testing the system on line due to a weakness in the owner acceptance review process.	FWCS	Design
Perry	4402007004	11/28/2007	The Turbine. Control Valve Fast Closure RPS signal was caused by a failure of both DFWCS power supplies: Failure of the DFWCS power supplies de-energized two feedwater control relays and supplied an invalid Level 8 signal to the main turbine system. The invalid signal caused the turbine control valves to ‘fast' close resulting in an RPS actuation signal. The reactor shutdown automatically and was not the result of operator actions.	FWCS	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Point Beach 1	2662007004	6/5/2007	A manual reactor trip was initiated due to the loss of a nut with subsequent inability to control steam generator level. The cause for the loss of the nut has been determined to be a procedure inadequacy. Vendor technical bulletin information on the use of the specific type of locknut on positioner linkages was not completely incorporated into plant maintenance procedures.	FRV	Air
Point Beach 2	3012010002	7/9/2010	The cause of the manual trip was a failed range diaphragm assembly inside the Bailey (B040) Model AP4 valve positioner. This failure allowed the valve to move to the full open position.	FRV	Air
Prairie Island 1	2822008002	7/31/2008	The equipment root cause for the failure of the F delta Q controller is attributed to the random failure of varactor diode (CRI) located inside the controller. Although this controller was refurbished in 1985, only the capacitors were routinely replaced as part of refurbishments. Therefore, CR1 was not replaced as part of the 1985 refurbishment. The organizational cause was found to be the inadequate prioritization by the site in the creation of a preventive maintenance strategy for the analog components within the reactor protection and control system.	RPS	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Prairie Island 2`	3062007001	4/5/2007	The root cause evaluation (RCE) of this event determined that the equipment root cause was due to high contact resistance on the contact of the safety injection relay which did not allow enough current to reach the reset coil of the relay and the relay did not reset. This caused a safety injection actuation and reactor trip when the system was taken out of test. The RCE further determined that the organizational root cause was due to lack of developing and implementing a preventive maintenance strategy for the MG-6 style relays in the RPS.	ESFAS	Relay

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Quad Cities 2	2652010002	8/17/2010	The cause of the 2B ASD trip and subsequent 2B recirc pump motor trip was that re-synchronization of the 2B ASD 'B' PLC was performed with the ASD control key switch in the remote position while a communication loss from the 'A' PLC already existed. The re-synchronization caused the ASD logic to trip the 2B ASD and the 2B recirc pump motor per design. Had the ASD key switch been in the local position, the logic in the ASD software would not have caused the 2B ASD to trip. The cause of the increasing reactor water level was due to the rapid steam flow / feedwater flow mismatch when the 2B ASD tripped the 2B recirc pump motor. Water level increases continued since the 2B FRV was in manual, and transferring the 2B FRV to automatic did not allow a sufficient valve closure rate due to a fixed ramp rate for closure (0.2% per second). The root cause of the recirc pump trip and subsequent reactor scram is management's failure to recognize and effectively challenge critical assumptions used in authorizing work activities for performing the ASD resynchronization, and in determining risk for the 2B FRV. Both process reviews failed to adequately assess and manage risk prior to performing these activities.	Rx Recirc	Error

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
River Bend	4582007005	9/26/2007	Engineering and maintenance personnel found that wiring and a terminal board in an RPS pilot scram solenoid circuit had sustained severe thermal damage. This failure had interrupted power to the Division 2 coils on the Group 2 pilot scram solenoid valves, in effect causing an undetected Division 2 half-scram signal for the Group 2 control rods. When the surveillance test inserted the half-scram signal in Division 1, the logic for the Group 2 control rods was completed, and the rods inserted as designed. A detailed examination of the components determined that the most likely cause of the thermal damage on the terminal board was a loose screw connection on one of the attached wiring lugs. No history of maintenance or testing could be found that might have required the wire to be lifted and re-terminated. It appears likely that the terminal screw had not been sufficiently tightened during plant construction.	RPS	Electronic
Robinson 2	2612009003	11/6/2009	The cause of this event was determined to be due to a vendor design error that resulted in premature part failure in the power supply for the Feed Regulating Control Loop FC-478E. A causal factor that contributed to this event was a lack of documentation regarding design issues with the EnsignTm Power Supply-Revision 3 by the vendor.	FWCS	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Robinson 2	2612012004	3/28/2012	As documented in Engineering Change 85951, the most likely cause of the Feedwater Regulating Valve FCV-488 going fully open was dirty contacts on selector switch 1/FM-488B [HS] that caused the feed water flow signal to drop to zero. It was determined in CR 527203 that the site failed to recognize the need for preventive replacement of low wattage control switches based on the guidance in the Control Switch PM Basis Template, and the apparent lack of site Operating Experience (OE) indicating the need for preventive replacement.	FWCS	Electronic
Salem 1	2722012001	4/30/2012	The SI actuation was caused by a failure of SSPS Train A logic. Troubleshooting and testing did not identify a definitive cause for the failure as the inadvertent SI signal could not be replicated. The apparent cause of the inadvertent SI was identified as induced noise on the SSPS 15 volt logic circuit.	ESFAS	Electronic
Salem 2	3112007003	8/6/2007	The direct cause of the reactor trip was a failed SSPS Train "A" output driver card A517 due to a defective solder joint. The defective solder joint was made during card refurbishment in September 2006 by PSEG maintenance. The root cause of the failed SSPS Train "A" output driver card A517 circuit card has been attributed to inadequate post soldering test practices in that the post soldering test and inspection was not comprehensive enough to identify the defective soldering.	FWCS	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Salem 2	3112008002	5/9/2008	The loss of power to the CW traveling screens that resulted in the initial plant power reduction was due to water intrusion into the electrical control panel during a period of heavy rain. The cause for the main feedwater regulating valve swapping to manual was determined to be the result of the 23 Steam Generator steam flow input signals decreasing (spiking) to below their predetermined low sensor limit. The steam flow signal spike was caused by a pressure wave initiated from the main turbine stop valves closing when the turbine was manually trip per procedure.	FWCS	Electronic
Salem 2	3112010002	1/21/2010	The cause of the tripping of the 21 SGFP was determined to be an internal wiring short in the SGFP trip control circuit that resulted in a false electrical trip signal. The short circuit occurred due to the barrel of the lug for the normally closed contact coming in contact with the terminal screw of the normally open contact resulting in failure of the electrical insulation on the barrel. The cause for the wiring short was the result of poor work practices. The reactor tripped on low water level in the 22 SG as designed. The low level SG trip setpoint as evaluated in the accident analysis is set at a level to ensure that adequate heat removal is maintained following a loss of normal feedwater. To increase the reliability of plant operations in response to a trip of a single SGFP, Salem installed an automatic plant runback feature in the 1990s. This feature is not credited in the accident analysis. Testing and evaluation following the 22 SG low level reactor trip determined that the systems responding to-the loss of a single SGFP operated as designed but did not prevent the reactor trip from occurring.	FWCS	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Seabrook	4432011002	10/6/2011	The root cause of the air intrusion into the condensate system, which resulted in a trip of the main feed pump and the subsequent reactor trip, was the lack of a procedure for restoring a condensate pump to service during operation at power.	Condensate	Procedure
Sequoyah 1	3272008001	1/16/2008	The immediate cause of the event was closure of the Loop 3 main feedwater regulating valve as a result of an error during performance of a calibration procedure. The closure of the feedwater regulating valve resulted in a low steam generator level. The root cause was determined to be a failure to follow procedure because of personnel not performing proper place keeping during performance of a calibration procedure.	FWCS	Error
Sequoyah 1	3272009005	5/6/2009	The diaphragm failure is attributed to an improper clamping force of the diaphragm to the actuator stem. This insufficient clamping force was a result of insufficient torque applied to the fastening screw. The insufficient clamping force allowed stress concentrations at the diaphragm hole, which caused an initial tear in the diaphragm composite material and led to an instantaneous failure of the diaphragm. The immediate cause was the failure of the Loop 1 feedwater regulating valve air operated diaphragm. The root cause of the equipment failure and subsequent reactor trip was determined to be that the governing vendor manual control procedure does not consider applicability to critical components.	FRV	Air

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Sequoyah 1	3272010002	11/16/2010	The cause of initiating a manual turbine trip was a MSR relief valve lifted because of foreign material lodged between the seat and the disk of the gland sealing steam check valve. The immediate cause of the reactor trip was that following the turbine trip the main steam dump valve controller did not operate to control steam flows. This led to a manual reactor trip when the Loop 4 SG level fell below the time delayed reactor trip setting. The root cause of the reactor trip was determined to be a failure to identify and perform adequate installation testing on a main steam dump valve controller following its relocation as part of the digital feedwater modification performed during the Unit 1 Cycle 17 refueling outage.	FWCS	Electronic
Sequoyah 2	3282007001	1/23/2007	The immediate cause of the event was closure of the Loop 2 main feedwater regulating valve as a result of a failed control air line. The closure of the feedwater regulating valve resulted in a reactor trip from low steam generator level. The feedwater regulating valve's control air line was damaged as a result of improper routing of field tubing during a recent outage modification. The routing of the control air line did not sufficiently account for movement of the valve due to thermal growth. During an attempt to place the bypass feedwater regulating valve in control in order to allow repair to the damaged control air line, the control air line to the main feedwater regulating valve broke. The main feedwater regulating valve failed closed as designed upon loss of control air.	FRV	Air

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Sequoyah 2	3282007002	3/13/2007	The immediate cause of the event was loss of process control to the 2A main feedwater pump resulting in a reduction in steam generator level and a subsequent manual reactor trip. The root cause of the event was a faulty local/remote switch which is internal to the 2A main feedwater pump speed indicating controller. This switch was found to be erratic and of poor quality.	FWPT	Electronic
Sequoyah 2	3282008001	11/3/2008	The immediate cause was the failure of a Loop 4 SG feedwater regulating valve controller. The K1 relay associated with the Unit 2 Loop 4 main feedwater regulating valve flow indicating controller has been determined as the most probable cause of this event. The relay failure is attributed to a failing contact connection, which resulted in a slow, closing drift of the main feedwater regulating valve.	FWCS	Electronic
South Texas 1	4982010003	8/20/2010	Root Cause No. 1 (Organizational) Procedure place keeping standards for the site were less than adequate. Root Cause No. 2 (Organizational) Supervisory Oversight of surveillance test procedure OPSP03-SP-0006R became ineffective when the SRO stepped outside of his oversight role and became involved in the process.	RPS	Error

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
St. Lucie 2	3892008003	6/7/2008	The event investigation determined that the 2B Condensate Pump "B" phase motor lead lugs overheated and melted due to high resistance at the lug crimp connections. The high resistance was caused by undetected epoxy resin in-the motor lead cables. The motor lead lugs were installed with undetected epoxy resin in the motor lead cables because a vendor inadvertently impregnated the motor lead cables with epoxy resin during the Vacuum Pressure Impregnation (VPI) process. The root cause for the undetected epoxy resin was the motor rewind specification did not have specific hold points to detect epoxy resin in motor leads.	Condensate	Motor
St. Lucie 2	3892011002	6/6/2011	A root cause determined the event was "human error vulnerability" resulting from a previous 1998 procedure change in the test methodology which required depressing the matrix relay hold pushbutton during the performance of the entire test, placing the circuit in a ready-to-actuate state.	RPS	Error
St. Lucie 2	3892012001	5/11/2012	A root cause determined the failure of FCV-9011 was a result of untimely corrective actions and sub-quality parts for the travel sensor (Xact) on the position feedback transducer provided by the vendor.	FRV	Air
Summer	3952008001	1/24/2008	The root cause was determined to be the failure of the feedwater flow control valve positioner pilot valve. The failure was due to either fretting as a result of normal operation or foreign material inclusion into the component's air system due to insufficient filtration and vibration induced component wear.	FRV	Air

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Susquehanna 1	3872010002	4/22/2010	Performance characteristics of the mechanical equipment associated with the RFP turbine steam admission system were not well understood. As a result, the ICS system gains were inadequate for the low power and steam flow conditions that existed at the time of the test. The root cause for both the April22, 2010 and May 14, 2010 Unit 1 scram events was due to less than adequate engineering rigor being applied during the development and implementation of the ICS gains/tuning factors as evidenced by: • Failure of the plant simulator to accurately model the ICS master feedwater level controller function; • Failure to use alternative methods (e.g., control system vendor simulator or other tools/models) to validate simulator changes prior to its use to predict actual plant performance; and • Failure to test the installed feedwater control systems with sufficient rigor (i.e., a less than adequate incremental approach to testing was employed).	FWCS	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Susquehanna 1	3872010002	5/14/2010	The ICS MFWLC was not originally configured with sufficient gain to handle a large transient such as the loss of a Condensate Pump. This conclusion is based on review of event data that showed that the MFWLC demand to the 'A', 'B' and 'C' RFP turbine speed controllers did not decrease sufficiently to terminate the reactor vessel level increase following the condensate pump trip. The root cause for both the April22, 2010 and May 14, 2010 Unit 1 scram events was due to less than adequate engineering rigor being applied during the development and implementation of the ICS gains/tuning factors as evidenced by: • Failure of the plant simulator to accurately model the ICS master feedwater level controller function; • Failure to use alternative methods (e.g., control system vendor simulator or other tools/models) to validate simulator changes prior to its use to predict actual plant performance; and • Failure to test the installed feedwater control systems with sufficient rigor (i.e., a less than adequate incremental approach to testing was employed).	FWCS	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Susquehanna 2	3882011003	8/19/2011	Direct Cause: • The incorrect termination of a single internal jumper in the ICS Level 8 trip circuit was the direct cause of the August 19, 2011, Unit 2 scram event. Three Root Causes were identified: • Conflicting and unclear procedure requirements and less than adequate reinforcement of management expectations for work package content resulted in a key visual check of internal jumpers being omitted from the scheme check work package during its preparation, and therefore testing failed to check and discover the miswired jumper. • Less than adequate procedure adherence during development of engineering change functional testing resulted in insufficient testing of the ICS Level 8 main turbine trip logic. • The PCWO (plant control work order) review process weaknesses related to procedure content, procedure adherence, reinforcement of expectations, and definition of PCWO work scope resulted in the review of the ICS Level 8 scheme check work package not identifying the missing key internal jumpers. This resulted in a missed opportunity to identify the incorrectly terminated conductor.	TPS	Error

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Turkey Point 4	2512010002	1/11/2010	The cause of the unit trip was an anticipated outcome of losing a SGFP at the exhibited operating power level. The root cause of the loss of the 4P1A SGFP lube oil level was determined to be unresponsive seal water injection controls to the pump outboard bearings which resulted in inadequate seal water injection flow to the 4P1A SGFP outboard seal coincident with SGFP bearing cavity drain blockage. It is worthy of note that the low oil event was a result of two conditions occurring at the same time and the loss of oil would have not occurred if only one of these conditions were present.	FWP	Pump
Turkey Point 4	2512010004	9/8/2010	The event was evaluated to determine the root cause and contributing causal factors. There were two root causes identified for the event: 1. Deficiencies in the work order package and guiding procedure failed to establish and/or verify the plant conditions required to successfully complete the evolution and relied on Operations staffing to provide the validation that the evolution could be performed. 2. The station failed to meet the standard of excellence expected for communication, accountability, ownership, formality, and rigor resulting in no one group having the full picture required to successfully complete the evolution.	RPS	Error
Turkey Point 4	2512010006	9/21/2010	The root cause of the event is excessive pin separation in ELCO connectors which is causing component failures due to inadequate installation instructions and inspection criteria. A contributing cause is that the modification implementation instruction contains no special installation instruction with respect to pin separation in ELCO connectors.	RPS	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Vogtle 1	4242011002	8/31/2011	A root cause team was formed to analyze this event. Troubleshooting directed by the root cause team determined that the pressure gauge associated with the air gag was indicating approximately 3 psig lower than the actual pressure applied. As a result, when the operators matched the indicated pressure from the air gag pressure gauge with the pressure gauge on the output of the positioner and aligned the three way valve to port air directly from the air gag regulator to the MFRV, the air pressure was approximately 3 psig higher than from the positioner. The increased air pressure to the MFRV actuator caused the valve to be further open than when it was controlled from the positioner. The root cause team determined that the abrupt increase in feedwater flow that was observed was consistent with the expected increase in valve travel with the 3 psig additional air pressure being applied. Since the increased feedwater flow through the MFRV was beyond the capability of the BFRV to control even with the BFRV fully closed, S/G 2 water level continued to rise until the Hi-Hi S/G level NTS was reached. This resulted in the reactor trip and subsequent AFW actuations.	FRV	Error
Vogtle 1	4242012002	4/14/2012	The apparent cause of the event was a failed "Position 5" circuit board judged to be due to component aging in the MFP turbine speed control circuit. A "Position 5" circuit board's function within the MFP controller is to process feedback signals from the pilot valve position, operating valve position and shaft speed. Its failure impacted the control signal provided to the MFP speed governor thus resulting in steam generator flow mismatches.	FWPT	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Wolf Creek	4822009001	4/28/2009	On April 28, 2009 at 3.27 p.m. Central Daylight Time (CDT), Wolf Creek Generating Station (WCGS) automatically shut down from operating at approximately 100 percent power because the "B" Main Feedwater Regulating Valve (MFRV), which provides water to the "B" steam generator (SG), failed to the closed position. Overheating of the fuses due to degraded fuse holders in the Westinghouse 7300 card frame caused the primary and secondary card frame fuses to fail, which disrupted the control power to the "B" MFRV. In response to a loss of control power, the "B" MFRV closed to its designed safe position. As the water level decreased in the "B" SG, the reactor tripped at the low-low SG water level set point of 23.5 percent. WCGS instituted less than adequate actions to address known deficiencies of the Littelfuse fuse holders. Procedures did not require routine inspections of the indicating lights for the 7300 card frame fuses, or specify acceptance criteria for the 7300 system card frame fuse holders. Thermography was being used, but there were no specific criteria for card frame fuse holders. Littelfuse fuse holder model number 342038A was used in an application for which it was not designed. Overheating of the Littelfuse fuse holders subjected the fuses to temperatures as high as 119.9 degrees Centigrade and was most likely caused by high resistance at the riveted connection and spade terminations. The maximum temperature rating of the fuses is 125 degrees Centigrade.	FWCS	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Wolf Creek	4822010005	3/2/2010	During the performance of procedure SYS PN-200, inverter PN09 did not transfer from the normal to alternate power supply due to the sticking of the reed relay on the static transfer switch circuit board.	FWCS	Electronic
Wolf Creek	4822010006	3/8/2010	The cause of the MFW pump tripping is a failed servo valve in the main feedwater speed control system. A Hardware Failure Analysis is investigating the exact cause for the servo failure. The servo valve is a device that takes an electrical signal and converts it to mechanical signal. The servo ports hydraulic oil to the bottom side of the pilot valve that controls the position of the secondary operating cylinder, which then controls the position of the low pressure (LP) and high pressure (HP) control valves for the feedwater turbine. The servo failed when it was in the open position, causing the pilot valve to travel full open, and the LP and HP control valves to become full open. This resulted in more steam being admitted to the feedwater turbine when there was no demand for it. The speed of the feedwater turbine increased beyond its overspeed set point, resulting in the trip of the MFW pump.	FWPT	Hyd

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS Table A-1					
Unit	LER	Event Date	Cause	System	Category
Wolf Creek	4822010012	10/17/2010	Control room operators were unable to maintain SG levels at low power using the main feed regulating bypass valves in automatic or manual control eventually over feeding the 'B' SG. As a result the turbine tripped on High-High SG level, which initiated a FWIS. The basis for the operators inability to control SG levels is provided below. Guidance in plant operational procedures was not aligned with the required plant design parameters -for low power operations, specifically in controlling feed water preheating, SG level control and response to a FWIS. As a result, the operation of the plant during power ascension was outside the main feedwater bypass valve optimum operating region and the feedwater preheating limitations. Main feedwater bypass valve characteristics and SG level process control settings did not provide stable (convergent) operating characteristics during low power operations. As a result, there was an over reliance on manual feedwater control and individual operator experience to mitigate SG level oscillations.	FWCS	Electronic

REACTOR TRIP EVENTS - CAUSES AND CATEGORIZATIONS

Table A-1

Unit	LER	Event Date	Cause	System	Category
Wolf Creek	4822011007	6/26/2011	The cause of the 'B' MFP trip was a failure of one or both of two controller cards in the main feedwater turbine control system. The controller cards are obsolete and no longer have vendor support. The equipment reliability program had targeted the controller cards for replacement. This original turbine control system is currently scheduled for replacement by a new MFP digital control system in Refueling Outage19 (Fall 2012).	FWPT	Electronic