Operating Experience Feedback Report – Reliability of Safety-Related Steam Turbine-Driven Standby Pumps

Commercial Power Reactors

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ABSTRACT

This report documents a detailed analysis of failure initiators, causes and design features for steam turbine assemblies (turbines with their related components, such as governors and valves) which are used as drivers for standby pumps in the auxiliary feedwater systems of U.S. commercial pressurized water reactor plants, and in the high pressure coolant injection and reactor core isolation cooling systems of U.S. commercial boiling water reactor plants. These standby pumps provide a redundant source of water to remove reactor core heat as specified in individual plant safety analysis reports.

The period of review for this report was from January 1974 through December 1992 for licensee event reports

(LERS) and January 1985 through December 1992 for Nuclear Plant Reliability Data System (NPRDS) failure data.

This study confirmed the continuing validity of conclusions of earlier studies by the U.S. Nuclear Regulatory Commission (NRC) and by the U.S. nuclear industry that the most significant factors in failures of turbine-driven standby pumps have been the failures of the turbine-drivers and their controls. Inadequate maintenance and the use of inappropriate vendor technical information were identified as significant factors which caused recurring failures.

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EXECUTIVE SUMMARY

This study reviewed operational failures of auxiliary feedwater (AFW), high pressure coolant injection (HPCI), and reactor core isolation cooling (RCIC) pump turbine assemblies installed in U.S. commercial pressurized water reactor (PWR) and boiling water reactor (BWR) power generating plants. The purpose of this study was to gather and review available data on failures of standby turbine-driven pumps (TDPs) to identify failure mechanisms and corrective actions for feedback to the NRC staff and to industry. The findings and conclusions documented in this report are based on the following: (1) a review of approximately 2000 Licensee Event Reports (LERs) for the period of 1974 through 1992, of 660 Nuclear Plant Reliability Data System (NPRDS) failure reports for 1985 through 1992, and of generic communications and studies issued by the U.S. Nuclear Regulatory Commission (NRC), and by the U.S. industry; (2) discussions with appropriate personnel at selected plants to gain a better insight into specific failures that had been reported; (3) discussions with the turbine and governor manufacturers to gain a better understanding of the components involved. Though NPRDS provided useful information to supplement LER failure data for these standby turbine-driven pumps, NPRDS was not designed to provide reliability and failure rate data required to perform a rigorous reliability analysis of the turbine drivers which have been a recurring problem in system reliability.

This study confirmed the continuing validity of earlier NRC and U.S. industry studies which have shown that the most significant factors in failures of standby TDPs have been the failures of the turbine drivers and their controls. An example is NUREG/CR-5404, the study of auxiliary feedwater system failures through 1986, which found that the standby turbine was a principal contributor to AFW system failures, and that the turbine governor and controls were the primary contributors to the AFW turbine failures. Recurring failures identified during this study were reviewed for root causes and failure initiators that had not been previously addressed in generic communications.

The study found that the demand probability for the AFW TDP was $6.5\text{E-}2$ excluding maintenance unavailability, compared with a value for the Surry Probabilistic Risk Assessment (PRA) in NUREG-1150 of $1.1\text{E-}2$ for AFW. Estimates of demand probability for PRAs usually both actual demands and surveillance testing, with the major contribution being from surveillance testing. Consequently, the demand probability in this study for the AFW TDP pump is higher than plant-specific values used in PRAs. Failures were caused primarily by turbine overspeed trips.

The study found a demand probability, excluding maintenance unavailability, of $1.9\text{E-}2$ for the HPCI TDP pump and a demand probability of $1.3\text{E-}2$ for RCIC TDP. Demand probability for HPCI and RCIC in NUREG-1150 for Peach Bottom was $3.0\text{E-}2$. Failures were due to a turbine overspeed trip and a failed flow controller.

During the past 16 years, though there have been 71 NRC and industry generic communications and studies which addressed problems with these standby turbines, there have been recurring problems with the reliability of these turbine assemblies. Twenty-two of these documents were issued in the past 6 years. Institute of Nuclear Power Operations seminars in February 1981 addressed problems of inadequate standby TDP reliability for both PWR and BWR plants. Recurring turbine failures still have as their apparent cause the failure to perform preventive maintenance identified at the INPO seminars, and in manufacturers' guidance. A February 1990 Nuclear Management and Resources Council letter to the NRC Executive Director for Operations (Ref. 5) identified these standby turbines on a list of problem components.

Most HPCI, RCIC and AFW TDPs have as their drivers Terry steam turbines designed to reach their required speeds of from 3550 to 5900 revolutions per minute in from 60 to approximately 120 seconds from the cold shut-down condition to meet the reactor safety analyses of the Nuclear Steam Supply System vendors. This is called a "cold quick-start." The physical location of AFW turbines varies among plants, resulting in different ambient temperature and humidity ranges with varying environmental effects on turbine deterioration and operational performance. Leaking steam inlet valves worsen the situation by allowing condensate contamination of the turbine lubricating oil (frequently used as the hydraulic fluid for the governor and actuator, for which a primary failure cause is water-contaminated oil). These conditions can cause accelerated deterioration of turbines and governors in a standby mode, resulting in failures that are not identifiable until startup. Certain turbine governor failures were caused by the removal of governor modifications because of inadequate design control.

Surveillance test requirements have allowed a range of approaches, some of which may not replicate actual demands. Over time, more plants appear to use cold quick-starts for surveillance testing as a result of industry and regulatory feedback. Turbine failures during cold quick-start transients appear to primarily result from failures of governor control and from the coordination of governor valves with turbine steam inlet valve opening, as well as condensate in turbine steam supply lines. There are a significant number of cases of turbine trips during initial startup for which failure reports stated that the cause was unknown. This study indicates that such failures

may be linked to governor response, which is affected by design and maintenance practices. Pump reliability during cold quick-starts can be affected by such factors as ambient temperatures, as well as by water and other oil contaminants.

A significant factor affecting standby turbine reliability identified during this study was maintenance which did not incorporate existing manufacturers' guidance, including specified periodicities. Maintenance-related failures identified in LERs and NPRDS failure reports during this study included: (1) operational failures of turbine and governor sub-components and piece-parts presently identified by the turbine manufacturer for preventive maintenance, for which this maintenance did not appear to be performed completely with specified periodicities prior to

the reported failure; (2) failures of subcomponents and piece-parts as a result of site-specific aging phenomena not considered in preventive maintenance programs.

The rate of failure of these standby pump turbine-drivers continued to remain essentially constant, and review of operational experience indicated that many of these failures were repetitive. Enhancement of standby turbine reliability by elimination of the cause of these failures appears to be achievable by better industry-wide implementation of existing requirements and guidance for design, maintenance and operation of these turbine assemblies. The continuing reports of recurring failures, such as electric governor dropping resistors and overspeed trip ball tappets, are strong indications that additional effort is warranted.

1 INTRODUCTION

This study, which expands on special study AEOD/S93-01, "Review of Auxiliary Feedwater Reliability,"¹ (Ref. 1) was initiated because of recurring operational failures of auxiliary feedwater (AFW) pump turbine assemblies (turbines with their related components, such as governors and valves) that are installed in U.S. commercial pressurized water reactor (PWR) power generating plants. The purpose of this study was to gather and review failure data for standby turbine-driven pumps to identify failure mechanisms and corrective actions and for feedback to the NRC staff and to industry.

Standby turbine-driven AFW pumps (TDAFWPs) are used as a means of removing reactor core heat by providing a diverse and redundant source of AFW in response to specified off-normal and accident conditions, including functioning as a stand-alone pump during specified events, such as a station blackout. Because of their failures and out-of-service history, TDAFWPs have been identified as a significant contributor to core damage frequency (CDF) in individual plant probabilistic risk assessments (PRAs).²

Because of the similarities of application, design and operation of standby turbine-driven pumps used in boiling water reactors (BWRs), as well as the identity of certain turbine failures, this study includes failures of these pumps, which are used in the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems to provide redundant sources of reactor-grade water for the removal of core heat under specified off-normal and accident conditions when the main feedwater system is not available.

Most safety-related AFW, HPCI and RCIC standby turbines have been supplied by the Terry Corporation, which became the Terry Turbine Division of Ingersoll-Rand, and is now DRESSER-RAND, Terry-Turbodyne, a joint venture. This company typically will be identified as "Terry" in this report. Certain AFW and RCIC turbines are basically the same design. Except for certain reliability data which include all turbines for consistency with previous analyses, this report addresses only turbines supplied by the Terry Corporation or its successors.³ Figure 1 is an illustration of a Terry turbine with its upper housing removed.

2 BACKGROUND

Seventy-one NRC and industry generic operational feedback documents, including 10 studies and 11 General

¹(Ref. 1) includes failure data through 1992 and supports the findings of this study.

²An example is NUREG/CR-4550, "Analysis of Core Damage Frequency: Surry, Unit 1", Volume 3, Part 1 (Ref. 2).

³Demand start failure data includes failures for all standby turbines to permit meaningful comparison with previous studies.

Electric (GE) Nuclear SILs, have been issued since Figure 1

1976, addressing recurring problems with AFW, HPCI, and RCIC standby pump turbine-drivers. Twenty-two of these documents were issued in the past 6 years. Institute of Nuclear Power Operations (INPO) and NRC generic communications issued through 1993 are shown in Tables 1 and 2. A historical overview of AFW system failures through 1986 published in NUREG/CR-5404, Volume 1, "Auxiliary Feedwater System Aging Study," (Ref. 3) showed that the standby TDAFWP was a principal contributor to AFW system failures, and that the turbine governor and controls were the principal contributors to TDAFWP failures. The present study has extended the data review to include more recent failures, and has resulted in an integrated and comprehensive compilation of the failure initiators or root causes of reported failures, as well as maintenance actions developed by the industry that should prove effective if implemented. The majority of standby turbine failures were the result of malfunctions of the turbine governor during cold quick-starts (which are discussed in Section 2.1). As identified in NRC Information Notice (IN) 88-67 (Ref. 4), the turbine overspeed trip device tappets were a contributor to turbine unreliability (which is addressed in Section 2.3).

2.1 Standby Turbine Cold Quick-Starts

"Turbine cold quick-starts" are required to meet pump starting time limits in plant Updated Safety Analysis Reports (USARs) for AFW, RCIC, and HPCI Engineered Safety Features (ESF) actuations, and other specified actuations to meet the reactor safety analysis requirements of the nuclear steam supply system (NSSS) vendors. A cold start typically has been considered to be a start that occurs when a turbine has not been operated for at least 72 hours. Turbine "quick-starts" occur when the turbines are required to reach rated speed and pump flow [speeds of from 3550 to 5900 revolutions per minute (rpm)] in from 30 to 120 seconds.

NSSS vendors were contacted to verify that cold quick-starts of these safety-related standby turbine-driven pumps were required to meet the requirements of their plant safety analyses. One NSSS vendor indicated that their generic safety analysis could be revised to extend the time to 120 seconds (which must include all worst-case variables). Though the times varied slightly, essentially all pumps were required to cold quick-start to meet certain NSSS vendor plant safety analyses, and the selected turbine assemblies were considered to be capable of performing such starts.

Figure 1 Terry Turbine with its Cover Removed

*Courtesy of the
Dresser-Rand Company*

Table 1
NRC Information Notices and an NRC Circular Concerning Standby Turbines

NRC Circular 78-02:	Proper Lubricating Oil for Terry Turbines
Information Notice 80-29: (Supplement No. 1)	Terry Turbine Steam Inlet Flange Broken Studs
Information Notice 81-24:	Auxiliary Feed Pump Turbine Bearing Failures
Information Notice 81-36:	Replacement Diaphragms for Robertshaw Valves
Information Notice 84-66:	Turbine-Driven Auxiliary Feedwater Pump Undetected Unavailability
Information Notice 85-76:	Recent Water Hammer Events
Information Notice 86-14:	PWR Auxiliary Feedwater Pump Turbine Control Problems
Information Notice 86-14:	Overspeed Trips of AFW, HPCI, and RCIC Turbines (Supplement 1)
Information Notice 86-14:	Overspeed Trips of AFW, HPCI, AND RCIC Turbines (Supplement 2)
Information Notice 88-09:	Instability of Woodward PG-PL Type Governors
Information Notice 88-67:	PWR Auxiliary Feedwater Pump Turbine Overspeed Trip Failure
Information Notice 89-14:	Inadequate Dedication Process for Commercial Grade Components Which Could Lead to Common Mode Failure of a Safety System
Information Notice 89-58:	Turbine-Driven Auxiliary Feedwater Pump Disablement from Closure of One Parallel Steam Supply Valve
Information Notice 90-45:	Auxiliary Feedwater Pump Turbine Overspeed and System Over-Pressurization
Information Notice 90-51:	EGM Governor Voltage Dropping Resistor Failures
Information Notice 90-51: (Supplement 1)	EGM Governor Voltage Dropping Resistor Failures
Information Notice 90-76:	Failure of Turbine Overspeed Trip Mechanism Because of Inadequate Spring Tension
Information Notice 93-51:	Repetitive Overspeed Tripping of Turbine-Driven Auxiliary Feedwater Pumps

TABLE 2

INPO (LIMITED DISTRIBUTION) GENERIC COMMUNICATIONS ON TURBINE-DRIVEN STANDBY PUMP PROBLEMS. INPO DOCUMENT TYPES LISTED ARE AS FOLLOWS: SIGNIFICANT BY OTHERS REPORT (SOR); SIGNIFICANT OPERATING EXPERIENCE REPORT (SOER); SIGNIFICANT EXPERIENCE REPORT (SER), SIGNIFICANT EVENT NOTICE (SEN), AND OPERATING & MAINTENANCE REPORT (O&MR).

SEN-55	FAILURE OF A WOODWARD GOVERNOR RESULTING IN AFW PUMP TURBINE OVERSPEED
SOR 91-1	ITEM 6 ADDRESSING OVERSPEED FROM CONDENSATE IN THE TURBINE STEAM SUPPLY LINE
SOER 89-01	TESTING OF TURBINE/PUMP OVERSPEED TRIP DEVICES
SOER 86-01	RELIABILITY OF PWR AFW SYSTEMS
SOER 82-08	AFW TRIP & THROTTLE VALVE POSITION & INDICATION
SOER 82-14	RELIABILITY OF HIGH PRESSURE CORE COOLING SYSTEMS
SOER 81-13	CONCURRENT LOSS OF HIGH PRESSURE CORE COOLING SYSTEMS
SER 7-90	TURBINE OVERSPEED DUE TO GOVERNOR OIL CONTAMINATION
SER 3-90	INADEQUATE AFW SYSTEM TESTING AND PREVENTIVE MAINTENANCE
SER 26-87	HIGH PRESSURE COOLANT INJECTION [HPCI] TURBINE INOPERABILITY
SER 56-84	DISABLING SAFETY SYSTEMS BY MISPOSITIONING VALVES AND CONTROLS.
SER 18-83	TERRY TURBINE CONTROL VALVE FAILURE.
SER 36-83	LOSS OF ALL FEEDWATER
SER 53-83	FAILURE OF HPCI EGR ACTUATOR FROM STANDBY TURBINE OIL ADDITIVES.
SER 64-82	CONCURRENT FAILURE OF HPCI AND RCIC.
SER 34-81	BWR HPCI/RCIC MALFUNCTIONS
SER 72-81	EMERGENCY FEEDWATER [TDAFW] PUMP OVERSPEED
SER 77-81	COMPLETE LOSS OF AUXILIARY FEEDWATER
SER 18-80	AFW TURBINE. TRIPS OF A GIMPEL TRIP & THROTTLE VALVE.
SER 20-80	AFW TURBINE. TRIP AND THROTTLE VALVE TRIPPED AND COULD NOT BE RESET.
SER 23-80	AFW TURBINE TRIPPED ON AUTO START BECAUSE OF CONDENSATE IN THE STEAM LINE.
SER 32-80	LER 50-254/80-006. DELETION OF THE USE OF RCIC/HPCI STEAM SUPPLY VALVES TO INITIATE TURBINE START BECAUSE OF CONDENSATE IN THE STEAM SUPPLY LINES.

TABLE 2 (CONTINUED)

INPO (LIMITED DISTRIBUTION) GENERIC COMMUNICATIONS ON TURBINE-DRIVEN STANDBY PUMP PROBLEMS. INPO DOCUMENT TYPES LISTED ARE AS FOLLOWS: SIGNIFICANT BY OTHERS REPORT (SOR); SIGNIFICANT OPERATING EXPERIENCE REPORT (SOER); SIGNIFICANT EXPERIENCE REPORT (SER), SIGNIFICANT EVENT NOTICE (SEN), AND OPERATING & MAINTENANCE REPORT (O&MR).

SER 62-80	SIMULTANEOUS FAILURE OF HPCI AND RCIC.
O&MR 353	INOPERABLE HPCI TURBINES FROM MISPOSITIONED OIL SYSTEM VALVES.
O&MR 24	EFFECT OF TURBINE RESTARTING OF GOVERNOR
O&MR 061	AFW, RCIC, & HPCI TURBINE MAINTENANCE & INSPECTION ENHANCEMENTS.
O&MR 069	POST-MAINTENANCE AFW TURBINE VALVE THROTTLE SETTING AS A POTENTIAL FAILURE MECHANISM.
O&MR 199	TURBINE START FAILURE FROM STEAM INLET VALVE ADJUSTMENT.
O&MR 255	FAILURE OF HPCI TURBINE T&T VALVE TRIP PILOT SOLENOID VALVE DIAPHRAGM.
O&MR 303	AUXILIARY TURBINE STARTUP TRANSIENT IMPROVEMENT
SER 27-81	ADDRESSED THE LARGE NUMBER OF HPCI AND RCIC MALFUNCTIONS
O&MR 050	POSITIVE INDICATION OF AFW TURBINE OVERSPEED TRIP
O&MR 316	DEFECTIVE AFW PUMP TURBINE EMERGENCY HEAD LEVER DRIVES.

2.2 Standby Turbine Governors

AFW, HPCI and RCIC standby turbines supplied by Terry use speed control governors manufactured by the Woodward Governor Company (Woodward). These governors are discussed in Section 4.2 of this report. Their design features and certain failure initiators are described in Appendix A. Failures of these governors affecting standby turbine reliability are addressed in Sections 7.4.1, 7.5, 7.6, and 7.7, and in Appendix A.

2.3 Overspeed Trip Mechanism Ball-Type Tappets

Though there are several designs of Terry turbine mechanical overspeed trip mechanisms, only failures of ball-type tappets were identified in reviews of operational experience data. Maintenance instructions for Terry turbine overspeed trip mechanisms have specified for over 13 years that the trip ball-tappet (original design) be inspected for damage and deterioration after each test (or demand actuation). Such a requirement implies that each trip could damage the ball used in this original design. Based on recurring failures, certain plants could still have the original design, or the first redesign, of ball-tappets installed. The Electric Power Research Institute (EPRI) Maintenance Guide, NP-6909, "Terry Turbine Controls," states that the original design of ball-tappets should be replaced with the latest design (second redesign) at the next outage. This guide contains useful data that was not otherwise generally or readily available. The guide covers the controls used to operate Terry turbines and contains recommended periodic maintenance.

Operating experience data indicate that AFW, HPCI and RCIC standby turbines are still experiencing recurring failures of overspeed trip mechanism ball-type tappets. Figure 2 is a drawing of a Terry turbine overspeed trip system with a ball-tappet [Item 029 on the drawing]. As discussed in the EPRI Maintenance Guide NP-9609, an enhanced tappet design to replace the balltappets was offered by Terry. A second enhanced tappet design was identified in a Terry letter, "Overspeed Trip Tappets for Terry Steam Turbine Pump Drivers in HPCI, RCIC, and AFW Systems,"⁴ issued June 5, 1990. This latest tappet assembly redesign eliminates the tappet ball and compensates for the deleterious effects of high temperature and humidity which had prevented resetting the trip mechanism.

2.4 NRC and Industry Initiatives

Continuing repetitive failures of these turbine assemblies have been documented during the past 16 years in 17 NRC

⁴This information was covered in General Electric Company, San Jose, California, Service Information Letter (SIL) 392, Revision 1, dated November 28, 1990; and SIL 525, Revision 0, for HPCI and RCIC turbines, dated November 27, 1990, respectively.

INs and a circular, as well as in industry generic correspondence and studies. A Nuclear Management and Resources Council (NUMARC) letter to the Executive Director for Operations (EDO) of the NRC, dated February 16, 1990, (Ref. 5) containing the industry's current "Key Equipment Problems List," included "Turbine-driven Standby Pumps" on this list. The recurring failures of these safety-related turbine-driven pumps have generated a nearly continuous stream of operational feedback.

Since 1980, INPO has issued a report and forty-one other generic documents addressing the failures of these turbines and their controls. NRC, INPO, and industry generic communications regarding problems with the turbine-drivers for standby pumps primarily identified failure modes and initiators which appear to have resulted from not implementing existing manufacturers' maintenance instructions, and from marginal system design and quality program implementation (including procurement and dedication of commercial grade items).

In February 1981, INPO sponsored workshops which addressed recurring failures of the AFW, HPCI and RCIC standby-pump Terry turbines and Woodward governors. The stated objective of these workshops was to provide "hands on" experience, as well as to provide direction and guidance from the Woodward Governor Company, the Terry Corporation, and the Limitorque Corporation for reducing the types and number of failures. During the workshop for RCIC and HPCI turbines and controls, it was stated that the severe environmental conditions associated with these turbines necessitated maintenance, and that many Licensee Event Reports (LERs) for RCIC and HPCI failures indicated the lack of adequate maintenance. It was also stated that LERs indicated that only 40 percent of the then-operating BWR plants met a goal of 96 percent system success in response to a demand signal for operation of these turbines.

Design changes for the RCIC and HPCI turbines were proposed during these workshops. These design changes were intended to reduce turbine overspeed trips that occur during quick-start transients. Based on their commonality of design and application, certain proposed design changes for RCIC and HPCI are also appropriate for AFW turbines which use the same Woodward type EG-M governors that are used with HPCI and RCIC turbines. The scope of the present study did not include the determination of those plants which had incorporated those design changes, nor the effect of such design changes on subsequent turbine failures. Plant-specific differences in the implementation of these design changes and proposed GE modifications for HPCI and RCIC turbines could be a significant factor for differences in reported failures of these standby turbines at various plants.

In October 1985, EPRI issued Report NP 4264, "Failures Related to Surveillance Testing of Standby Equipment, Volume 1 Emergency Pumps," dealing with these pump turbine-drivers and their governors. This study reported that AFW systems with turbine-driven pumps accounted for approximately 69 percent of the AFW system LERs and identified failures related to the turbine governor control system and valves. The study further stated that the most troubled standby pump was the TDAFWP, and that the HPCI and RCIC systems had similar statistics. EPRI has issued two reports, NSAC-140, "Reliability of BWR High-Pressure Core Cooling 1978-1986," in January 1990, and NSAC-150, "Operating Experience of PWR Auxiliary Feedwater Systems 1979-1988," in June 1990, whose findings are similar to those contained in this report.

Since 1976, GE has issued 11 Service Information Letters (SILs) on HPCI and RCIC turbines. These SILs address design and operational changes, such as eliminating turbine overspeed trips by enhancing HPCI and RCIC turbine governor response to overspeed transients during cold quick-starts. No analogous effort was identified for AFW standby pump turbines.⁵

Since 1978, the NRC has issued 18 generic communications on the failures of these turbines and their controls, 8 of which were issued in the past 6 years.

In March 1990, Oak Ridge National Laboratory (ORNL) published NUREG/CR-5404, "Auxiliary Feedwater System Aging Study" (Ref. 3). The ORNL study stated that historically the AFW standby pump turbine-driver has been the primary source of AFW system degradation, with the governor instrumentation and controls accounting for approximately 69 percent of turbine-related demand failures.

3 APPROACH AND SCOPE

The operational failure history of these standby turbine-driven pumps was reviewed through two primary data sources: (1) LERs, and (2) Nuclear Plant Reliability Data System (NPRDS) component failure reports.

For the period from January 1985 through December 1992, 660 NPRDS-reported failures of safety-related standby turbines and their associated governors and governor valves, HPCI and RCIC and turbine steam inlet isolation stop valves, and valve operators were reviewed. Based on the results of an initial review of NPRDS failure data, the associated pumps, as distinct from the turbine-drivers, evidenced infrequent failures and were not included in the scope of this study. Though NPRDS pro-

vided useful information to supplement LER failure data for these standby turbine-driven pumps, NPRDS was not designed to provide reliability and failure rate data required to perform a rigorous reliability analysis of the turbine drivers which have been a recurring problem in system reliability, especially on a plant-specific basis.

Approximately 2000 LER abstracts obtained from the Sequence Coding and Search System (SCSS) and the NRC's Nuclear Document System Advanced Design (NUDOCS/AD) documenting 838 reportable events involving AFW [including emergency feedwater (EFW)], HPCI, and RCIC pump turbine-drivers covering the period from 1974 through 1992 were also reviewed. When abstracts were not definitive, the complete LER was retrieved and reviewed. To estimate the frequency of actual demands on standby pump turbine-driver assemblies, 934 LERs were reviewed which reported PWR reactor trips and ESF actuations, and 423 such LERs were also reviewed for BWR plants that covered the period from January 1987 through December 1992. When additional details were needed, NRC Office of Nuclear Reactor Regulation project managers and resident inspectors were contacted.

Over 60 NRC and industry generic communications and studies addressing these standby pump turbine-drivers were reviewed. Plant USARs, recent individual licensee plant annual reports to the NRC, and NRC inspection reports were also reviewed for information pertinent to standby pump turbine-driver reliability.

Appropriate personnel were contacted at selected plants to gain a better insight into the details of specific failures that had been reported. DRESSER-RAND Terry-Turbodyne (Terry), and Woodward, the manufacturers of the standby turbines and their governors, respectively, were also contacted to gain a better understanding of the components provided by each company, and to discuss failure initiators involving the design, installation, modification, maintenance, and operation of these components.⁶

Recurring failures identified during this study were analyzed for root causes and failure initiators that had not been previously addressed in generic communications.

4 FACTORS AFFECTING STANDBY TURBINE RELIABILITY

The design of TDAFWP turbines and their governor systems was within the scope of the Architect-Engineer (AE) for each PWR plant. These designs are plant-specific and vary significantly. The BWR NSSS vendor (GE) was responsible for the design of the HPCI and RCIC turbines,

⁵A Terry Turbine Users Group was begun in April 1993 in conjunction with the EPRI Nuclear Maintenance Application Center (NMAC).

⁶The use of such terms as "Terry-Turbodyne stated..." or "Woodward stated..." are used to indicate information provided by the manufacturer's staff and not an official company position.

governor systems and governor valves. Table 3 compares the design feature of AFW, HPCI and RCIC turbines which affect turbine operational characteristics. Included are features which provide a capability to prevent over-speed during cold quick-starts.

AFW, HPCI and RCIC turbines were designed for varying ranges of inlet steam pressure as discussed in Section 4.1, which require governor valve response to control turbine speed. Terry stated that governor valves are sized based on the required steam flow at the minimum specified design turbine steam inlet pressure, and that there are curves showing required governor valve percent-open versus steam pressure. The rate of turbine speed increase is conditioned by turbine design speed and inlet steam pressure at the time of turbine quick-start, as well as the design speed. Turbines vary in their design characteristics, as discussed below.

4.1 Turbine-Driven Standby Pump Design Factors

The following sections identify standby turbine assembly design factors that affect turbine performance and reliability.

4.1.1 Turbine Design Factors

Based on data provided by DRESSER-RAND Terry-Turbodyne (Terry), the operational characteristics (power rating, maximum and minimum steam inlet pressures and turbine/pump speed) of AFW pump standby turbines vary widely from plant to plant. These plant-specific differences could affect a specific turbine's tendency to over-speed during cold quick-starts. For AFW pump turbines, horsepower ratings vary from 276 to 1590, and operating speeds range from 3550 to 5900 rpm. Maximum AFW pump turbine inlet steam pressures range from 9195.5 kilopascals (kPa) (1333.7 pounds per square inch absolute (lbf/in²)) to 790.7 Kpa (114.7 lbf/in²). Certain AFW turbines having maximum inlet design steam pressures of 4237.7 Kpa (614.7 lbf/in²) and lower have pressure regulating or reducing devices upstream of the turbine. HPCI pump turbine designs have horsepower ratings of 2600-5100, with speeds of 3900-4200 rpm, and turbine maximum inlet steam pressures of 8029.4 Kpa (1164.7 lbf/in²). RCIC pump turbine horsepower ratings vary from 460 to 875, with speeds from 4500-4600 rpm, and maximum turbine steam inlet pressures of 8029.4 kPa (1164.7 lbf/in²).

4.1.2 Turbine Lubrication System Factors

Certain AFW pump turbines are lubricated by "oil slinger rings," and do not have the shaft-driven lube oil pumps and pressurized lube oil systems that are used with HPCI, RCIC, and other AFW turbines. Pressurized lube oil sys-

tems provide oil pressure to turbine bearings and to the governor assembly as soon as the turbine begins to roll, enhancing both turbine lubrication and governor response. Pressurized lube oil systems permit the use of oil filters to maintain oil quality. HPCI turbines additionally have a motor-driven auxiliary oil pump (AOP) which automatically starts at the initiation of turbine start (prior to turbine roll). AOPs rapidly pre-lubricate the turbine bearings, as well as provide hydraulic oil pressure to operate the turbine governor system, including the EGR governor actuator, and the governor valve to prevent turbine over-speed during cold quick-starts.

Since standby turbines are idle for extended periods of time, lubricating oil drains from the turbine bearings, leaving the bearings vulnerable to excessive wear. Without a pressurized lube oil system to provide relatively rapid lubrication during cold quick-starts, the bearings of certain AFW turbines could experience increased bearing wear resulting from such starts. It was noted during this study that one PWR plant had both AC and DC lube oil pumps for its TDAFWP turbine.

4.2 Turbine Governor Factors

All Terry turbines that drive AFW, HPCI, and RCIC pumps use Woodward governors for speed control, including the prevention of overspeed during cold quick-starts. Woodward stated that there are many variations of basic governor types, which provide different speed control characteristics. Governor types, such as EG and PG, are families of governors built having a basic speed control design.

A review of NPRDS engineering data identified the following six types of Woodward governors which are installed on Terry turbines used as drivers for AFW system safety-related standby pumps: PG-PL, EG-M, PGA, PGD, PGG, and UG⁷. Type EG-M governors (with EGR actuators) are used with all HPCI and RCIC turbines, and with certain TDAFWPs. A discussion of these six types of governors, as well as the EGR actuators used with EG-M governors, as well as governor problems and their causes and correction, is provided in Appendix A.

Woodward governors can be purchased either direct acting (which fail to the low speed stop) or reverse acting (which fail to the high speed stop, or cause an overspeed trip). Both direct acting and reverse acting governors are used with these Terry turbines. Governors can operate in the clockwise, or counter-clockwise direction, or in both directions, depending upon the arrangement of the integral check valves for the governor/actuator hydraulic oil pump.

⁷NPRDS engineering records for certain plants neither identified the governor type, nor contained a designation that could be identified by Woodward Company personnel.

TABLE 3

DESIGN CHARACTERISTICS OF STANDBY PUMP TERRY TURBINE-DRIVER ASSEMBLIES ¹			
CHARACTERISTICS	HPCI	RCIC	AFW
INSTALLED WOODWARD ELECTRIC GOVERNORS FAIL (ON LOSS OF POWER) TO TURBINE SHUTDOWN (RCIC) OR OVERSPEED TRIP (HPCI)	YES	YES	SOME ²
AUTOMATIC RESET OF TURBINE TRIPS TO PERMIT REMOTE RESTART OF THE TURBINE	YES	MANY	NO ³
TURBINES AUTO-START WHEN A TRIP IS AUTOMATICALLY RESET AND AN AUTO-START SIGNAL IS PRESENT	YES	MANY	NO
THE TERRY SUPPLIED GOVERNOR VALVES ARE SPRING-LOADED TO CLOSE WHEN THE TURBINE IS IDLE TO REDUCE TURBINE OVERSPEEDING DURING A QUICK-START	YES	NO	NO ⁴
THE TERRY SUPPLIED GOVERNOR VALVES OPEN TO THE MAXIMUM POSITION AS A TURBINE IS SHUT DOWN (IN RESPONSE TO REDUCED STEAM PRESSURE) AND ARE FULLY OPEN AT THE INITIATION OF A QUICK-START	NO	YES	YES ⁵
HYDRAULICALLY-OPERATED BALANCE-CHAMBER TURBINE STEAM-INLET ISOLATION STOP VALVES ARE PROVIDED BY TERRY TO COORDINATE TURBINE INLET AND GOVERNOR VALVE RESPONSES (LIMIT TURBINE OVERSPEED) DURING QUICK-STARTS	YES	NO	NO
TERRY SUPPLIED MOTOR-OPERATED BALANCE-CHAMBER DESIGN TURBINE STEAM-INLET ISOLATION STOP VALVES TO ENHANCE COORDINATION OF VALVE RESPONSES DURING QUICK-STARTS	NO	YES	SOME ⁶
THE TERRY SUPPLIED TRIP VALVES ARE OPEN EXCEPT WHEN TRIPPED	YES	YES	SOME ⁷
TERRY SUPPLIED MOTOR OPERATED AUXILIARY LUBE OIL PUMP (AOP) PRE-LUBRICATES THE TURBINE-DRIVER AT QUICK-START, AND PROVIDES RAPID OIL PRESSURE TO THE TURBINE GOVERNOR FOR RAPID GOVERNOR VALVE RESPONSE FOR QUICK-STARTS	YES	NO	NO ⁸
THE TERRY SUPPLIED TURBINE SHAFT-DRIVEN LUBE OIL PUMP PROVIDES POSITIVE LUBRICATION, AS WELL AS PERMITS THE USE OF A LUBE OIL FILTER TO KEEP TURBINE OIL AND GOVERNOR OIL CLEAN	YES	YES	SOME ⁹
TURBINES USE WOODWARD EG-M ELECTRIC GOVERNOR SYSTEMS AND BGR ELECTRIC-HYDRAULIC-MECHANICAL GOVERNOR VALVE ACTUATORS, WHICH HAVE A RAMP GENERATOR TO CONTROL THE RATE OF TURBINE SPEED INCREASE DURING QUICK-STARTS TO PREVENT OVERSPEED TRIPS	YES	YES	SOME ⁹

¹ This table does not address design changes implemented by GE SILs for HPCI and RCIC turbines which may be installed at certain sites, or other site-specific design changes and modifications, such as custom buffer springs installed to correct turbine speed instabilities and overspeeding. The GE SILs define modifications that enhance standby turbine reliability.

² The type of governor (reverse acting which fails to a turbine's high speed stop or overspeed trip; or direct acting which fails to the low speed stop) is a level of detail not identified in USARs.

³ This study did not identify a plant which had an automatic reset of AFW pump trips.

⁴ Discussed with Terry-Turbodyne. This level of detail is not covered in USARs.

⁵ When ordered from Terry, TDAFWP assemblies were supplied with these valves. At certain plants, valves not supplied by Terry appear to be used. At other plants, the AE used the Terry supplied trip (and throttle) valve as the turbine steam isolation valve.

⁶ Certain AFW turbine installations use the trip and throttle valve as the turbine steam isolation stop valve.

⁷ Certain AFW turbines have shaft-driven lube oil pumps, with and without oil filters. Other AFW turbines are lubricated only by slinger rings and have no lube oil filter. Other installations do not use turbine oil to supply governor oil.

⁸ Certain AFW turbines have used all of the types of Woodward governors discussed in section 4.2 and Appendix A, and some AFW turbines use governors which could not be identified from the NPRDS engineering database.

Woodward indicated that their instructions to end-users provide calibration, maintenance, and troubleshooting procedures, and include caution statements that should be used for all their governor systems and components. They advised that end-users should not develop their own (different) procedures. If additional instructions are required, Woodward should be contacted. A specific exception is GE Service Information Letter (SIL) 351, Revision 2, dated April 4, 1990, which was coordinated with both Woodward and Terry. Woodward stated that necessary end-user procedures are shipped to original equipment manufacturers (OEMs) in the container with each governor, and similarly are shipped to end-users with a replacement governor.

Non-nuclear applications for these turbine governors typically involve continuous operation, with a turbine startup that is relatively gradual and preceded by warm-up of the steam lines and the turbine. This type of warm-up minimizes transients and wear. In contrast, safety-related standby turbine-driven pumps are normally in a cold shutdown condition, typically in areas of high humidity, with temperatures that vary over a wide range. Leaking turbine inlet steam supply isolation stop valves worsen the situation by maintaining a saturated steam environment in the turbine, contaminating the turbine lubricating oil with condensate. Turbine lubricating oil is used in certain installations as the hydraulic fluid for the Woodward turbine governors and actuators. A significant historical cause of governor failure identified by Woodward since before 1981 has been water (including steam condensate) contamination of governor and EGR actuator hydraulic fluid. Standby conditions can lead to deterioration of the turbine and governor, which is caused by water contamination in the oil, that may not be noticed until turbine startup. Turbine oil additives (such as vapor phase inhibitors) used to reduce the effects of standby service have caused failures of non-metallic parts (see NRC Office of Inspection and Enforcement IN 81-36 [Ref. 6]).

Reliable operation of Terry governor valves to meet design demands and prevent overspeed trips during cold quick-starts is dependent upon governor operation, including a rapid buildup of hydraulic pressure in the governor system. For most standby turbines, the rate of governor speed change during turbine startup is controlled by a ramp generator circuit for electric governors, and by a ramp bushing for mechanical-hydraulic governors.

Type PGD mechanical-hydraulic governors and some earlier type EG-M electrical governor systems were not provided with speed increase ramp features to reduce overspeed during quick-starts. This fact could contribute to increased standby turbine overspeed trips during cold quick-starts with these governors.

Standby turbines supplied by Terry typically use turbine lubricating oil as the hydraulic operating fluid for their

governors and actuators. Terry turbine lube oil is an International Standards Organization (ISO) Viscosity number 32 (Society of Automotive Engineers [SAE] 30) or 10W-30⁸ weight oil, with possible additives for turbine service, and with vapor inhibitor (VI) additives to prevent turbine rusting during standby service. Oils of other types and grades are permitted for governor use within certain bounding viscosity limits that are defined in Woodward technical literature, which shows that the maximum oil viscosity (minimum fluidity) for reliable governor and actuator response during Terry turbine quick-starts is 300 Saybolt Seconds Universal (SSU). A standby turbine could trip on a cold quick-start because of viscous oil, but would not trip on subsequent starts after the oil had circulated and become more fluid, resulting in the initial overspeed being declared spurious or unknown.

According to Woodward manual 25071, "Oils for Hydraulic Controls," dated 1986, Table 4-1, "Viscosity and Operating Temperature of Oils", an ISO-Viscosity number 32 (SAE 30) weight oil would have a viscosity of 300 SSU at approximately 112 degrees Celsius (130 degrees Fahrenheit), while an SAE 10W-30 oil would have a viscosity of 300 SSU at about 37 degrees Celsius (98 degrees Fahrenheit). Woodward manual 36641F, "Governor Oil Heat Exchanger Remote and Integral Types," dated 1971, states that governor oil should not be cooled below 38 degrees Celsius (100 degrees Fahrenheit).

Certain standby turbine installations are in environments that can be lower than these temperatures, especially AFW pump turbines which are installed out-of-doors. Though certain plants have heaters for their governor or actuator oil, heated oil typically is not circulated until turbine startup. As a result, governor and actuator oils of higher viscosities may not be sufficiently fluid to close the turbine governor valve in time to prevent a turbine overspeed trip during initial cold quick-starts at ambient temperatures below 38 degrees Celsius (100 degrees Fahrenheit) to 54.4 degrees Celsius (130 degrees Fahrenheit) (depending on the viscosity of the oil used).

Woodward literature states that governor and EGR actuator operation can be sluggish due to excessive oil cooling. Certain reported unexplained overspeed trips during cold quick-starts could have been caused by viscous (thick) governor oil not being able to flow through small passages in the governor (or EGR actuator) such as the compensation needle valve port, and hence not rapidly close the governor valve to prevent a turbine overspeed trip.

Viscous oil makes it difficult for the integral oil pump of a governor, or actuator, to prime itself and to force oil through certain small passages of the governor and actuator, in the initial few seconds of a turbine cold quick-start. Slow oil pressure build-up in hydraulic governors and

⁸There is no equivalent ISO-Viscosity number for SAE multi-viscosity oils.

actuators could result from inadequate pump priming with viscous oil, caused by the governor, or actuator, pump taking suction from the turbine oil sump through a small [approximately 1/8-inch iron pipe size (IPS)] line.

An annual report of completed changes, tests, and experiments submitted to the NRC by the licensee of a BWR in 1989 stated that the plant had completed a RCIC turbine governor control oil system modification designated as Terry Design Improvement DI-6, revision 1, dated April 28, 1978.⁹ This design improvement adds an oil sump to EGR actuators used with EG-M governors. The oil sump provides an oil supply to the actuator's oil pump, enhancing oil pressure buildup and governor valve response time during a turbine cold quickstart.

4.3 Other Speed Control System Factors

Historically, turbine-driver overspeed trips during cold quick-starts have been identified as a major source of standby pump unreliability. The following valve design factors affect turbine overspeed and trips:

The specific types of valves discussed below are required to open or close (as appropriate) rapidly, and in coordination, to prevent an excessive turbine steam supply causing turbine overspeed and trip. HPCI and RCIC system turbine control diagrams (Figures 3 and 4 respectively) show the involved valves for those systems. Because of the plant-specific differences in the design of AFW systems, which are within the architect engineer's (AE's) design scope and scope of supply, Terry-Turbodyne could not provide an AFW control diagram.

- Governor valves—These valves are in the Terry scope of design and supply. AFW and RCIC governor valves are fully open at the beginning of a quick-start (they open during the previous turbine stop as inlet steam pressure decreases). The governor valve is designed to assume speed control during startup when the turbine speed reaches the governors minimum speed setting (approximately 2000 rpm).¹⁰ The turbine accelerates rapidly to the minimum speed setting. At that time, the governor valve begins to close to control turbine speed. The turbine, however, overshoots the minimum speed (If a turbine accelerates too fast, it could overspeed at this time before the governor can slow it down), starts to slow down (as the governor valve closes) and then accelerates again as the governor valve opens in re-

sponse to the governor's controlled increase to rated speed. To reduce the possibility of turbine overspeed at this time, hydraulic governors may contain a governor oil flow restriction, called a ramp bushing. This bushing controls and limits the time for the turbine to reach rated speed to 25–35 seconds for a mechanical governor already at operating speed (for a 30 second design startup) after the governor gains control. (Woodward electronic governors contain a ramp-generator circuit that performs the same function as the ramp bushing.) If inlet steam flow is excessive during a quick-start, the governor valve can not close sufficiently to limit speed before the turbine overspeeds.

HPCI governor valves are spring loaded in the closed position at the beginning of turbine startup and must open in coordination with the HPCI turbine steam admission valve (discussed below) to prevent turbine overspeed during quick-starts. Figure 5 shows significant parameters during a HPCI quick-start transient before and after the installation of the modification in GE SIL 480 dated February 3, 1989, which enhances HPCI turbine governor response for cold quick-starts.

- AFW and RCIC turbine steam admission valves—These valves are motor-operated. Except when the valves are also the Terry-supplied trip and throttle valve, as discussed below, they are within an AE's scope of supply. To prevent turbine overspeed, the speed of operation of these valves must not be so rapid that they open excessively prior to the governor valve gaining control of steam flow to the turbine. The rate of valve opening is determined by the speed of the electric motor and the gearing in the valve operator.

In certain cases, AFW steam admission valves are not supplied by Terry. Selection of the correct valve operator is necessary to ensure coordination between the opening of the AFW steam admission valves and the closing of the governor valve (including adequate design margins for the maximum range of variables such as temperature and voltage) to prevent TDAFWP overspeed. Failure to assure coordination under certain conditions could be another factor in TDAFWP overspeeds during cold quick-starts which have been attributed to "unknown" causes. Typically, gate valves are used in this service. One characteristic of gate valves is that a large percentage of flow is passed in the first 25 percent to 30 percent of the valve stem travel (stroke). While not decreasing the valve's stroke time, the use of globe or cage type control valves would result in a more gradual admission of steam to the turbine. This more controlled steam admission would give the governor

⁹General Electric Company, San Jose, California, stated that they issued field instructions to all affected BWRs in February 1976 defining installation of the RCIC turbine EG-R actuator oil sump as identified in Terry Design improvement No. 6 (DI-6).

¹⁰GE stated that to achieve maximum control of the turbine quick start transient, the governor minimum speed setting (idle speed) should be set as low as possible, i.e., 750–1000 RPM.

TURBINE GOVERNOR CONTROL SYSTEM

Courtesy of the
Dresser-Rand Company

Figure 3 Turbine Governor Control System

Figure 4 RCIC

HPCI System

* Ramp Generator Signal Converter

Figure 5 Profile of Significant Cold Quick-Start Parameters

additional time to gain control of turbine speed without degrading the turbine start time.

Certain AFW system designs specify that their AFW turbines use the trip and throttle valve supplied by Terry as the steam admission valve. This design requires the trip and throttle valve to be closed at turbine startup, and coordinated with the rapid closure of the governor valve to prevent an overspeed trip. This coordination is in the AE's scope of design. Turbine steam admission valves have experienced sufficient leakage to permit turbines to "roll" when a steam admission valve is closed. Such leakage with a trip valve used as a steam admission valve could prevent complete steam cut-off during a trip. This leakage results in a hot, wet environment around the governor valve stem which causes the governor valve's nitrided stem to develop scale on its surface. This scale can degrade governor valve response time and lead to unstable turbine operation and overspeed trips. Using the trip valve as a turbine steam admission valve increases the probability of this valve leaking, resulting in condensate buildup in the turbine which could contribute to turbine overspeed during cold quick-starts, especially if the steam inlet lines were not kept free of condensate; this phenomenon was addressed in NRC Office of Inspection and Enforcement (IE) IN 86-14 (Ref. 7) and IN 86-14, Supplement 1 (Ref. 8).

- HPCI turbine inlet steam admission valves—These valves are designed and provided by Schutte & Koerting (now Ketema) and are within the scope of design and supply of both Terry and GE. One of these valves is installed downstream of each HPCI turbine steam supply valve. These valves open in response to a balance of turbine steam pressure and turbine lube oil hydraulic pressure. To ensure against a turbine overspeed trip caused by bypassing the turbine governor acceleration control system, these valves must be sequenced to open after the opening of the steam supply valve. This required sequencing is accomplished by starting the HPCI turbine AOP, which supplies hydraulic pressure for opening this valve (immediately after the turbine steam supply valve begins to open). This sequencing requirement and the need to perform standby turbine cold quick-start surveillance tests to assure the operability of the HPCI and RCIC systems were identified in GE SIL 336 dated July 11 1980, and amplified by Revision 1 of this SIL, dated December 8, 1989.
- The turbine trip and throttle (T & T) valve (also called the trip valve)—According to Terry, this valve is designed to be open at turbine startup and to remain open until it is tripped closed. It is operated by a motor operator such as Limitorque, except when being tripped closed. Trip closures are mechanical at all

commercial reactor plants where Terry turbines are installed. Certain plants have standby turbines equipped with a separate, redundant, electric solenoid trip. Figure 2 is an illustration of a Terry turbine mechanical trip system. As stated above, the trip and throttle valve also functions as the turbine steam admission valve for certain AFW systems. As indicated in NRC Preliminary Notice of Unusual Occurrence, PNO II-90-47 (Ref. 9) certain trip and throttle valves can not be cycled more than 3 times (following Terry turbine trips) in 5 minutes because of Limitorque valve operator thermal overload considerations based on the operator's motor duty rating. Additionally, DC powered valve operators are subject to decreased thrust capability under elevated environmental temperatures. Under certain conditions, a 5 minute rating on the valve operator may not be possible. These factors bound operator actions in the event of turbine trips, thus potentially affecting AFW, HPCI and RCIC system reliability.

5 CHALLENGES TO STANDBY TURBINE-DRIVEN PUMPS

Challenges to TDAFWPs tend to differ from those experienced by HPCI and RCIC turbine-driven pumps. The factors relating to each application, and the implications for turbine performance and reliability, are discussed in the following sections.

5.1 Challenges to AFW Pump Turbine-Drivers

Actuation signals for AFW pump turbine-drivers are diverse. PWR USARs contained 23 different and site-specific actuation signals, which are listed in Appendix B, as are 7 PWR plants that do not actuate their TDAFWPs using a quick-start. During a typical post-trip demand start, the motor-driven AFW pumps (MDAFWPs) actuate on loss of all main feedwater pumps (MFPs), main feedwater isolation (MFI), or low-low water level in a single steam generator (SG). Typically, TDAFWPs do not actuate until there is a low-low level in more than one SG. This delay typically permits the MDAFWPs to reach maximum pump flow (100 percent to 200 percent of AFW requirements) prior to initiation of a TDAFWP quick-start.

A primary failure mode of TDAFWPs is turbine overspeed trip during quickstart. TDAFWPs during normal demand starts discharge against MDAFWP pressure, especially for units having two 100 percent capacity MDAFWPs. Discharging against an accumulator effect of MDAFWP discharge pressure should reduce TDAFWP cold quick-start turbine oscillations and overspeed trips, particularly for demand starts occurring at relatively low reactor power, when the resultant post-trip AFW demand is relatively low. A TDAFWP typically can supply 100 per-

cent of required flow. Section 7.1 discusses findings related to TDAFWP reliability following challenges.

5.2 Challenges to HPCI and RCIC Pump Turbine-Drivers

HPCI and RCIC turbine-driven pumps historically have experienced demands on the order of about once every 2.5 reactor years. Thus, most failure data (such as that discussed in Section 7 of this report), and historical evidence of turbine operability, are primarily derived from surveillance testing. This testing varies in both frequency and methodology, and in some cases may not closely simulate the dynamic response assumed for the safety function of the standby pump as addressed in Section 6.0.

6 SURVEILLANCE TESTS OF STANDBY PUMPS

During an analysis in this study to determine why certain plants reported no failures of standby turbines and governors from 1985 through 1990, while other plants had several failures, differences in surveillance testing were identified. A review of NPRDS failure reports and individual plant Technical Specifications (TS), as well as discussions with NRC resident inspectors, and with utility plant personnel, identified the testing variations discussed below.

PWR plants typically have monthly pump operability surveillance tests required by their TS, which are typically initiated by a standby pump turbine quickstart. Some tests are hot quick-starts. A hot quick-start refers to a quick-start initiated after an initial cold slow-start, where any condensate in the inlet steam line has been drained, and the system is warmed up and possibly checked for factors that could cause a quick-start to fail. BWRs typically have TS surveillances quarterly for pump operability. Some BWRs initiate this test with a hot or cold turbine quick-start, while some may use a slow start with the turbine speed initially brought to the slow speed stop.

TS for PWR and BWR plants typically require a simulated actuation of the automatic start of the turbine-driven AFW, or the HPCI and RCIC pumps with a periodicity of once a fuel cycle, or once every 18 months. Though plant-specific Technical Specifications may require only one AFW, HPCI or RCIC turbine-driven pump auto-initiation quick-start every operating cycle, or 18 months, certain PWR and BWR plants initiate each pump flow test with a cold quick-start. Certain BWR plants may perform only one cold quick-start for each turbine-driven pump during a fuel cycle; other BWR plants may perform four or more cold quick-starts on each turbine-driven pump during a fuel cycle; and some BWR and PWR plants may not be required to perform either a cold, or a hot, quick-start.

For certain later plants licensed to the Standard Technical Specifications, Section 4.0.5 of the Technical Specifications, or the equivalent plant-specific specification section, covers the in-service testing (IST) requirements for pumps in accordance with the applicable edition of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (BPV) Code, Section XI, Article IWP-1000, "PUMP TESTING." Such testing is required by 10 CFR Part 50.55(g), which specifies that testing of safety-related standby pumps be accomplished in accordance with ASME/ANSI Standard "Operation and Maintenance of Nuclear Power Plants," Addenda ASME/ANSI OMa-1988, Part 6. This standard does not address the testing, or operability, of pump turbine-drivers, which historically have been identified as the cause of the majority of failures of these standby pumps.

GE stated in its SILs for HPCI and RCIC turbines as early as 1980 that only cold quick-starts provide a valid indication of turbine operability for standby turbine-driven pumps. In 1986, INPO recommended cold quick-starts for testing all standby turbine-driven pumps. The BWOG has recommended that each utility review their AFW (EFW) surveillance and test procedures to ensure that components used in emergency and abnormal operating procedures are tested as nearly as possible to operating conditions to demonstrate AFW system and component operability. As stated in NRC IN 88-09 (Ref. 10), reliability problems are more evident when TDAFWPs are periodically tested using cold quick-starts. The operational feedback documents support the importance of surveillance testing which duplicates actual demand actuation conditions.

7 OPERATING EXPERIENCE

A review of operating experience data from LERs and NPRDS indicated that the same types of failures of Terry turbine-drivers and governors used for AFW, HPCI, and RCIC systems' pumps that were observed during the 1980s are still occurring. The types of failures identified during this study, described in detail in Section 7.4 of this report, appear to be largely avoidable by effective utilization of manufacturers' maintenance procedures and industry experience. The present study identifies previously unidentified failure initiators, extends standby turbine failure data analysis through December 1992, and confirms the findings of EPRI Report NP 4264 and NUREG/CR-5404 (Ref. 3). Significant findings are addressed in Sections 7.1 through 7.7.

7.1 Turbine-Driven AFW Pump Demand Reliability

Although a design basis for TDAFWPs is to operate as a stand-alone pump when the MDAFWPs are not available during a station blackout, essentially all TDAFWP

demand actuations occur in conjunction with, and follow, MDAFWP actuation, as discussed in Section 5.1. As a result, typical demand starts following a reactor trip are not a measure of TDAFWP reliability for its stand-alone safety function. Certain LERs reviewed during this study, and conversations with a resident inspector, indicate that following a reactor trip (especially at lower power), the TDAFWP is not needed and is secured immediately after its demand start, so quickly that it could preclude a TDAFWP overspeed trip. Securing the TDAFWP typically is required to prevent excessive post-trip reactor cool-down, since two MDAFWPs provide 100 percent to 200 percent of AFW flow requirements, and the TDAFWP provides another 100 percent. Certain other LERs identified that following a reactor trip from as high as 100 percent thermal power, the MDAFWPs were adequate to maintain SG levels without actuating the plant's TDAFWP. The number of valid TDAFWP auto-initiations mimicking stand-alone TDAFWP operation (without prior or concurrent starts of the MDAFWPs), such as required for a station blackout event, is so small as to be insignificant for determining TDAFWP reliability.

As addressed in Appendix B, a review of information available in LERs (reactor trips and ESF actuations reportable in accordance with 10 CFR 50.73) and USARs (USAR turbine-driven pump initiation signals were used to judge TDAFWP demand actuation when an LER was not explicit) indicated that for the years 1987 through 1990, TDAFWPs at plants having MDAFWPs virtually always started following a start of the MDAFWPs. A number of factors appear to limit the generic applicability of industry-wide TDAFWP failure data for reliability determinations for a specific TDAFWP installation, especially as a stand-alone TDAFWP. These factors include 1) plant-specific differences in installed AFW systems; 2) the 23 different plant-specific parameters used to start TDAFWPs; 3) the wide differences in TDAFWP turbine speed and horsepower, as well as steam inlet pressures discussed in Section 4.1.1; and 4) the differences in NSSS vendor practices in tripping the MFW pumps after a reactor trip.¹¹

The synergistic effect of MDAFWPs in enhancing apparent TDAFWP reliability appears to be substantiated by LERs of reactor trips submitted by one PWR plant during the third and fourth quarters of 1987 which identified no problems with the operation of TDAFWPs during post-trip operation in conjunction with MDAFWPs. During that same period, NPRDS failure reports from the same plant identified problems encountered with stand-alone tests of the TDAFWPs involving turbine speed in-

stabilities and overspeed trips requiring modifications to the governors.

Analysis of LERs for the period January 1987 through December 1992 identified a total of 21 failures to start and run on actual demand out of a total of 292 demands, for a demand probability of $7.2\text{E-}2$. Removing the 2 cases of TDAFWP unavailability due to maintenance results in a demand probability of $6.5\text{E-}2$ per demand. All failures were caused by turbine trips, except for three which were caused by an improper switch setting, a bearing failure, and a loose electrical connection. The data supporting these analyses are found in Appendix B, including Table B-1 which lists demand failures for TDAFWPs and causes. This data does not include events where the TDAFW did not actuate and inject, based on review of Safety Analysis Reports and discussions with resident inspectors.) In comparison with this study, the demand probability used in NUREG-1150 (Ref. 2), the Surry Probabilistic Risk Assessment (PRA), was $1.1\text{E-}2$, excluding maintenance unavailability, with an estimated upper bound of $3.5\text{E-}2$. The Surry IPE used a TDAFWP failure-to-start generic demand probability of $4.2\text{E-}2$ and a plant-specific demand probability of $2.5\text{E-}2$. Estimates of demand probability for PRAs usually include surveillance testing as well as actual demands, with the major contribution being from surveillance testing. Consequently, the demand probability in this study is higher than plant-specific values used in PRAs.

7.2 HPCI and RCIC Pump Demand Reliability

Analysis of demand starts for turbine-driven HPCI and RCIC pumps was based on the review of LERs for the period of January 1987 through December 1992. This analysis identified one failure in 52 demands for the HPCI pumps 1987-1992, for a probability of $1.9\text{E-}2$. The HPCI failure was caused by the failure of a flow controller. There was one case of HPCI unavailability. One RCIC failure was identified in 76 demands, for a demand probability of $1.3\text{E-}2$. The RCIC failure was caused by a turbine overspeed trip. There were 2 cases of RCIC pump unavailability. (The data supporting these analyses are found in Appendix B, including Table B-2 which lists the demand failures for HPCI and RCIC pumps with failure causes.) In comparison with this study, in modeling Peach Bottom for the NUREG-1150 PRA (Ref. 11), the demand probability of $3.0\text{E-}2$ was used for both HPCI and RCIC (excluding maintenance unavailability). The demand probability for RCIC in the Peach Bottom IPE was $4.96\text{E-}2$.

7.3 Plant-Specific Differences in Turbine-Driven Standby Pump Reliability

This study indicated that plant-specific differences in such areas as system design, installation and environment,

¹¹Westinghouse plants typically trip the MFW pumps and isolate MFW, whereas Combustion Engineering designs typically run the MFW pumps back to the low speed speeds.

maintenance, installed modifications, surveillance testing, and failure reporting thresholds could result in variations in reported turbine failures. Where AFW system design was plant-specific and performed by an AE (in lieu of being generic and performed by the NSSS vendor as was the case with HPCI and RCIC for BWR plants), plant-specific differences could be a significant factor in differences in reported failures of AFW turbines, especially in the area of adequate draining of steam supply lines to TDAFWPs. Similarly for BWR plants, plant-specific differences in the implementation of design changes proposed at the INPO-sponsored seminar held in February 1981 and proposed GE modifications for HPCI and RCIC turbines, such as those contained in SILs, could be a significant factor for differences in reported failures of these turbines. An example of this is addressed in Section 4.2 relative to DI-6. GE proposed this improvement for all plants in their NSSS scope of supply in 1976, but one older BWR plant did not install this change until 1989. Other BWR plants may not have installed this change to date, nor may PWR plants which do not receive GE modifications.

Table 4 shows the number of failures reported to NPRDS and failure rates per calendar hour for standby turbine-drivers and key valves for 1985 through 1992. Analysis of the data did not identify a basis for the data trends.

Though certain AFW turbines and controls are identical or similar to RCIC turbines and controls, the number of overall failures of AFW turbine assemblies appears disproportionately higher. This difference could be influenced by such factors as the following:

- PWRs typically test and operate their TDAFWPs more often than BWRs test and operate HPCI and RCIC pumps (for example, monthly versus quarterly flow testing). This affords a greater number of opportunities to detect failed conditions, which could make the turbine more vulnerable to cyclic wear if cold quick-starts are employed without adequate lubrication, as discussed in Section 4.1.2. This could be significant for plants that do not inspect or replace bearings every 5 years, as addressed in later Terry manuals. Where TDAFWP tests are based solely on the satisfactory opening of the TDAFWP pump discharge valve, proper operation of the TDAFWP may not be verified, since the discharge valve can open and the test can be terminated prior to the turbine reaching full speed and stabilizing. Tests have identified these valves opening in 8 seconds for turbines whose governors have a 30 second ramp bushing.
- Certain TDAFWPs are installed out-of-doors, or in other locations where low ambient temperatures could cause problems, such as causing the governor oil to be above its maximum viscosity limit for proper governor operation, as discussed in Section 4.2.

- Certain AFW turbines do not have pressurized turbine lube oil systems, as discussed in Section 4.1.2. A lack of oil pressure during quickstarts, or of adequate oil cleanliness could lead to bearing failures and start-up instabilities, which do not occur with HPCI and RCIC turbines that have pressurized and filtered oil systems.
- As discussed in Section 4.3, certain AFW turbine installations use the trip and throttle valve as the turbine inlet steam admission valve. The gearing of Limitorque operators for turbine inlet steam admission valves must meet required turbine steam admission rates for quick-starts, but must not result in an overspeed trip before the governor can close the governor valve from its full open position [in the standby condition] to a valve position representing rated pump flow.
- For TDAFWP installations, the distance between the steam admission valve and the turbine varies. The greater the distance, the greater the potential volume of condensate if the steam admission valve leaks. Such condensate has caused turbine overspeed and trip when the stop valve opened for a normal demand quick-start. As discussed in Section 4.3, this phenomenon was addressed in NRC Office of Inspection and Enforcement IN 86-14 (Ref. 7), and Supplement 1 (Ref. 8).

7.4 Recurring Standby Turbine Failures Identified in LERs and NPRDS Failure Reports

Detailed review and analysis of LERs and NPRDS failure narratives, and extensive discussions with Dresser-Rand (Terry) and Woodward and with plant personnel identified the failures and failure initiators discussed in Sections 7.4.1 through 7.6.

7.4.1 Governor Failures

The most significant category of failures of standby turbine assemblies appeared to be those involving the turbine governor assembly. The types of failures identified during this study and discussed below appear to be largely avoidable by performing maintenance prescribed by Terry and Woodward with periodicities shortened if required for plant-specific conditions:

- Eighteen LER-reported failures involved calibration anomalies for all identified governor types, including electronic calibration set-point drift of Woodward type EG-M governor systems. For examples, see Appendix C, Example 1.
- Eleven LER-reported failures of EG-M governor system ramp-generator electronic modules resulted

NPRDS IDENTIFIED COMPONENT FAILURE RATES IN COMMERCIAL CALENDAR HOURS												
	1985			1986			1987			1988		
	No. Failures	No. Comm. Cal. Hrs.	Failures/Comm. Cal. Hr.	No. Failures	No. Comm. Cal. Hrs.	Failures/Comm. Cal. Hr.	No. Failures	No. Comm. Cal. Hrs.	Failures/Comm. Cal. Hr.	No. Failures	No. Comm. Cal. Hrs.	Failures/Comm. Cal. Hr.
AFW Pump Turbine	14	5.1x10 ⁵	2.7x10 ⁻⁵	24	5.6x10 ⁵	4.3x10 ⁻⁵	18	5.9x10 ⁵	3.1x10 ⁻⁵	13	6.2x10 ⁵	2.1x10 ⁻⁵
AFW Pump Turbine Governor	21	4.7x10 ⁵	4.5x10 ⁻⁵	9	5.0x10 ⁵	1.8x10 ⁻⁵	12	5.3x10 ⁵	2.3x10 ⁻⁵	18	5.6x10 ⁵	2.9x10 ⁻⁵
HPCI Pump Turbine	7	1.8x10 ⁵	3.9x10 ⁻⁵	6	1.9x10 ⁵	3.2x10 ⁻⁵	7	2.0x10 ⁵	3.5x10 ⁻⁵	5	2.1x10 ⁵	2.4x10 ⁻⁵
HPCI Pump Turbine Governor	6	2.2x10 ⁵	2.7x10 ⁻⁵	1	2.2x10 ⁵	4.5x10 ⁻⁶	7	2.3x10 ⁵	3.0x10 ⁻⁵	0	2.4x10 ⁵	0
HPCI Pump Turbine Main Steam Isolation Valve	14	1.8x10 ⁵	7.8x10 ⁻⁵	6	1.9x10 ⁵	3.2x10 ⁻⁵	3	2.0x10 ⁵	1.5x10 ⁻⁵	7	2.1x10 ⁵	3.3x10 ⁻⁵
HPCI Pump Turbine Main Steam Isolation Valve Operator	3	1.8x10 ⁵	1.7x10 ⁻⁵	5	1.9x10 ⁵	2.6x10 ⁻⁵	1	2.0x10 ⁵	5.0x10 ⁻⁶	7	2.1x10 ⁵	3.3x10 ⁻⁵
HPCI Pump Turbine Trip Stop Valve	2	1.8x10 ⁵	1.1x10 ⁻⁵	2	1.9x10 ⁵	1.1x10 ⁻⁵	2	2.0x10 ⁵	1.0x10 ⁻⁵	1	2.1x10 ⁵	4.8x10 ⁻⁶
HPCI Pump Turbine Trip Stop Valve Operator	5	1.8x10 ⁵	2.8x10 ⁻⁵	0	1.9x10 ⁵	0	2	2.0x10 ⁵	1.0x10 ⁻⁵	1	2.1x10 ⁵	4.8x10 ⁻⁶
RCIC Pump Turbine	10	2.0x10 ⁵	5.0x10 ⁻⁵	4	2.1x10 ⁵	1.9x10 ⁻⁵	7	2.3x10 ⁵	3.0x10 ⁻⁵	3	2.6x10 ⁵	1.2x10 ⁻⁵
RCIC Pump Turbine Governor	3	2.0x10 ⁵	1.5x10 ⁻⁵	3	2.1x10 ⁵	1.4x10 ⁻⁵	3	2.3x10 ⁵	1.3x10 ⁻⁵	5	2.5x10 ⁵	2.0x10 ⁻⁵
RCIC Pump Turbine Main Steam Supply Isolation Valve	0	1.9x10 ⁵	0	3	2.1x10 ⁵	1.4x10 ⁻⁵	4	2.2x10 ⁵	1.8x10 ⁻⁵	7	2.5x10 ⁵	2.8x10 ⁻⁵
RCIC Pump Turbine Main Steam Supply Isolation Valve Operator	2	1.9x10 ⁵	1.1x10 ⁻⁵	3	2.1x10 ⁵	1.4x10 ⁻⁵	1	2.2x10 ⁵	4.5x10 ⁻⁶	3	2.5x10 ⁵	1.2x10 ⁻⁵
RCIC Pump Turbine Trip Stop Valve	6	2.0x10 ⁵	3.0x10 ⁻⁵	0	2.2x10 ⁵	0	0	2.4x10 ⁵	0	1	2.7x10 ⁵	3.7x10 ⁻⁶
RCIC Pump Turbine Trip Stop Valve Operator	10	1.9x10 ⁵	5.3x10 ⁻⁵	3	2.1x10 ⁵	1.4x10 ⁻⁵	4	2.2x10 ⁵	1.8x10 ⁻⁵	4	2.5x10 ⁵	1.6x10 ⁻⁵

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TABLE 4

NPRDS COMPONENT FAILURE RATES IN COMMERCIAL CALENDAR HOURS

NPRDS IDENTIFIED COMPONENT FAILURE RATES IN COMMERCIAL CALENDAR HOURS												
	1989			1990			1991			1992		
	No. Failures	No. Comm. Cal. Hrs.	Failures/Comm. Cal. Hr.	No. Failures	No. Comm. Cal. Hrs.	Failures/Comm. Cal. Hr.	No. Failures	No. Comm. Cal. Hr.	Failures/Comm. Cal. Hr.	No. Failures	No. Comm. Cal. Hr.	Failures/Comm. Cal. Hr.
AFW Pump Turbine	5	6.3x10 ⁵	7.9x10 ⁻⁶	24	6.4x10 ⁵	3.8x10 ⁻⁶	12	6.5x10 ⁵	1.8x10 ⁻⁶	8	5.9x10 ⁵	1.3x10 ⁻⁶
AFW Pump Turbine Governor	6	5.7x10 ⁵	1.1x10 ⁻⁶	27	5.7x10 ⁵	4.7x10 ⁻⁶	10	6.0x10 ⁵	1.7x10 ⁻⁶	8	6.0x10 ⁵	1.8x10 ⁻⁶
HPCI Pump Turbine	3	2.1x10 ⁵	1.4x10 ⁻⁶	6	2.2x10 ⁵	2.7x10 ⁻⁶	6	2.2x10 ⁵	2.7x10 ⁻⁶	5	2.1x10 ⁵	2.4x10 ⁻⁶
HPCI Pump Turbine Governor	5	2.4x10 ⁵	2.1x10 ⁻⁶	2	2.5x10 ⁵	8.0x10 ⁻⁶	1	2.4x10 ⁵	4.2x10 ⁻⁶	3	2.4x10 ⁵	1.3x10 ⁻⁶
HPCI Pump Turbine Main Steam Isolation Valve	5	2.1x10 ⁵	2.4x10 ⁻⁶	5	2.2x10 ⁵	2.3x10 ⁻⁶	9	2.0x10 ⁵	4.5x10 ⁻⁶	9	1.9x10 ⁵	4.7x10 ⁻⁶
HPCI Pump Turbine Main Steam Isolation Valve Operator	4	2.1x10 ⁵	1.9x10 ⁻⁶	1	2.2x10 ⁵	4.5x10 ⁻⁶	5	2.0x10 ⁵	2.5x10 ⁻⁶	3	1.9x10 ⁵	1.6x10 ⁻⁶
HPCI Pump Turbine Trip Stop Valve	0	2.1x10 ⁵	0	2	2.2x10 ⁵	9.1x10 ⁻⁶	5	2.2x10 ⁵	2.3x10 ⁻⁶	1	2.1x10 ⁵	4.8x10 ⁻⁶
HPCI Pump Turbine Trip Stop Valve Operator	0	2.1x10 ⁵	0	0	2.2x10 ⁵	0	1	2.2x10 ⁵	4.3x10 ⁻⁶	0	2.1x10 ⁵	0
RCIC Pump Turbine	2	2.6x10 ⁵	7.7x10 ⁻⁶	6	2.7x10 ⁵	2.2x10 ⁻⁶	6	2.7x10 ⁵	2.2x10 ⁻⁶	4	2.6x10 ⁵	1.5x10 ⁻⁶
RCIC Pump Turbine Governor	1	2.5x10 ⁵	4.0x10 ⁻⁶	5	2.6x10 ⁵	1.9x10 ⁻⁶	7	2.7x10 ⁵	2.6x10 ⁻⁶	6	2.7x10 ⁵	2.2x10 ⁻⁶
RCIC Pump Turbine Main Steam Supply Isolation Valve	4	2.5x10 ⁵	1.6x10 ⁻⁶	7	2.6x10 ⁵	2.7x10 ⁻⁶	1	2.6x10 ⁵	3.8x10 ⁻⁶	3	2.5x10 ⁵	1.2x10 ⁻⁶
RCIC Pump Turbine Main Steam Supply Isolation Valve Operator	1	2.5x10 ⁵	4.0x10 ⁻⁶	4	2.6x10 ⁵	1.5x10 ⁻⁶	2	2.6x10 ⁵	7.7x10 ⁻⁶	4	2.5x10 ⁵	1.6x10 ⁻⁶
RCIC Pump Turbine Trip Stop Valve	1	2.7x10 ⁵	3.7x10 ⁻⁶	2	2.8x10 ⁵	7.1x10 ⁻⁶	3	2.8x10 ⁵	3.6x10 ⁻⁶	1	2.7x10 ⁵	3.7x10 ⁻⁶
RCIC Pump Turbine Trip Stop Valve Operator	4	2.5x10 ⁵	1.6x10 ⁻⁶	2	2.6x10 ⁵	7.7x10 ⁻⁶	4	2.6x10 ⁵	1.5x10 ⁻⁶	6	2.5x10 ⁵	2.4x10 ⁻⁶

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TABLE 4 (Continued)

NPRDS COMPONENT FAILURE RATES IN COMMERCIAL CALENDAR HOURS

in the failure of electric governors to maintain the required turbine speed. For examples, see Appendix C, Example 2.

- Seven LER-reported failures of model EGR electro-mechanical-hydraulic actuators used with EG-M governor systems to operate the turbine governor valve were identified. These actuators replicate a Woodward type PG governor's actuator section.¹²
- Six LER-reported failures were identified which resulted from electrical grounds in EG-M governor systems and model EGR actuators. These components use direct current (DC) circuits that are designed to be operated ungrounded. Grounding the positive and negative sides of these ungrounded 2-wire DC control circuits at different points can result in failures for which there may be no failure analysis.¹³
- Failures to maintain the design configuration of parts during governor refurbishment were identified. These failures are discussed in Section 7.5.
- Two examples of loss of turbine speed control were caused by the loss of instrument air to TDAFWP PG-PL and PGA mechanical-hydraulic governors. This failure mechanism is discussed in Section 7.6.
- Certain failures for which no cause was identified could have been caused by viscous oil during cold quick-starts. See Section 4.2 for the effects of cold starts at ambient temperatures of less than 38 degrees Celsius (100 degrees Fahrenheit) to 112 degrees Celsius (130 degrees Fahrenheit) depending on oil viscosity, which can exist for TDAFWPs.
- NRC IN 90-51 (Ref. 12) identified failures of Woodward electronic type EG-M governors, used with HPCI, RCIC, and certain AFW turbines, caused by the failure of the governor power supply dropping resistor, which reduces voltage from 125 VDC to 48 VDC (or 24 VDC). This study identified 7 LERs and 3 NRC inspection reports (Ref. 13) and (Ref. 14) documenting failures of these voltage dropping resistors in type EG-M governors used with safety-related standby turbines from 1976 to 1993 which were not addressed in (Ref. 12), or in Supplement 1 to IN 90-51 (Ref. 15), issued while this study was in progress,

which identified a replacement resistor designed to preclude future failures.¹⁴

- Governor failures caused by contamination of governor oil with water were identified. Contamination was typically caused by leakage through the turbine inlet steam admission valve.¹⁵ Woodward has for many years identified contaminated governor oil as a primary cause of governor failure.

7.4.2 Other Turbine Control System Failures

Failures of the turbine control system components identified during the study and discussed below were significant factors in standby turbine failures.

- Five LER-reported failures of turbine-driver pump flow control units were identified.¹⁶
- Four LER-reported failures of turbine steam inlet valve limit switches to initiate turbine governor ramp starts were identified. Failure or mispositioning of these switches causes turbine failure.¹⁷
- Three LER-reported turbine failures were identified that were caused by dirty governor linkages binding and affecting the proper operation of governor valves. This subject is addressed in Section 7.7.¹⁸
- Turbine-trip on overspeed due to coordination between the steam admission and governor valves was identified as a possible cause of failures.¹⁹
- Failures of Terry turbine overspeed trip mechanism ball-type tappets were identified. This subject is discussed in Section 2.3.

7.4.3 Turbine Related Failures

Turbine failures identified in this study are discussed below.

- Eight LER-reported turbine failures were identified which were caused by the mispositioning of valves in standby turbine lube-oil systems, that resulted in the

¹⁴The LERs identified during this study are 260/76-013/03L; 278/76-052/3L; 259/77-022; 293/80-085/03L-0; 324/81-039/3L-0; 263/83-002/3L-0; 277/87-020-01; and 321/90-001-00.

¹⁵See LER 05000331/78-025. NPRDS also identified failures in this area.

¹⁶See LERs 05000271/80-013/03L-0; 05000293/80-019/03L-0; 05000293/80-024/03L-0; 05000327/82-006/03L-0; 05000327/87-006-00.

¹⁷See LERs 05000325/81-010/03L-0; 05000348/82-028/03L-0; 05000348/83-049/03L-0; 05000366/81-125/03L-0.

¹⁸See LERs 05000333/76-037; 05000298/77-017 05000254/78-003. Several NPRDS failure reports address this area.

¹⁹Trips with unidentified causes could result from a lack of coordination between a turbine's steam inlet stop valve and governor valve, which permits the introduction of excess steam into the turbine and turbine overspeed before the governor can control.

¹²See LERs 05000260/79-013; 05000324/78-039; 05000324/79-013; 05000325/78-039; 05000259/80-079/03L; 05000298/77-040; 05000271/80-007. NPRDS also identified failures in this area.

¹³See LERs 05000296/76-005; 050000324/77-071; 05000324/81-137/03L-0; 05000333/89-005-00; 05000333/89-019-00; 05000277/86-016-01. NPRDS also contains failures in this area. See Appendix A for additional details.

loss of oil pressure, or in draining the turbine lube-oil sump; or by clogged or dirty oil filters, causing turbine failures. The valves typically mispositioned were supplied with the turbine assembly and not shown on the plants' Piping and Instrumentation Diagrams (P&IDs). For examples, see Appendix C, Example 3.

- Six LER-reported failures of HPCI auxiliary oil pumps (AOPs) were identified which resulted in HPCI turbine failures.²⁰
- Twelve LER-reported turbine failures related to general maintenance were identified. Such failures are addressed in Section 7.6. For examples see Appendix C, Example 4.

7.5 Turbine Speed Control Failures from Removal of Governor Modifications during Refurbishment

This study identified a failure initiator potentially applicable to all standby turbines using Woodward governors. An example of this occurred at a site where removal of an apparently uncontrolled governor modification (buffer springs) resulted in reinstallation of improper springs with resultant TDAFWP turbine speed instabilities. The Woodward type PG-PL governors oscillated unacceptably during cold quick-start tests when the TDAFWPs operated independently, causing the turbines to trip on overspeed as reported to NPRDS. LERs reporting reactor trips submitted by the same plant during this period did not identify problems with the operation of TDAFWPs during post-trip operation in conjunction with MDAFWPs.

Another example was a case where an AFW Terry turbine Woodward PG-PL governor was sent by a plant for refurbishment with the governor set for operation in a clockwise direction. The governor was returned set for counter-clockwise operation. The refurbished governor was installed without this change being identified, and the turbine started for post-maintenance testing. With the governor operating in a clockwise direction, its internal pump did not build up hydraulic pressure to close the AFW pump turbine's throttle valve. The turbine's mechanical overspeed trip did not operate properly and the

pump overpressurized the AFW system as turbine speed increased.²¹

The purported cause of both failures was that the plants had sent safety-related governors to the Woodward factory for refurbishment without identifying to Woodward that plant-specific modifications had been made.²² Though the failures involved PWR plants and TDAFWPs, the problem is potentially generic and could occur at BWR plants with HPCI and RCIC turbines. During governor refurbishment, Woodward's standard policy resulted in the governor assemblies being restored to their original factory "as-built" condition and name-plate description, and returned to the plants in their as-manufactured condition. Woodward stated that, without additional instructions from a customer, based on a governor's part number, serial number and nameplate data, governors would be returned to the as-manufactured condition that existed when the governor system originally was shipped from the factory. The data contained in a governor's part number and serial number, and nameplate identify governor-specific control features, such as factory installed buffer-springs and the governor's direction of rotation. The direction of rotation is cast into a governor's base as a two-headed arrow; after the governor is completed and the direction of rotation determined by the governor's as-built configuration, the inappropriate arrowhead is ground off. Certain governors are manufactured to operate in either direction, and have both directional arrows on the governor base.

During factory refurbishment, without specific instructions to the contrary, custom governor parts are replaced with standard parts, based on a governor's part number, serial number, and nameplate data, as stated previously. The removal of custom parts could render a governor inoperable for plant-specific speed control applications affecting plant safety.

Woodward stated that the name plates on governors with site-specific modifications should be marked with the letters "US" to indicate the existence of a modification. Such marking on a returned governor alerts Woodward to the fact that the governor has been modified, and will prevent a governor from being returned to its "as-manufactured" configuration, but does not provide specific details. Additional data on the scope of modification and complete identification of custom parts installed in the field are desirable. It also is desirable to identify plant-specific field conditions affecting, or related to, governor operation. Similarly, modified model EGR actuators should be identified to Woodward when returned for repair, refurbish-

²⁰See LERs 05000296/85-003-00; 05000298/85-011-00; 05000321/81-138/03L-0; 05000324/89-013-00; 05000321/82-012/03L-0; 05000324/84-013-01. NPRDS included failures in this area.

²¹The event was the Rancho Seco AFW overpressure event. See LER 05000312/89-001.

²²Dresser-Rand has stated that they maintain "as-built" records of plant-specific Woodward governor modifications as the 10CFR Part 21 dedicator for Woodward governors supplied by them to licensees. This does not include site-specific maintenance or modifications done without the knowledge of Dresser or its predecessors.

ment, or troubleshooting. Woodward stated that electrical/electronic modules, circuit boards, and cards should not be repaired in the field.

The problems addressed above could have been prevented by an effective design control program and by effective procurement and dedication of the commercial grade parts and services supplied by Woodward as part of governor refurbishment to assure that the refurbished governors met their plant-specific design configuration.

Woodward does not provide design control for their products, except when specifically negotiated with a customer, which normally would not cover plant-specific modifications that were not made by Woodward. For safety-related applications having any level of design control, Woodward uses a prefix of "99" for part numbers. This designation does not indicate plant-specific design control unless such control has been agreed to by Woodward.

Woodward stated that they have supplied governors, services, and replacement parts for use in safety-related applications only as commercial grade items. Prior to use in safety-related applications, these commercial grade items require dedication as required by Title 10 of the Code of Federal Regulations, Part 21. Woodward indicated that its policy of providing only commercial grade items is based on various factors (such as plant-specific design, operation, maintenance, installation, installed environment, and modifications), about which Woodward may not be apprised, nor can they control.

The installation of replacement parts not meeting plant-specific requirements is a potentially generic concern which could affect all Woodward governors that have been modified by an organization other than Woodward, and that are subsequently factory refurbished by Woodward, or have replacement parts provided by Woodward based on factory data, without identifying modifications made after shipment of the governors from the factory. Woodward stated that all governor system modifications performed by their field representatives should be shown on the unit's nameplate. This includes EGR actuators.

Where plants perform post-maintenance and surveillance testing without performing a stand-alone cold quick-start of the turbine-driver, standby pump inoperability resulting from the installation of incorrect parts might not be discovered until a stand-alone cold quick-start demand is initiated.

An example of a similar problem identified by Woodward was the installation by other-than-Woodward of a modified governor drive on the Woodward governor for a safety-related diesel engine. When the drive was replaced, other parts, such as the fly-weights and springs, also re-

quired replacement for proper governor operation. These additional parts were not replaced and the diesel did not operate properly.

7.6 AFW Turbine Governor Failures from the Loss of Instrument Air

Woodward type PG-PL and PGA governors installed on TDAFWPs can use instrument air (IA) to operate remote speed control (not flow control) from the control room. Appendix A describes this mode of operation, and the effect on turbine speed of such an IA failure (fail high or low depending on the specific governor configuration). Woodward stated that an IA pressure variation as small as 3.4 kPa (.5 lbf/in²) could affect turbine speed. This safety-related use of IA was not specifically addressed in previous IA studies nor in NRC Generic Letter 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment" (Ref. 16), which addresses the reliability of IA. The failure of IA for an AFW standby turbine governor is identified as a contributor to core damage frequency in at least one site-specific PRA.²³ One PWR plant reported failures of the IA line to the TDAFWP governor, causing the loss of speed control in February and November 1985. Typically, minor fluctuations in IA are not monitored. Such fluctuations could have been a cause of certain AFW turbine overspeed trips that could not be duplicated and were identified as spurious.

A Terry factory representative stated that capping the Woodward governor remote speed control bellows air connection when it is not used permits room temperature variations to cause fluctuations in pressure on the bellows that change a turbine's set speed. He stated that, in one case during a post maintenance test, with an initial turbine speed setting of 3600 revolutions per minute (rpm) and the room cool. As the pump room heated up, the speed dropped to 3480 rpm. The connection was uncapped and the phenomenon stopped. For reverse acting governors, a pressure increase causes a decrease in turbine speed. For plants having direct acting governors, a pressure increase would cause an increase in turbine speed. A decrease in ambient room temperature could decrease pressure on the bellows (older units may have a diaphragm instead of a bellows) with the opposite effect. Because TDAFWPs are typically subject to changes in temperature, this could be a generic problem affecting TDAFWP operability, including being the root cause of TDAFWP trips whose causes have been identified as "spurious," and "unknown," since temperatures could differ significantly from when a turbine speed setting is made and the turbine is cold quick-started.

²³The involved site is Surry (See Ref 2).

²⁴This failure is described in LER 05000315/85-065-00.

7.7 Lack of Adherence to Vendor-Specified Maintenance

Two factors appeared to dominate standby turbine maintenance-related failures. The first factor is an identified lack of implementation by plants of vendor identified maintenance instructions, and the second factor is the lengthening of vendor maintenance periodicities by plants to suit refueling cycles. For specific examples, see Appendix C, Example 5.

Maintenance actions for specific standby turbine assembly components and piece-parts appeared more frequently to be determined by plant-specific operating experience at the affected sites than by plant analysis of industry operational experience data or of generic correspondence. Examples of such plant-specific determinations of maintenance are the replacement of turbine trip system ball-tappets discussed in Section 2.3, and the requirement for clean turbine and governor oil to assure reliable turbine operation. Woodward technical literature has identified for more than 12 years that contaminated oil can be a dominant factor in governor malfunctions and failures. Failures and problems relating to turbine and governor oil cleanliness were identified as generic concerns as early as April 1978 in NRC Circular 78-02 (Ref. 17), and as recently as NRC IN 90-51, Supplement 1, issued in October 1991. NRC inspection reports 50-424/92-14 and 50-425/92-14²⁵ (Ref. 13), and 50-482/93-01 (Ref. 14) document failures of TDAFWP governor voltage dropping resistors as recently as June and July 1992, and January 1993. Recurring failures of these resistors were addressed in IN 90-51 (Ref. 12) and IN 90-51, Supplement 1 (Ref. 15) identified replacement resistors that would prevent failures. Failures of these resistors have been reported in LERs since 1976.

Certain plants had not implemented specific maintenance instructions written by Terry over 12 years ago, or made turbine assembly reliability enhancements, such as the installation of an oil sump for type EG-R governor actuators proposed by GE in 1976 (see Section 4.2 and footnote 7). Numerous NPRDS failure reports reviewed involved turbine assembly piece-parts addressed in these maintenance instructions (including periodic tests and inspections) promulgated by Terry. These instructions were not available at all plants which reported failures that were reviewed during this study. The failures reviewed indicated that certain plants were not performing these maintenance instructions, including specified periodicities, when the reported failures occurred. These maintenance instructions were in Terry vendor technical information (VTI) issued prior to February 1981, and used at an

INPO-sponsored meeting on standby turbines held that month. Licensee utilization of outdated VTI which does not reflect operational experience does not appear to meet the intent of NRC Generic Letter 83-28 (Ref. 18), which identified inadequate maintenance as a cause of the Salem ATWS events, or NRC Generic letter 90-03 (Ref. 19), which clarified the use of VTI. Three randomly selected plants were contacted during this study concerning the impact of VTI on failures reported in NPRDS with the following results:

- When contacted during this study for data pertaining to a governor failure that occurred in January 1987, one plant indicated that their current Terry VTI was dated 1974. The plant stated that this early VTI did not include the Terry maintenance instruction (monthly verification of the EG-M governor ramp circuit) for the failed piece-part. This maintenance, including periodicity, was in Terry maintenance instructions prior to February 1981, and could have precluded the failure experienced by the plant.
- The second plant contacted during this study reported an inoperable RCIC turbine in January 1987, resulting from a clogged oil inlet orifice. To preclude recurrence, the plant reported that an oil filter was installed, and maintenance initiated to change the oil and clean the oil filter element every refueling outage. This plant stated that it was still using a March 1972 revision of the Terry turbine maintenance instructions which did not address changing turbine lube oil, flushing the system, or maintenance of the oil filter element. Prior to February 1981, Terry added annual maintenance actions to drain the turbine oil, flush the system, and change the oil filter element.
- The third plant contacted during this study stated that their AFW Terry turbines did not have lube oil filters [since these turbines did not have a pressurized system], nor did the Terry turbine maintenance instructions onsite contain preventive maintenance and periodicity requirements. Their Terry manual, dated 1975, specified only procedures for turbine overhaul without indicating a periodicity.

During the NRC Augmented Inspection Team review at the South Texas Project during February 1993 in response to their TDAFWP overspeed events, it was found that the site was using a 1975 Terry manual with a 1978 update and certain other changes. The utility had on site a copy of the EPRI manual on Terry turbine controls, NP-9609, which was uncontrolled and not referenced in any of the applicable site maintenance procedures that were provided to the NRC inspectors. During the AIT inspection, a Woodward governor field representative stated that the as-found adjustment of the Unit 1 governor-valve to governor-servo-mechanism mechanical linkage after the January 28, 1993, overspeed trip was out of adjustment in the direction

²⁵The failures identified in this combined inspection report involved both units and resulted in enforcement action. These failures were not found in NPRDS on June 16, 1993, nor was an LER identified which addressed these failures.

preventing the governor from completely closing, and that this factor alone could result in TDAFWP overspeed during quick-start. A Dresser-Rand (Terry) factory representative stated that the site manuals in use were not adequate by themselves for certain maintenance being performed by the utility.

As discussed in Section 7.4.2, turbine failures have resulted from failures of turbine overspeed-trip mechanisms and governor linkages. Terry-Turbodyne personnel indicated that such linkages were essentially customized for each turbine installation based on the physical configuration of system components. They stated that linkage lubrication is not critical, but that accumulation of dirt and other contaminants on these linkages is critical, as is physical damage. They also indicated that certain linkage-related failures attributed to dirt or lack of lubrication were more probably caused by cumulative damage to the linkage over an extended period of time.

8 CONCLUSIONS

This study confirmed the continuing validity of conclusions of earlier studies by the NRC and by the U.S. nuclear industry that the most significant factors in failures of turbine-driven standby pumps have been the failures of the turbine-drivers and their controls, especially during turbine cold quick-start transients.

The study found that the industry wide demand probability for the turbine-driven Auxiliary Feedwater (AFW) pump was $6.5E-2$ excluding maintenance unavailability, as compared with a value for the Surry Probabilistic Risk Assessment (PRA) in NUREG-1150 of $1.1E-2$ for AFW. Failures were caused primarily by turbine overspeed trips. Estimates of demand probability for PRAs usually include surveillance testing as well as actual demands, with the major contribution being from surveillance testing. Consequently, the demand probability in this study for the AFW turbine-driven pump is higher than plant-specific values used in PRAs.

The study found a demand probability, excluding maintenance unavailability, of $1.9E-2$ for the High Pressure Coolant Injection (HPCI) turbine-driven pump and a demand probability of $1.3E-2$ for Reactor Core Isolation Cooling (RCIC) turbine-driven pump. The demand probability for HPCI and RCIC in NUREG-1150 for Peach Bottom was $3.0E-2$. Failures were due to a turbine overspeed trip and a failed flow controller.

Though NPRDS provided useful information to supplement LER failure data for these standby turbine-driven pumps used for this study, NPRDS was not designed to provide reliability and failure rate data required to perform a rigorous reliability analysis of the turbine drivers

which have been a recurring problem in system reliability, especially on a plant-specific basis.

This study identifies continuing repetitive failures of standby turbine assemblies, especially governor systems. Considering the types of failures identified during this study, enhancement of standby pump turbine-driver reliability could be achieved by 1) the use by plants of existing Terry and Woodward maintenance instructions (which plants contacted during the study did not have) and by plants obtaining additional manufacturer guidance for maintenance not included in existing guidelines, 2) more effective implementation by plants of design control and dedication of commercial grade items used in standby turbine applications, and 3) enhanced use by plants of guidance contained in previously issued NRC and industry generic communications applicable to turbine failures and maintenance (especially those relating to governor and speed control system maintenance, such as EPRI Maintenance Guide NP-6909, and EPRI reports, NSAC 140 and NSAC-150).

In GL 90-03, (Ref. 18), the staff narrowed the scope of the vendor interface program required by GL 83-28, (Ref. 19) which included vendors of all safety-related components, but provided for the program to include (a) NSSS vendors and (b) vendors of other key safety-related components not covered by the NSSS vendor. These requirements may include items that presently may not be covered by the NSSS vendor for purposes of providing the end user with technical information. Reference 18 gave examples of "key" safety-related components whose vendors licensees were expected make a good faith, documented effort to periodically contact. The examples explicitly included auxiliary feedwater pumps. Reference 18 also provided for measures to compensate for those cases when vendors can not or will not provide the desired technical information. Finally, Reference 18 reaffirmed the staff position on the use of vendor technical information defined in Reference 19.

This report documents that improper or inadequate maintenance (some of which resulted from inadequate incorporation of vendor-recommended maintenance practices or inadequate implementation of vendor-recommended modifications or corrective actions) were contributing factors in many of the instances of failure of safety-related standby pump turbine-drivers. Therefore, it appears that a thorough review and updating of the licensee's program for interface with vendors and other sources who could provide relevant technical information for safety-related standby turbine driven pumps, coupled with incorporating such information where applicable in plant procedures, could reduce the number of failures of these turbine-drivers.

The findings of the detailed review of operating experience performed during this study suggest that the results should be useful to NRC staff and licensee personnel in

understanding operational problems and failures of standby turbine-driven pumps. It provides a source of generally unavailable information for utility licensees that want to improve the performance of standby turbine-driven pumps installed in their plants. For this reason, it should be useful in meeting the intent of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," which requires, in part, that industry-wide experience be taken into account, where practical, in establishing criteria for equipment performance and in evaluating the performance of that equipment.

9 REFERENCES

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APPENDIX A

CHARACTERISTICS OF WOODWARD GOVERNORS USED TO CONTROL SAFETY-RELATED STANDBY PUMP TURBINE-DRIVERS AND FACTORS WHICH CAN AFFECT TURBINE-DRIVER RELIABILITY

DRESSER-RAND Terry-Turbodyne (Terry) indicated that Woodward governors have been used for speed control on all Terry turbines used as drivers for AFW, HPCI, and RCIC standby pumps. The Woodward Corporation (Woodward) stated that there are many variations of basic governor types, which provide different speed control characteristics. Governor types, such as EG and PG, are families of customized governors built with a basic speed control design.

NPRDS identified six types of Woodward governors as being installed on Terry turbines used as drivers for AFW system safety-related standby pumps: PG-PL, EG-M, PGA, PGD, PGG, and UG.¹ Type EG-M governors with EGR actuators are used with all HPCI and RCIC turbines, and with certain TDAFWPs. This appendix provides information of the design, installation, and operation of these governors which can affect governor performance and reliability.

Woodward stated that stored governors [and actuators] should be filled with a rust and oxidation inhibiting oil such as Texaco Regal R & O oil.

Woodward stated that governor elastomeric parts are primarily made of Viton fluorocarbon rubber, which is one of the most chemically resistant elastomers available and is recommended by Parker seals for applications involving petroleum oils. End users should determine the effects of specific oil additives contained in the governor oil used by them upon governor elastomeric parts.

In conjunction with TDAFWP testing performed after the NRC Augmented Inspection Team review at the South Texas Project (STP) during February 1993 in response to their TDAFWP overspeed events, a Woodward Governor Company field representative stated that governor [and also EGR actuator] buffer springs should be selected to ensure TDAFWP speed stability for all flow paths and system alignments, and the oscillations such as occurred at STP were a result of a change in the dynamics of TDAFWP operation (flow path, discharge pressure, etc.), which was not considered in the initial selection of the buffer springs.

Certain Woodward governors have been modified by the installation of a "shutdown bellows" to vent the governor's speed setting oil pressure during turbine coastdown from a trip or controlled shutdown. This feature permits immediate turbine restart (without overspeed), which Terry designates a "Time Delay Accumulator & Internal Pressure Shutdown," using a Woodward "pressure actuated shutdown assembly." Figure A-1 is a diagram of a PG-PL governor with this feature installed. By design, a governor oil pump should develop governor oil pressure of 1652.7 to 1825.0 kPa (239.7 to 264.7 lbf/in²), and the shutdown bellows' ball-check valve ["valve seat ball"], shown by the arrow in figure A-1, should reseal when the oil pressure reaches 1204.5 kPa (174.7 lbf/in²). A reported failure of a PG-PL governor system occurred in April 1990 when its shutdown bellows ball-check valve did not reseal. The root cause was that the oil pump discharge pressure was only 1411.4 kPa (204.7 lbf/in²), which was apparently insufficient to reseal the check valve. Lowering the check valve reseal pressure to 790.8 kPa (114.7 lbf/in²) corrected the problem.

Woodward stated that if elastomeric diaphragms [as opposed to bellows] are installed in governor remote speed setting assemblies, they should be replaced every five years.

A Terry factory representative stated that capping a Woodward governor remote speed control bellows air connection when it is not used permits room temperature variations to cause fluctuations in pressure on the bellows that change turbine speed. He stated that, in one case during a post maintenance test, with an initial turbine speed setting of 3600 revolutions per minute (rpm) and the room cool, as the pump room heated up the speed dropped to 3480 rpm. The connection was uncapped and the phenomenon stopped. For reverse acting governors, a pressure increase causes a decrease in turbine speed. For plants having direct acting governors, a pressure increase would cause an increase in turbine speed. A decrease in ambient room temperature could decrease pressure on the bellows (older units may have a diaphragm instead of a bellows) with the opposite affect. Because TDAFWPs are typically subject to changes in temperature, this could be a generic problem affecting TDAFWP operability, including being the root cause of TDAFWP trips whose cause has been identified as "spurious," and "unknown," since temperatures could differ significantly from when a

¹NPRDS engineering records for certain plants did not identify the governor type, nor did they contain a designation that could be identified by Woodward personnel.

turbine speed setting is made and the turbine is cold quick-started.

TYPE PG-PL GOVERNORS.

THESE ARE PG (PRESSURE COMPENSATED) GOVERNORS WITH DIRECT OR REVERSE CONTROL, AND HAVE AN INSTRUMENT AIR (IA) OPERATED SPEED-SETTING MECHANISM FOR REMOTE SPEED CONTROL.

Figure A-2 is a cutaway view, and Figure A-3 is a schematic, of a PG-PL governor. Referenced arrows are for Figures A-2 and A-3. Governor speed change is made by adjusting the manual speed adjusting knob (arrow 1) on the governor itself, or by varying Instrument Air (IA) pressure to the bellows (arrow 2) from a remote location, such as the control room. For direct acting governors (shown in Figure A-3) increasing control air pressure increases speed. For reverse acting governors (see inset, arrow 3) increasing control air pressure decreases speed. Through the use of a governor's hydraulic system, speed settings are translated into turbine speed changes by the linear movement of the power cylinder piston and its shaft (arrow 4), which causes the turbine governor valve to open or close. PG-PL governor features include the buffer springs (arrow 5) and the compensation needle valve (arrow 6) that are required to control unacceptable speed oscillations which can cause turbine overspeed trips.

IA pressure is used for remote governor speed changes, such as from a control room. The IA pressure acting on a diaphragm (or bellows) is used to remotely set a governor's operating speed. When a governor is connected to an IA source, and calibrated to respond to IA pressure changes to change speed settings, loss of IA causes the governor to fail. Woodward stated that IA pressure should be regulated and constant, since variations as small as 3.4 kiloPascals (kPa) (.5 pounds per square inch absolute (lbf/in²)) could affect a turbine's set speed. For reverse acting governors, the loss of IA pressure will cause turbine speed to increase to the overspeed trip set point, if the high speed stops are not properly set. For direct acting governors, the loss of IA pressure will cause turbine speed to decrease to the low speed stop. Woodward indicated that IA quality (purity or moisture content) is not critical to governor operation. NPRDS contains reported Woodward governor failures resulting from the loss of IA pressure to a type PGA governor, and from the failure of a pneumatic transducer [bellows or diaphragm] for a PG-PL governor. Figures A-2 and A-3 show a PG-PL governor and schematic with both of the direct-acting and reverse-acting configurations discussed above. In order to have a full range of speed control using IA, the manual speed adjusting knob (arrow 1) must be at its minimum speed setting (made inactive) for direct acting governors; for reverse acting governors, the manual speed setting

knob (arrow 1) is made inactive by adjusting it to its maximum speed setting. The manual speed setting knob (arrow 1) limits (and overrides) governor speed settings made using IA if the speed adjusting knob is not set as stated above.

TYPE EG-M GOVERNOR SYSTEMS

THESE SYSTEMS ARE ELECTRICAL/ELECTRONIC, CONSISTING OF AN EG-M CONTROL BOX, A RAMP GENERATOR-SIGNAL CONVERTER, AND AN EGR ACTUATOR.

A typical EG-M governor system consists of an EG-M electrical control box [with or without a Ramp Generator/Signal converter], a speed setting potentiometer, a magnetic speed pickup [sensor], which collectively serve the same function as the speed control section of a PG-PL governor (see Figure A-3), and an EGR actuator which serves the same function as the governor valve actuator section of a PG-PL governor (see Figure A-3).

Figure A-4 is a typical Woodward electric governor circuit schematic with a ramp generator/signal converter. The ramp generator controls the governor's rate of response during a quick start. Ramp generators failing, or being out of calibration, have caused a significant number of failures of type EG-M governors used with safety-related standby turbines. A ramp generator functions as a variable capacitor in the governor's DC speed control circuit. Figure A-5 is a typical wiring schematic of an EG-M governor system box using a magnetic [speed] pickup.

An EG-M governor system voltage supply contains a dropping-resistor which reduces battery supply voltage from nominal system "float voltage" of 132 volts direct current (VDC) to 48 VDC used by the EG-M governor system. Failures of this resistor were reported in LERs and in NPRDS failure reports, which are discussed Section 8.4.1 of this report, and in NRC IN 90-51 and its Supplement 1. Failure of this resistor changes an EG-M governor system's reference voltage, making the associated standby turbine inoperable. A speed setting [variable] potentiometer [resistor] in the 48 VDC circuit sets a reference voltage which establishes the speed to which an EG-M governor will control. This reference voltage is an input to the amplifier of EG-M governors. Woodward indicated that a governor reference voltage of 42 volts or less could result in the unacceptable operation of an EG-M governor system [and could have been a cause of turbine failures for which a cause was not determined]. The potentiometer can be motor-operated for remote speed setting.

The other input to the amplifier is a voltage proportional to actual speed. This voltage is generated by a voltage pulse [speed signal] pick-up mounted near a gear on the turbine whose speed is being controlled. Voltage pulses

Figure A-2 Cutaway View of PG-PL Governor

Courtesy of
Woodward Governor Company

Figure A-3 Schematic Diagram of PG-PL Governor

Courtesy of
Woodward Governor Company

Figure A-4 System Drawing

Courtesy of
Woodward Governor Company

Figure A-5 Typical Wiring Diagram for Magnetic Pickup Speed Signal, 48 Vdc Supply

Courtesy of
Woodward Governor Company

are generated by a gear tooth rotating past the pick-up coil.² This voltage is compared to the reference voltage. Voltage differences between the reference voltage and the speed signal voltage cause the governor to send a signal which energizes an electro-hydraulic transducer in the associated EG-R actuator. The actuator output then opens or closes the turbine's governor valve, adjusting the turbine speed.

Woodward literature states that their electronic controls are not directly grounded, but in many cases the negative (-) power supply (or common) is tied to ground through the battery used as a power supply. Should an additional device also be grounded or powered by the same grounded-battery system, a short circuit is possible.

On type EG-M electric governor systems used on HPCI, RCIC, and on certain AFW turbines, initiation of the ramp generator circuit is from the "valve closed" limit switch on the turbine steam supply (stop) valve when the valve's disc starts to leave the seat (or on the trip and throttle valve when it functions as the turbine steam stop valve for certain AFW installations).

Woodward Governor Company technical information as early as 1981 identified that EG-M control units were optionally supplied with encapsulated circuit boards for environmental protection. Most plant designs, and governor procurement, predate 1981. This study did not review the use of replacement circuit boards of different designs for safety-related applications or their effect on governor reliability.

The Woodward company indicated that, for at least five years, new and replacement unencapsulated circuit boards have been supplied with a "conformed silicon coating." The effects of this design change on safety-related EG-M governor systems (from a possible negative effect of increased operating temperature and potentially reduced piece-part life, to possibly improved reliability and life during normal plant operations because of moisture exclusion), was not reviewed during this study.

EG-M governor systems are ungrounded. According to Woodward instructions, grounding more than one point in a circuit during electrical checks can cause damage to the circuit. The Woodward Company indicated that consideration of the effects of ground faults on an ungrounded direct current (DC) EG-M governor system, including external wiring, is a function of the application design engineering organization. The Woodward Company indicated that external wiring for EG-M governor systems, including EGR actuators, should be shielded stranded wire

²Dimensions and tolerances related to magnetic pickup (MPU) installations are critical, and in some cases as small as 0.005 of an inch. Instructions for the installation, and troubleshooting of MPUs is detailed in Woodward publication 82510L, "Magnetic Pickups and Proximity Switches for Electric Governors."

of at least 22 American Wire Gage (AWG), with the shielding properly grounded to prevent spurious external signals from affecting the operation of the EG-M governor systems. Use of improperly sized, unshielded, or partially grounded, external governor wiring could be a cause of reported EG-M governor speed control failures for which no cause was determined. Improper grounding of the system or components, including during tests and calibration can damage components and the system.

GE stated that the null voltage polarity for EG-M control boxes, and the null voltage screw on EG-R actuators, are specifically set to fail to "shutdown" on the HPCI turbine, and to fail to "overspeed" on the RCIC turbine upon "loss of signal."

EGR ACTUATORS

Figure A-6 is a front and rear view of an EGR (EG) actuator. Figure A-7 is a schematic diagram of this EGR actuator. The actuator has its own oil pump and functionally duplicates the actuator section of a PG-PL governor (see Figure A-3). Figure A-7, arrow 1, shows the electrical coil by which the EG-M control box electrical signal causes an EGR actuator to move. Electrical and mechanical failures of EGR actuators have been reported in LERs and NPRDS failure reports since 1977. The EGR actuator has buffer springs (figure A-7, arrow 2) and a [compensation] needle valve (figure A-7, arrow 3) which are functionally identical to those of a type PG governor.

There are two types of EG actuators, proportional and integrating. Proportional actuators have a "P" suffix and integrating actuators have a "C" suffix.³ Proportional actuators go to the minimum speed setting upon loss of power. Integrating actuators can be calibrated to go to the maximum or minimum setting upon loss of signal, i.e., they can either shut a turbine down or allow it to overspeed on loss of signal.

Based on Woodward data, all EG actuators for a standby pump turbine-drivers should fail high upon loss of signal, since actuators that fail low must be manually overridden before a turbine would start.

EG actuators are designed to operate ungrounded. If an actuator's leads are shorted to ground, the actuator would see a loss of signal.

Woodward stated that actuators are capable of drawing 12 inches of head through 1/4 inch tubing. For actuators which use turbine lube oil as their hydraulic fluid, this fact and the need for clean oil of the proper viscosity should be considered.

³GE stated that HPCI and RCIC turbine governors use integrating actuators that have neither a "P" or "C" suffix.

Figure A-6 EGR Actuator

*Courtesy of
Woodward Governor Company*

Figure A-7 Schematic Diagram of EG-3C Actuator

Courtesy of
Woodward Governor Company

TYPE PGA GOVERNORS.

THESE ARE SIMILAR TO PG-PL GOVERNORS WHICH HAVE A PNEUMATIC REMOTE SPEED SETTING CAPABILITY, BUT THESE GOVERNORS ALSO HAVE A LONG COLUMN TO HOUSE VARIOUS LOAD CONTROL OPTIONS.

The physical arrangement of a PGA governor is similar to that of a PG-PL governor. Figure A-8 shows a schematic of this governor. For standby turbine applications (which do not utilize the speed droop feature) these governors function in the same manner as PG-PL governors. Remote operation of these governors using instrument air (IA) is as described above for type PG-PL governors.

TYPE PGD GOVERNORS.

THESE ARE BASIC PG [PRESSURE COMPENSATED] MECHANICAL HYDRAULIC GOVERNORS WITH A DIAL TYPE SPEED SETTING, BUT WITHOUT A SPEED-RAMP FEATURE TO CONTROL TURBINE OVERSPEED DURING QUICK-STARTS.

Figure A-9 is an exterior view of a PGD governor. Figure A-10 is a diagram of typical PG governor, while figure A-11 is a schematic diagram of the dial arrangement for a PGD governor. The operation and failure modes are similar to those of a PG-PL governor, except that this governor does not have a speed-ramp feature for quick-starts, or a feature to permit remote governor speed control using IA. Certain NPRDS failure reports in 1990 reported replacing PGD governors with "upgraded governors."

TYPE PGG GOVERNORS.

THESE ARE PG GOVERNORS WITH A SPEED SETTING MOTOR FOR REMOTE SPEED SETTING,

AND WITH MANUAL DROOP ADJUSTMENT AND LOAD LIMIT CONTROL FEATURES. THE SPECIAL FEATURES OF THESE GOVERNORS, SUCH AS DROOP CONTROL AND LOAD LIMIT CONTROL, ARE FOR THE CONTROL OF DRIVERS USED WITH ELECTRICAL GENERATORS, ESPECIALLY GENERATORS ELECTRICALLY CONNECTED IN PARALLEL AND LOAD SHARING.

Type PGG governors have been installed as replacements for certain safety-related standby turbines applications. Functionally these governors are like PG-PL governors, except for speed setting. The schematic diagram for the remote speed setting function using a motor (instead of IA and a bellows assembly used for PG governors) is figure A-12. The speed setting motor is identified by the arrow. Except for failure of IA, all PG-PL failure modes apply.

TYPE UG GOVERNORS.

THESE ARE MECHANICAL/HYDRAULIC DIAL AND LEVER GOVERNORS WITHOUT A SPEED-RAMP TURBINE OVERSPEED CONTROL FEATURE OR BUFFER PISTONS TO REDUCE TURBINE OVERSPEED TRIPS DURING QUICK-STARTS.

One safety-related standby turbine application using this type governor was identified. This governor type is primarily designed for speed control of medium diesel engines according to Woodward. The lever version of a UG governor is shown in figure A-13. Neither the dial nor lever model has buffer pistons for controlling speed stability during quick-starts. The dial model has a speed setting motor for remote speed control similar to the PGG governors.

Figure A-8 Schematic Diagram of PGA with Direct Belows

Figure A-9 PG Governor Dial Type Speed Setting

*Courtesy of
Woodward Governor Company*

Figure A-10

Courtesy of
Woodward Governor Company

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Figure A-11 Schematic Diagram, PG Dial Speed Setting

Courtesy of
Woodward Governor Company

Figure A-12 Speed Setting Schematic

Courtesy of
Woodward Governor Company

APPENDIX B

DEMAND RELIABILITY OF STANDBY TURBINE-DRIVEN PUMPS

A. Turbine-Driven Auxiliary Feed Water Pump (TDAFWP) Reliability

1. The determination of valid demands for standby turbine-driven Auxiliary Feedwater pumps (TDAFWPs) [including Emergency Feedwater pumps] required in-depth review and analysis. Such actuations were frequently not specifically documented in LERs which typically stated that "...the AFW system functioned as designed..." A review was made of the latest PWR USARs to determine the actuation logic for TDAFWPs. The following twenty-three TDAFWP initiation signals were identified. As many as five different initiation signals were applicable at certain plants:

- Trip or loss of main feedwater pumps¹
- Low-Low level in two or more steam generators¹
- Low steam generator level
- Loss of Off-site power signal
- Loss of Off-site power¹
- Emergency Safety Feature (ESF) actuation
- Emergency Safety Feature (ESF) actuation signal
- Anticipated Transient Without Scram Mitigation System Actuation Circuitry (AMSAC) signal²
- Emergency Feedwater Actuation System (EFAS) signal (including Palo Verde AFAS)³
- Safety Injection¹
- Safety Injection signal
- RPS anticipatory trip
- Feedwater line break¹
- Loss of all Reactor Coolant Pumps (RCPs)
- High containment pressure

¹May result in, may be coincident with, or may be caused by a reactor trip.

²AMSAC actuates AFW based on loss of main feedwater (MFW) flow in three-out-of-four MFW lines, with a turbine-load-based time delay.

³The signals are low steam generator level and steam generator differential pressure.

- Low pressure in either steam generator
- Emergency Feedwater Initiation and Control (EFIC) system⁴
- Steam and Feedwater Line Rupture Control System (SFRCS)⁵
- 4KV/RCP bus undervoltage or voltage loss
- Undervoltage on diesel generator buses
- Loss of two 480 volt buses and a reactor trip
- Undervoltage on 480 volt motor control centers (MCCs)
- Loss of preferred station power

In addition to the initiation signals listed above, unique TDAFWP initiation methodologies were identified during the study for the following nine plants:

- For Millstone 2, the USAR indicated that the TDAFW pump must be initiated manually.
- For Yankee Rowe, the USAR stated that the TDAFWP must be operated locally in the auxiliary boiler room.
- For Maine Yankee, the USAR stated that only the MDAFWPs automatically start. The TDAFWP can be manually started from the control room.
- For Indian Point 2, the USAR stated that the TDAFWP turbine speed is set to minimum (by a remote pneumatic speed controller). Upon the generation of an automatic turbine quick-start signal, the turbine starts and accelerates to its slow-speed setting, with the pump discharge set to recirculation flow. Aligning TDAFWP discharge flow to the steam

⁴The EFIC system automatically starts the TDAFWP based on any of the following conditions:

- Both MFPs trip and reactor power is > 20%.
- Low level in either steam generator.
- Low pressure in either steam generator.
- All 4 RCPs trip.
- High pressure injection (HPI) on both A and B ESAS channels.

⁵The SFRCS system automatically starts the AFW system pumps based on the following signals:

- Loss of both MFW pumps
- Loss of all 4 RCPs
- Main steam line rupture
- MFW line rupture

generators requires manual operator action. Indian Point 3 uses the same TDAFWP actuation method.

- For San Onofre 1, the USAR indicated that upon receipt of a steam generator low level signal, the TDAFWP starts and enters a warm-up mode. (LER 05000206/89-012 amplified the USAR description for those cases where the train containing the TDAFWP actuates, but the other train does not indicate flow.)
- For St Lucie 1, the USAR stated that the TDAFWP start circuit has a time delay after the receipt of a steam generator low level signal. If the signal clears during the delay, the TDAFWP does not start.
- For St. Lucie 2, the USAR indicated that after receipt of an automatic initiation signal, there is a 305 second time delay. If the initiating signal clears during this delay, the TDAFWP does not start.
- At Turkey Point 3 and 4, the TDAFWPs did not quick-start. Each of the 3 TDAFWPs is rated at 600 gpm at a turbine speed of 5900 rpm, but each TDAFWP is set to discharge 130 GPM (which would be a turbine speed of 1278 rpm based on the affinity laws). At this speed, the turbines are essentially operating on their slow speed stop. All 3 TDAFWPs line up on, and inject to, the affected unit. Operators adjust TDAFWP flow after start as required.
- Haddam Neck is unique in that the pressure of the steam to the turbine is 4238 Kpa (614.7 lbf/ft²) and the TDAFWP uses a Woodward model 501 electronic governor.

Searches of the Sequence Coding and Search System (SCSS) LER database identified LERs of events from January 1, 1987, through December 31, 1992, such as reactor trips and ESF actuations, which could result in TDAFWP demand starts. The resultant list of 934 LERs was analyzed using the plantspecific TDAFWP initiation parameters. Each plant was reviewed in the light of all LERs analyzed for that plant. For example, one LER for a plant might describe in detail a reactor trip from 100% power and state that the two (100% capacity) MDAFWPs actuated and recovered steam generator levels without actuation of the TDAFWP. If another LER for the same plant chronicled a similar event, but stated that the AFW system responded as designed, then it was assumed that the TDAFWP did not receive a demand. In the latter case, the full text of the LER would be reviewed to assure that there was no mention of the TDAFWP. Certain LER texts identified that following a trip from 100% thermal power, the MDAFWPs were adequate to maintain SG levels without actuating the plant's TDAFWP. Some plants

have MDAFWPs which can each supply 50% of required flow; others have MDAFW pumps that each can supply 100% of required flow. A TDAFWP can supply 100% of required flow. Certain LERs identify that following a reactor trip (especially at lower power), the TDAFWP was not needed and was secured immediately after its demand start, which could preclude a TDAFWP overspeed trip. Securing the TDAFWP apparently is done typically to prevent excessive post-trip reactor cooldown, since 2 MDAFWPs provide 100%-200% of AFW requirements. LERs which indicated TDAFWP demand failures are bolded. Table 1 contains a listing of TDAFWP demand failures with a characterization of each failure.

244/88-005;	244/89-004;	244/92-002;	251/91-006;
255/91-012;	255/92-034;	255/92-038;	255/92-039;
261/92-017;	266/91-008;	266/92-008;	275/91-002;
275/91-007;	275/92-002;	275/92-004;	280/88-003;
280/90-004;	281/88-010;	281/89-010;	281/90-003;
281/90-004;	281/92-010;	286/92-015;	287/92-001;
287/92-003;	289/91-007;	289/91-003;	289/92-001;
295/90-020;	295/91-016;	301/87-002;	301/91-006;
302/88-001;	302/88-002;	302/88-006;	302/89-023;
302/91-003;	302/91-014;	302/91-016;	302/91-018;
302/92-001;	302/92-015;	302/92-027;	304/87-007;
305/91-010;	305/92-017;	311/91-017;	311/92-014;
312/88-015;	312/88-019;	313/87-003;	313/87-004;
313/87-005;	313/89-048;	313/91-001;	313/91-003;
313/91-005;	315/87-008;	315/87-021;	315/89-001;
315/91-004;	316/87-004;	316/87-007;	316/87-008;
316/90-012;	316/90-013;	316/91-004;	316/91-006;
317/91-003;	317/92-008;	318/87-002;	318/87-006;
318/87-007;	318/87-008;	318/92-001;	318/92-003;
318/92-006;	318/92-007;	327/88-045;	327/88-047;
327/90-030;	328/88-027;	328/88-028;	334/88-014;
334/92-009;	335/87-013;	335/87-017;	335/88-003;
335/88-008;	335/91-002;	336/87-012;	338/87-012;
338/87-020;	338/88-002;	338/88-005;	338/88-020;
338/89-005;	339/88-001;	339/91-009;	339/92-001;
339/92-007;	344/87-001;	344/87-024;	344/87-037;
344/88-026;	344/88-028;	344/89-017;	344/90-033;
344/90-034;	344/91-004;	344/92-014;	344/92-020;
344/92-027;	344/92-028;	346/87-001;	346/87-006;
346/87-011;	348/91-006;	348/91-007;	348/91-008;
348/91-009;	348/91-010;	348/92-008;	361/87-001;
361/87-004;	361/88-002;	361/91-007;	361/92-012;
362/91-001;	362/92-003;	362/92-004;	364/91-002;
364/91-005;	364/92-001;	364/92-002;	364/92-005;
364/92-006;	364/92-007;	364/92-008;	364/92-010;
368/87-007;	368/87-008;	368/88-011;	368/88-020;
368/89-006;	368/89-008;	368/89-024;	368/90-019;
368/90-020;	368/91-005;	369/87-009;	369/89-025;
369/91-001;	369/92-008;	370/89-002;	382/87-020;
382/88-033;	382/89-013;	382/89-024;	382/90-003;
382/90-004;	382/91-013;	382/91-022;	389/87-003;
389/89-007;	389/90-001;	389/92-004;	389/92-005;

389/92-006; 395/87-015; 395/87-027; 395/88-002;
 395/88-006; 395/88-007; 400/87-008; 400/87-017;
 400/87-025; **400/87-035**; **400/89-001**; 400/89-005;
400/89-006; **400/89-017**; 400/92-010; 412/87-020;
 412/87-023; 412/87-026; 412/87-032; 412/89-003;
 412/89-019; **412/90-008**; 412/91-005; 414/87-010;
 414/87-018; 414/87-019; 414/87-025; 414/87-027;
414/87-029; 414/88-012; 414/88-023; 414/88-024;
 414/88-025; 414/89-001; 414/89-002; 414/89-003;
 414/90-013; 414/91-008; 423/87-026; 423/87-031;
 424/87-025; 424/87-030; 424/87-041; 424/87-050;
 424/87-063; 424/87-066; 424/88-001; 424/88-008;
 424/88-013; 424/88-024; **424/89-005**; 424/90-016;
 424/90-023; 424/91-002; 425/89-020; 425/89-023;
 425/89-024; 425/89-029; 425/89-031; 425/90-002;
 425/90-007; 425/91-005; 425/91-006; 425/91-007;
 425/92-002; 425/92-008; 425/92-010; 443/91-002;
 443/91-008; 443/91-009; 443/92-017; 443/92-025;
 445/90-013; 445/90-017; 445/90-027; 445/91-002;
 445/91-008; 445/91-019; 445/91-021; 445/91-022;
 445/91-023; 483/87-022; 482/87-027; 482/87-030;
 482/87-037; 482/87-041; 482/89-002; 482/89-004;
 482/90-001; 482/90-013; 482/90-014; 482/90-023;
 482/91-006; 482/92-016; 483/88-004; 483/88-006;
 483/88-007; 483/88-010; 483/89-006; 483/90-005;
 483/90-007; 483/90-016; 483/90-017; 483/92-002;
 483/92-010; 498/89-001; 498/90-020; 498/91-012;
 498/91-013; 498/91-021; 498/91-022; 498/92-003;
499/89-013; 499/91-001; 499/91-003; 499/91-004;
 499/91-009; 499/91-010; 499/92-001; 499/92-003;
 499/92-010; 528/91-010; 659/87-010; 663/89-003.

B. High Pressure Coolant Injection (HPCI) and Reactor Coolant Isolation Cooling (RCIC) Turbine-Driven Pump (TDP) Reliability

Significant factors in HPCI and RCIC pump turbine-driver reliability during the period of time covered by this study were apparently 1) the plant-specific implementation of applicable GE SILs, 2) accomplishment of maintenance proposed by INPO in 1981, and 3) the accomplish-

ment of applicable Terry-Turbodyne and Woodward Governor Company suggested maintenance practices based on operational feedback. The specific relationship between these factors and demand reliability represented by the LERs analyzed was beyond the scope of this study. The SCSS database was searched for LERs of events from January 1, 1987, through December 31, 1992, such as reactor trips and ESF actuations, which could result in HPCI and RCIC TDP demand starts. The resultant 423 LERs used as the basis for determining demand starts for HPCI and RCIC pump turbine reliability are as follows (only the three unique digits of docket numbers are shown with the LERs). LERs which indicated HPCI and RCIC TDP demand failures are bolded. Table 2 contains a listing of HPCI and RCIC demand failures with a characterization of each failure.

263/87-009; 263/91-019; 271/91-009; 277/89-033;
 277/92-010;⁶ 277/92-012;⁶ 278/92-008; 287/91-008;
 298/87-009; 298/87-011; 298/88-021; 298/89-026;
 298/90-011; **321/87-011**; 321/87-013; 321/88-013;
 321/90-013; **321/91-001**; 321/91-007⁷; 321/91-017⁶;
 321/92-021; 321/92-024⁶; 324/87-011; 324/87-004;
 324/88-018; 324/89-009; 324/90-008; 324/90-009;
 324/90-015; 324/91-001⁷; 324/91-021⁷; 324/92-001⁶;
 325/91-018; 325/92-003⁶; 325/92-005⁶; **331/89-003**;
 331/89-008; 331/89-011⁷; **333/89-020**; 333/90-009;
 341/92-012; 352/87-048; 353/90-015⁶; 354/87-017;
 354/87-034; 354/87-037; 354/87-039; 354/88-022⁷;
 354/88-027; 354/88-029; 366/87-003; 366/87-006;
 366/87-008; 366/87-009; 366/88-017; 366/88-020;
 366/89-005; 366/90-001⁷; 366/92-009; 373/92/003⁶;
 373/92-008⁶; 374/92-012⁶; 374/92-013⁶; 387/87-013⁶;
 388/87-006; 397/87-002; 410/88-001⁸; 410/88-0128;
 410/88-014⁸; 410/89-014⁸; 410/91-017; 410/91-023;
 416/89-010⁸; 416/92-013⁸; 440/87-064⁸; 440/87-072⁸;
 440/90-001⁸; 440/92-017⁸; 458/88-018⁸; 458/88-021⁸;
 458/89-008⁸; **416/89-016⁸**.

⁶HPCI did not receive a demand, only RCIC.

⁷There was no RCIC demand, only HPCI.

⁸This plant has HPCS, not HPCI.

Table B-1. Auxiliary Feedwater Turbine-Driven Pump Failure Characterization from LERs

LER Number	Characterization of Failures
50-302/88-002	The TDAFWP tripped from Condensate buildup in its steam inlet line, resulting from the steam inlet bypass line throttling valve being opened insufficiently.
50-336/87-012	The TDAFWP failed to start because the control panel "Reset/Override" switch was in an intermediate position, preventing a permissive signal to start.
50-338/88-002	The TDAFWP tripped. The cause was a blown plug in the stroke limiter/regulator valve, which affected the trip valve linkage causing the trip valve to shut. The stroke limiter/regulator valve was deleted from the system.
50-316/91-004	Electronic overspeed trip of the TDAFWP turbine.
50-316/91-006	Electronic overspeed trip of the TDAFWP turbine.
50-317/92-008	Bearing failure requiring the TDAFWP to be secured.
50-344/87-037	The TDAFWP failed to start because of a loose electrical connection in its auto-start circuitry.
50-368/89-006	The TDAFWP tripped on overspeed caused by a drift in the setting of its governor's speed ramp generator from the specified 15 seconds to 3 seconds.
50-368/89-008	The TDAFWP tripped on overspeed due to the failure of the governor's ramp generator. The LER reported a second overspeed trip during troubleshooting caused by the failure of the governor's EG-M control box.
50-369/87-009	The TDAFWP was out-of-service and not available.
50-382/87-020	The TDAFWP tripped on overspeed caused by improper latching of the mechanical overspeed trip mechanism.
50-389/87-003	The TDAFWP tripped on overspeed. The root cause of the trip was not identified.
50-389/90-001	The TDAFWP tripped on overspeed. The root cause was contaminated governor oil.
50-400/87-035	The TDAFWP tripped on overspeed caused by condensate in its steam supply line.
50-400/89-001	The TDAFWP tripped on overspeed caused by condensate in its steam supply line.
50-400/89-006	The TDAFWP was out-of-service and not available.
50-400/89-017	The TDAFWP tripped because of a spurious signal from turbine electrical trip unit.
50-412/90-008	The TDAFWP tripped on overspeed caused by the adjustment of the governor valve linkage.
50-414/87-029	The TDAFWP tripped on overspeed. The root cause was contaminated governor oil.
50-424/89-005	The TDAFWP tripped on overspeed. The presumed cause was contaminated governor oil.
50-499/89-013	When restarted after being secured, the TDAFWP tripped on overspeed. The root cause was that the turbine was still rolling and the governor oil pressure had not dropped to zero, causing the governor valve to open too rapidly during restart.

Table B-2. RCIC and HPCI Pump Failure Characterization from LERs

LER Number	Characterization of Failures
50-321/87-011	RCIC turbine-driven pump tripped on overspeed. The root cause was a component failure in the electronic governor's magnetic speed pick-up module.
50-321/91-001	HPCI flow control failed.
50-331/89-003	The RCIC turbine-driven pump was out-of-service and was not available.
50-333/89-020	The HPCI turbine-driven pump was out-of-service and not available.
50-416/89-016	The RCIC turbine-driven pump was unavailable because of maintenance.

APPENDIX C

EXAMPLES SUPPORTING REPORT SECTIONS 7.4.1, 7.4.3, & 7.7

Example 1—Examples Of Governor Calibration Anomalies Causing Turbine Failures

The eighteen LERs reviewed during the study which addressed governor calibration anomalies and associated turbine failures included LERs 05000259/77-021; 05000277/78-009; 05000298/78-011; 05000321/79-017; 05000325/79-001; 05000296/79-026; 05000366/83-069/03X-1; 05000387/83-106/03L-0; 05000331/85-028-00; 05000325/82-025/03L-0; 05000327/81-045/03L-0; 05000327/81-062/03L-0 05000327/83-005/03L-0; 05000331/88-004-00; 05000366/83-055/03L-0; 05000368/83-012/03L-0; 05000278/81-016/03L-0; 05000348/80-017/03L-0. NPRDS also contained failures related to governor calibration anomalies.

Example 2—Examples Of Governor Ramp Generator Failures Causing Turbine Failures

The twenty-eight LERs reviewed during the study which addressed failures of Woodward type EG-M governor system ramp-generator electronic modules included LERs 05000260/76-013; 05000259/77-022; 05000296/77-015/03L-0; 05000278/76-052/03L-0; 05000277/76-054/03L-0; 05000277/80-026/01T-0; 05000277/87-020-01; 05000277/83-018/03L-0; 05000293/80-085/03L-0; 05000321/90-001-00; 05000324/81-039/03L-0; 05000263/83-002/03L; 05000324/79-055; 05000366/79-096; 05000321/85-016-00; 05000321-052/03L-0; 05000271/82-019/03L; 05000293/89-028-00; 05000335/82-046/03L-0; 05000366/83-082/03L-0; 05000321/83-122/03L-0; 05000416/83-151/03L-0; 05000298/84-004-00; 05000325/82-007/03L-0; 05000278/90-001-00; 05000368/89-008-00; 05000296/80-014/03L-0; 05000296/80-021/03L-0. NPRDS also contained failures of ramp-generator modules.

Example 3—Examples Of Lubrication Problems Causing Turbine Failures

The eight LERs reviewed during the study which addressed standby turbine lubrication system problems and turbine failures included LERs 05000244/75-001; 05000331/77-077; 05000333/77-017; 05000263/79-016; 05000321/83-093/03L-0; 05000341/87-006-00; 05000287/80-018-03L-0; 05000287/83-003/03L-0. During the time period covered by this study, NPRDS reported failures of RCIC turbines from dirty oil filters, but no turbine bearing failures. Conversely, NPRDS reported AFW turbine bearing failures, but no clogged filters. Typically, AFW turbines have "splash-type" lubrication sys-

tems using "slinger rings," where RCIC turbines have shaft lube-oil pumps. Slinger-ring lubrication systems do not have oil filters. The lack of oil filters could be the cause of more numerous AFW turbine bearing failures from contaminated oil.

Example 4—Examples Of Maintenance Related Turbine Failures

The twelve LERs reviewed during this study which addressed other maintenancerelated turbine failures included LERs 05000324/77-071; 05000331/77-096; 05000331/78-025; 05000324/79-008; 05000325/79-089; 05000280/82-066/03L-0; 05000293/83-039/03L-0; 05000354/86-082-00; 05000366/81-086/03L-0; 05000315/84-004-00; 05000346/81-040/03L-0; 05000346/81-045/03L-0. NPRDS contained examples of failures in these general areas.

Example 5—Examples Of Lack Of Adherence To Vendor Specified Maintenance Discussed In Report Section 7.7

Periodicities for specified preventive maintenance actions have been increased over those recommended by manufacturers, based on the absence of plantspecific failure history and a desire to not put safety-related equipment out-of-service during plant operation. As fuel cycles are extended, preventive maintenance periodicities could increase even more.

As an example, the following preventive maintenance actions which could affect turbine reliability were supplied to a plant with recommended periodicities as shown in parentheses. Actual maintenance was scheduled for refueling outages to reduce turbine unavailability.

- Verify proper spring tensions and operation of the governor valve assembly and emergency trip mechanism (quarterly).
- Verify proper governor valve stroke (quarterly).
- Verify governor valve calibration (quarterly).
- Check freedom-of-movement of all linkages (quarterly).
- Calibrate pressure switches and temperature switches (quarterly).
- Replace oil filter elements (annual). [Factory recommended maintenance now consists of performing a