NRC FORM 366 U.S. NUCLEAR REGULATORY COMMISSION

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ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS MANDATORY INFORMATION COLLECTION REQUEST: 50.0 HRS. REPORTED LESSONS LEARNED ARE INCORPORATED INTO THE LICENSING PROCESS AND FED BACK TO INDUSTRY. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (T-6 F33), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
McGuire Nuclear Station, Unit 2	05000 370	1 of 10

TITLE (4)
Failure to comply with the operability requirements and required actions of Technical Specification 3.7.4., Steam Generator Power Operated Relief Valves and former Selected Licensee Commitment 16.10.1.

EVENT DATE (5)			LER NUMBER (6)					REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR		SEQUENTIAL NUMBER		REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER(S) 05000
05	04	99	99	-	01	-	0	06	03	99	McGuire Unit 2	05000 370

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR (Check one or more of the following) (11)			
POWER LEVEL (10)	100 %	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	X OTHER - Selected Licensee Commitment *Abstract below and in Text*
		20.405(a)(1)(iii)	X 50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
J. W. Bryant	(704)	875-4162

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS *	
B1a	SA	RV	D263, C600	EPIX Reportable							

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e. approximately fifteen single-space typewritten lines) (16)

Unit Status: Unit 1 and Unit 2 were in Mode 1 (Power Operation) at 100 percent power.

Event Description: McGuire Technical Specification 3.7.4 requires three Steam Generator Power Operated Relief Valves be operable in Modes 1-3 and in Mode 4 when Steam Generators are relied on for cooldown. The BASES for Technical Specification 3.7.4 indicates that a relief valve is operable when it is capable of fully opening and closing using its handwheel. On 5/4/99, it was discovered that the manual operation of two Unit 2 relief valves was probably impaired for some period of time from 12/13/97 to 3/14/99 due to loose actuator manual override shaft keys. During this period, Unit 2 was in plant Modes where Technical Specification 3.7.4 was applicable. Therefore, it is conservatively assumed that the relief valves were inoperable for a period of time exceeding the action completion time of Technical Specification 3.7.4. This represented a Technical Specification prohibited condition. This assumed condition was also prohibited by former Selected Licensee Commitment 16.10.1.

Event Cause: Design misapplication allowed actuator manual override shaft keys on the affected relief valves to loosen and impair manual operation.

Corrective Action: Manual override shaft keys were reinstalled upon discovery and peened to prevent them from loosening. Actuators will be modified to provide a more positive means of retaining the keys in position. Periodic maintenance will be developed to inspect the keys for proper installation. McGuire accident analysis and Technical Specification BASES inconsistencies will be resolved as needed.

ilures will be reported through EPIX

EVALUATION:

At the time of discovery. Unit 1 and Unit 2 were in Mode 1 (Power Operation) at 100 percent power.

Background

Unit 2 Steam Generator (SG) Power Operated Relief Valves (PORV) 2SV1, 2SV7, 2SV13, and 2SV19 are located upstream of the main steam isolation valve for the respective SG served by each relief valve. The UFSAR accident analyses credit manual operation of these valves to provide cooldown during a Steam Generator Tube Rupture (SGTR) event. Technical Specifications (TS) specify the number of operable SG PORVs needed to ensure sufficient cooldown capacity. On 5/4/99, it was discovered that McGuire Unit 2 may have failed to comply with the TS requirements related to the number of operable SG PORVs. This event was initially reported as an unanalyzed condition significantly compromising plant safety in accordance with the requirements of 10 CFR 50.72(b)(1)(ii)(A). However, upon further review it was determined that the circumstances of this event did not warrant reporting under that criteria. Instead it is being reported as a TS prohibited condition in accordance with the requirements of 10 CFR 50.73(a)(2)(i)(B).

The McGuire SGTR accident analysis contained in Section 15.6.3 of the McGuire UFSAR takes credit for manual operation of the SG PORVs in mitigating the effects and consequences of a SGTR event. During this event, the analysis assumes a loss of offsite power (LOOP) and that the PORV on the affected SG fails to close, requiring local operator action to close the respective PORV block valve. Upon isolation of this PORV, RCS and SG pressures slowly rise back to their nominal post-trip values. Cooldown is required to reduce RCS temperature to the target subcooled temperature, allowing RCS pressure to be lowered to that of the ruptured SG. This depressurization of the RCS eliminates the driving force for breakflow. However, as a result of the LOOP, the condenser steam dump valves automatically close and they are unavailable to perform this cooldown function. Consequently, operators begin cooling down the unit using the SG PORVs on the unaffected SGs. Since the motive force for remote operation of these PORVs (instrument air) is unavailable due to the LOOP, manual operation of the PORVs is directed by procedure using the local actuator handwheels. Once initiated, cooldown continues until the target subcooled temperature is reached at which time the RCS is depressurized to stop break flow. Note that the UFSAR SGTR accident analysis assumes that two SG PORVs on unaffected SGs are needed to cool

the RCS to the subcooled target temperature in the timeframes needed to support the offsite dose conclusions.

McGuire TS 3.7.4 requires that three SG PORVs be operable in Modes 1,2, and 3 and in Mode 4 when the SGs are relied on for cooldown. This TS was implemented as part of the Standardized Technical Specifications (STS) at McGuire on 11/14/98. The BASES for TS 3.7.4 states that three operable SG PORVs are needed to ensure that at least one PORV is available to conduct a unit cooldown following a SGTR in which the ruptured SG is not available accompanied by a single active failure of a PORV on an unaffected SG. The BASES for TS 3.7.4 also indicate that a PORV is operable when it is capable of fully opening and closing using the handwheel on its actuator.

Note that the UFSAR SGTR accident analysis and the TS 3.7.4 BASES provide different assumptions and conclusions related to PORV failures and the number of PORVs required for adequate cooling. The accident analysis assumes a failure of the PORV on the SG with the rupture and assumes that two PORVs on unaffected SGs are needed to provide the required subcooling of the RCS. The TS BASES assume an additional failure of a PORV on an unaffected SG and indicates that only one PORV on an unaffected SG is needed to provide adequate cooling. This apparent inconsistency will be evaluated as part of the corrective actions associated with this report. However, since TS 3.7.4 requires three operable SG PORVs, sufficient capacity is available to ensure that both the accident analysis and TS BASES conclusions related to the number of required PORVs is satisfied.

Description of Event

TS surveillance 3.7.4.1 verifies PORV operability by manually opening and closing each valve every 18 months. The test procedure was first performed on the Unit 2 SG PORVs on 12/13/97. No problems were observed with the manual operation of the Unit 2 PORVs during that test. The next performance of this test procedure occurred on 3/14/99 during Mode 5 of the Unit 2 End of Cycle 12 (EOC12) refueling outage. During that test, plant personnel were unable to cycle SG PORVs 2SV1 and 2SV7 using the respective valve actuator handwheels. The dust cover which protects the manual override shaft on each valve was removed. Inspection of the internals determined that the key, which engages the manual override shaft to the stationary operator shell cap, was loose. Plant personnel reinstalled the keys in the actuators for 2SV1 and 2SV7 and completed testing by successfully cycling each valve.

During the evaluation of this problem, plant engineering staff observed the cycling of 2SV1 and 2SV7. Given that 2SV1 and 2SV7 cycled satisfactory and that the engineering staff were unaware the loose keys had been found and reinstalled during the 3/14/99 testing, it was concluded that the original problem identified with 2SV1 and 2SV7 did not affect the operability of these valves. However, during subsequent discussions with the plant personnel involved in the 3/14/99 testing, plant engineering became aware that the actuator manual override shaft keys had been reinstalled immediately after they were discovered loose during that testing. Further evaluation determined that manual override assembly design on 2SV1 and 2SV7 was intended for applications where, in lieu of set screws, gravity keeps the keys in place due to the valve orientation. However, the orientation of 2SV1 and 2SV7 is such that gravity tends to help loosen the keys. Since this design provides no positive means of retaining them in place, the keys for 2SV1 and 2SV7 loosened, probably as a result of normal remote valve operation. Without their respective keys engaged, manual actuation of 2SV1 and 2SV7 was not possible. Consequently, these valves were declared inoperable on 5/4/99.

A review of past surveillance testing results and work orders determined that the last successful manual cycling of 2SV1 and 2SV7 occurred during the first performance of PT/2/A/4250/033 on 12/13/97. Prior to 12/13/97, there was no TS applicable to the SG PORVs nor were there any test procedures or requirements for verifying proper manual operation of the SG PORVs. Although there were no TS requirements to do so, PT/2/A/4250/033 was developed to verify that manual operation of the SG PORVs, as credited in the SGTR accident analysis, was available. After the 12/13/97 testing, manual operation of 2SV1 and 2SV7 was not attempted again until the next performance of that test on 3/14/99 which identified the loosened keys on the valves. Note that quarterly stroke testing of these valves was performed between 12/13/97 and 3/14/99. This was performed by remotely operating 2SV1 and 2SV7 (remote operation is not affected by loose manual override shaft keys). It is possible that this remote operation caused the keys for these valves to become loose. However, both 2SV1 and 2SV7 were cycled manually at least twice following reinstallation of the loose keys. Subsequent inspection of these valves showed that their manual override shaft keys were engaged properly. Since the above review failed to conclusively identify any work or testing that would indicate when and why the keys associated with 2SV1 and 2SV7 may have loosened following the 12/13/97 testing, it is unknown when manual operation of these valves became impaired. As a result, it is possible there were not three operable SG PORVs as required by TS 3.7.4 from STS implementation on 11/14/98 until 3/13/99, the point in the Unit 2 EOC12 outage when SGs were no longer relied on for cooldown. This

represented a TS prohibited condition since the period of inoperability could have exceeded the action completion time of TS 3.7.4. A review of work orders and problem reports associated with the Unit 1 and Unit 2 SG PORVs identified only one other instance of a SG PORV failure attributable to loose actuator manual override shaft keys. This occurred on 2SV1 in July 1996 prior to implementation of TS 3.7.4. The key for 2SV1 was replaced and no similar events occurred until the event described in this LER. Since the failure mode for the July 1996 failure is similar to the event being reported in this LER, the impaired manual operation of 2SV1 and 2SV7 is considered a recurring event.

Subsequent to the discovery of the inoperable 2SV1 and 2SV7 valves, inspections of the other Unit 2 SG PORVs and all the Unit 1 SG PORVs revealed that their manual override shaft keys were installed properly. This inspection also identified that these other PORVs had set screws which provided a positive means of holding their keys in place. An evaluation was initiated to determine why 2SV1 and 2SV7 did not have manual override shaft key set screws. The drawings and documentation associated with the SG PORVs do not show the level of detail that would indicate whether set screws should be installed. Discussions with the vendor for the actuator did not provide any clarification of this issue. A review of modifications, work orders, and problem reports associated with the Unit 1 and Unit 2 SG PORVs did not provide any evidence that set screws were removed from 2SV1 and 2SV7 or that set screws had been added at some point to the other Unit 2 SG PORVs and the Unit 1 SG PORVs. Based on the above, it was concluded that 2SV1 and 2SV7 never had manual override shaft key set screws. Given the orientation of these valves in the piping, the lack of set screws allowed the keys for these valves to loosen, probably due to normal remote valve operation. Consequently, the cause of this failure was determined to be a design misapplication.

Conclusion

This event did not result in any uncontrolled releases of radioactive material, personnel injuries, or radiation overexposures. This event is Equipment Performance Information Exchange (EPIX) reportable.

On 5/4/99, 2SV1 and 2SV7 were declared past inoperable since manual operation of these valves was impaired due to loosened manual override shaft keys. The cause was determined to be a design misapplication in that the keys for 2SV1 and 2SV7 have no retaining set screws. Since it cannot be determined when the keys loosened, manual operation of these valves may have been impaired from 12/13/97 until 3/14/99. Consequently, there may not have been three operable PORVs as required

by TS 3.7.4 from 11/14/98 to 3/13/99. This represented a TS prohibited condition since the valves may have been inoperable for a period of time exceeding the action completion time of TS 3.7.4. Note that this condition existed prior to implementation of Technical Specification 3.7.4 when similar Steam Generator Power Operated Relief Valve operability requirements were contained in McGuire Selected Licensee Commitment (SLC) 16.10.1. Since the requirements of that SLC may not have been satisfied, this event also represented a condition prohibited by SLC 16.10.1.

CORRECTIVE ACTION:

Immediate

- The loose manual override shaft keys for 2SV1 and 2SV7 were reinstalled upon discovery and the valves were manually cycled successfully.

Subsequent

- The actuators for SG PORVs 2SV13, 2SV19, 1SV1, 1SV7, 1SV13, and 1SV19 were inspected and the actuator manual override shaft keys were found to be installed properly.
- The actuator manual override shaft keys for 2SV1 and 2SV7 were peened to provide a positive means of retaining the keys in position.

Planned

The following planned actions represent regulatory commitments:

- The actuators for 2SV1 and 2SV7 will be modified to provide a more positive means of ensuring their manual override shaft keys do not loosen.
- Periodic maintenance will be developed to inspect the actuator keys for proper installation.
- The inconsistencies between the McGuire TS BASES and the McGuire UFSAR SGTR accident analysis related to assumed PORV failures and the number of PORVs required for adequate post-SGTR cooling will be evaluated. These discrepancies will be corrected as needed.

SAFETY ANALYSIS:

Based on this analysis, this event is not considered to be significant. At no time were the safety or health of the public or plant personnel affected as a result of the event.

Design Basis

The McGuire SGTR accident analysis contained in Section 15.6.3 of the McGuire UFSAR takes credit for manual operation of the SG PORVs in mitigating the effects and consequences of a SGTR event. During this event, this analysis assumes a loss of offsite power (LOOP) and that the PORV on the affected SG fails to close, requiring local operator action to close the PORV block valve. Upon isolation of this PORV, RCS and SG pressures slowly rise back to their nominal values. Cooldown is then required to reduce RCS temperature to the target subcooled temperature allowing RCS pressure to be lowered to that of the ruptured SG. This depressurization of the RCS eliminates the driving force for breakflow. However, as a result of the LOOP, the condenser steam dump valves automatically close and they are unavailable to perform this cooldown function. Consequently, operators begin cooling down the unit using the SG PORVs on the unaffected SGs. Since the motive force for remote operation of these PORVs (instrument air) is assumed to be unavailable due to the LOOP, manual operation of the PORVs is procedurally directed using the local actuator handwheels. Once initiated, cooldown continues until the target subcooled temperature is reached, at which time the RCS is depressurized enough to stop break flow. The UFSAR SGTR accident analysis assumes that two SG PORVs on unaffected SGs are needed to cool the RCS to the subcooled target temperature in the timeframes needed to support the offsite dose conclusions.

Event Safety Analysis

The limiting dose concerns during a SGTR are associated with break flow out the failed open PORV on the SG with the rupture. Existing procedures incorporate the accident analysis related response time needed to close a failed PORV's block valve such that offsite dose is limited to acceptable levels. The impaired manual operation of 2SV1 and 2SV7 did not affect these response times nor the ability to isolate the failed PORV on the ruptured SG if this PORV had failed open as assumed in the SGTR accident analysis.

2SV1 and 2SV7 provide the safety related function of containment isolation. These valves are designed to spring close upon receipt of an

isolation signal, LOOP, or a loss of motive operating force. This spring to close design was not affected by the inability to manually operate these valves. Therefore, this containment isolation function was not impacted by this event.

McGuire did not experience a SGTR while 2SV1 and 2SV7 were incapable of manual operation during this event. However, if a rupture had occurred, the following two scenarios require analysis:

Scenario #1: SGTR On A SG Not Associated With 2SV1 and 2SV7

If a SGTR had occurred on a SG not associated with 2SV1 and 2SV7, cooldown would then have been conducted using the remaining operable PORV associated with an intact SG (2SV13 or 2SV19). Note that there is no evidence that 2SV13 or 2SV19 were inoperable concurrently with 2SV1 and 2SV7. The UFSAR SGTR accident analysis assumes that two SG PORVs on unaffected SGs are used to cool the RCS to the subcooled target temperature. With only one available PORV on an unaffected SG, the post-SGTR cooldown capacity would have been lower than analyzed. Consequently, RCS pressure reduction would have occurred at a later time resulting in more break flow into the ruptured SG. A sensitivity case study was performed for the scenario in which only one SG PORV is available for the post-SGTR cooldown. The time required to cool the plant down to the target subcooled temperature increased by 10-15 minutes as compared to when two PORVs are available as assumed in UFSAR SGTR accident analysis. This resulted in approximately 5000 gallons of additional RCS leakage into the ruptured SG. Assuming the PORV on the ruptured SG failed open as described in the SGTR accident analysis, all procedure steps associated with closing the stuck open PORV's block valve should have been completed before the RCS cooldown began. Consequently, any increase in offsite dose consequences due to release from the ruptured SG's PORV would most likely have been negligible. These consequences would have been further mitigated by the following:

- Assumptions in the SGTR accident analysis related to the amount of fuel defects and RCS activity are conservative with respect to actual conditions during the period of time that manual operation of 2SV1 and 2SV7 was impaired.

- If a SGTR and a LOOP had occurred, existing plant procedures provide directions to restore instrument air using safety related compressors associated with the plant diesel generator starting air system. It is expected that instrument air would be restored approximately 90 minutes into the SGTR event. Given that non-safety related control

power for the SG PORVs would probably have been available, remote operation of 2SV1 and 2SV7 to support the Unit 2 post-SGTR cooldown would have been possible.

- During a portion of time that manual operation of 2SV1 and 2SV7 was assumed to be impaired, diesel powered instrument air compressors capable of automatic operation were available to provide motive force for remote operation of those valves if a LOOP had occurred.

- The SGTR accident analysis indicates that cooldown starts 80 minutes into the event. If remote operation was not possible, the problem with 2SV1 and 2SV7 would become apparent when manual operation of these valves was attempted. It is expected that the loose keys on 2SV1 and 2SV7 would be identified and corrected, at which point additional cooldown could be provided by these valves.

- If warranted by plant conditions and the potential for significant increase in the offsite dose consequences, cooldown is possible using safety injection and opening the RCS PORVs to provide once through cooling.

The above analysis assumes the PORV on the ruptured SG failed open as assumed in the SGTR accident analysis. If this PORV did not stick open, the dose consequences of this event would be reduced further.

Scenario #2: SGTR On A SG Associated With 2SV1 and 2SV7

If a tube rupture had occurred on a SG associated with 2SV1 or 2SV7, two operable PORVs on intact SGs would have been available to perform the post-SGTR cooldown function (2SV13 and 2SV19). Therefore, RCS depressurization would have occurred within the time frames assumed in the UFSAR. As a result, there would have been no impact on offsite dose consequences assumed in the SGTR accident analysis.

Conclusion

Based upon the above analysis, it is concluded that the response of McGuire Unit 2 to a SGTR event concurrent with a LOOP would not have resulted in a significant increase in offsite dose consequences.