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Proceedings of the Third NRC/ASME Symposium on Valve and Pump Testing

Held at Hyatt Regency Hotel
Washington, DC
July 18–21, 1994

Session 3A – Session 4B

Sponsored by
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Board of Nuclear Codes and Standards
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ABSTRACT

The 1994 Symposium on Valve and Pump Testing, jointly sponsored by the Board on Nuclear Codes and Standards of the American Society of Mechanical Engineers and by the Nuclear Regulatory Commission, provides a forum for the discussion of current programs and methods for inservice testing and motor-operated valve testing at nuclear power plants. The symposium also provides an opportunity to discuss the need to improve that testing in order to help ensure the reliable performance of pumps and valves. The participation of industry representatives, regulators, and consultants results in the discussion of a broad spectrum of ideas and perspectives regarding the improvement of inservice testing of pumps and valves at nuclear power plants.

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DISCLAIMER AND EDITORIAL COMMENT

Statements and opinions advanced in papers presented at the Third NRC/ASME Symposium on Valve and Pump Testing are to be understood as individual expressions of their authors and not those of the American Society of Mechanical Engineers nor the U.S. Nuclear Regulatory Commissión.

The papers have been copy edited and recast into a standard format. By consensus, English units have been used as an expression of current industry practice.

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Session Chair
Dr. Nabil Schauki
Seimens Power Corporation

Model Testing on Inlet Chambers of Cooling Water Pumps

Falco Schubert, Ph.D.
Siemens-KWU

ABSTRACT

This paper discusses a series of tests performed at the Institute of Fluid Flow Machines in Kaiserslautern, Germany. The tests were designed to investigate the effect of replacing one of the steam turbines in a power plant. The new turbine required more cooling water flow through the condenser, which called for new cooling water pumps. The model tests showed that reliable, long-term service would be impossible without modifying the equipment. The test model was built to use Froude's law to investigate the effects of the changes.

INTRODUCTION

A licensee wanted to replace one of the steam turbines in an electric and heat power plant. The new turbine required a greater cooling water flow through the condenser, so new cooling water pumps (CWPs) should be installed in the existing inlet building. The CWPs take suction from a river, so different water levels can occur in the inlet building.

The design of the inlet building was narrow and crooked, and a first estimation carried out by Siemens-KWU showed that a reliable long-term service would be impossible. So a model test was initiated at the Institute of Fluid Flow Machines (SAM) in Kaiserslautern, Germany, to find the optimal solution regarding

- Acceptable flow conditions
- Low amount of changes or additional work in the inlet building
- Low overall costs.

The model tests showed that a reliable long-term service would be impossible without modifications, as was found in the first estimation. A bottom whirl was found at one of the CWPs in the No. 3 inlet chamber (these CWPs take suction from the same inlet building as the new CWPs). The licensee confirmed that this CWP was repaired some time ago because of lower bearing damage.

For the new CWPs in the No. 2 inlet chamber, modifications were evaluated and tested. A solution was found requiring minimum modifications at the existing inlet structure. The solution offered good results according to flow pattern, despite high flow velocities and low water levels within the inlet building.

The test model was built according to the model laws, especially Froude's law. This was verified during the experiments in the research institute, according to the latest U.S. publications (Melville et al., 1993). The model tests were documented by videotape.

The new steam turbine and the modified cooling water system have been on full-load service since autumn of 1993. The CWPs were found to run smoothly and without vibrations or other problems, and the water surface within the inlet chamber was flat and did not show any beginning eddies.

THEORETICAL BACKGROUND

The hydrodynamic behavior of the flow inside a pipe or a pump depends on the Reynolds number (Re). The Reynolds number describes the ratio of inertia forces and friction forces. The

similarity of a model to the original shape is given if the Reynolds numbers are identical.

$$Re = c*d/v \quad (1)$$

If the flow has a free surface, the ratio of inertia forces and gravity forces is of interest. This ratio is described by the Froude number (Fr).

$$Fr = c2/(g*h) \quad (2)$$

In the case of a pump chamber, the flow pattern depends on both Reynolds and Froude numbers, as is shown on Figure 1. At the surface (Section A-B), the flow pattern depends on the Froude number. Below the surface (Section C-D and E-F), the Reynolds number is dominant.

If a model test should be carried out, similarity to the original building is given if

- Model and original are geometrically similar
- Flow patterns are hydrodynamically similar (i.e., Froude number and Reynolds number are constant)
- The flow is kinematically similar (i.e., no back flow from the pump impeller into the pump inlet chamber occurs).

The Weber number is of no interest for the model tests.

If the velocity ratio c_M/c_O is calculated with Equations (1) and (2), the following comparison can be made (Index M refers to model and index O refers to original):

Reynolds number $c_M/c_O = d_O/d_M$ (3)

Froude number $c_M/c_O = (h_M/h_O)^{(1/2)}$ (4)

where

v_O	=	v_M same fluid
g_O	=	g_M gravity remains constant
d_M, d_O/h_M, h_O	=	a characteristic length (i.e., the pump pipe diameter), so that d_M/d_O is the model scale.

The d_M/d_O ratio can only be equal in Equations (3) and (4) if the model scale (d_M/d_O) is 1. This is the trivial solution. It is not possible to meet both model laws without changing the fluid, the gravity, or both.

Fortunately, the experience with model tests on inlet chambers shows that good results can be obtained if the following points are taken into account:

- The model must be true to scale
- The Froude number must have the same value for the original and the model
- The model scale d_M/d_O must not be less than 1/15
- The model diameter of pump suction should not be less than 50 mm
- An increase of Froude number during the model test must have no visible influence on effects that depend on the Reynolds number.

The last point seems to be of special interest to low scale models. Nevertheless, this test should be done independent of the model scale. If changes in the Reynolds-dependent flow pattern are clearly visible on this test, a model can influence the flow.

In fact, the Reynolds number is of minor influence on inlet chamber model tests. Bottom whirls can be clearly seen because small air bubbles in the water are separated in the whirls. If a rotation of the suction pipe flow is detected, measures must be taken to avoid it. The real size of the rotation or the rotation velocity is generally of no interest.

INITIAL SITUATION

Figure 2 shows an outline of the inlet building. The pumps in Chambers 2 and 3 were originally

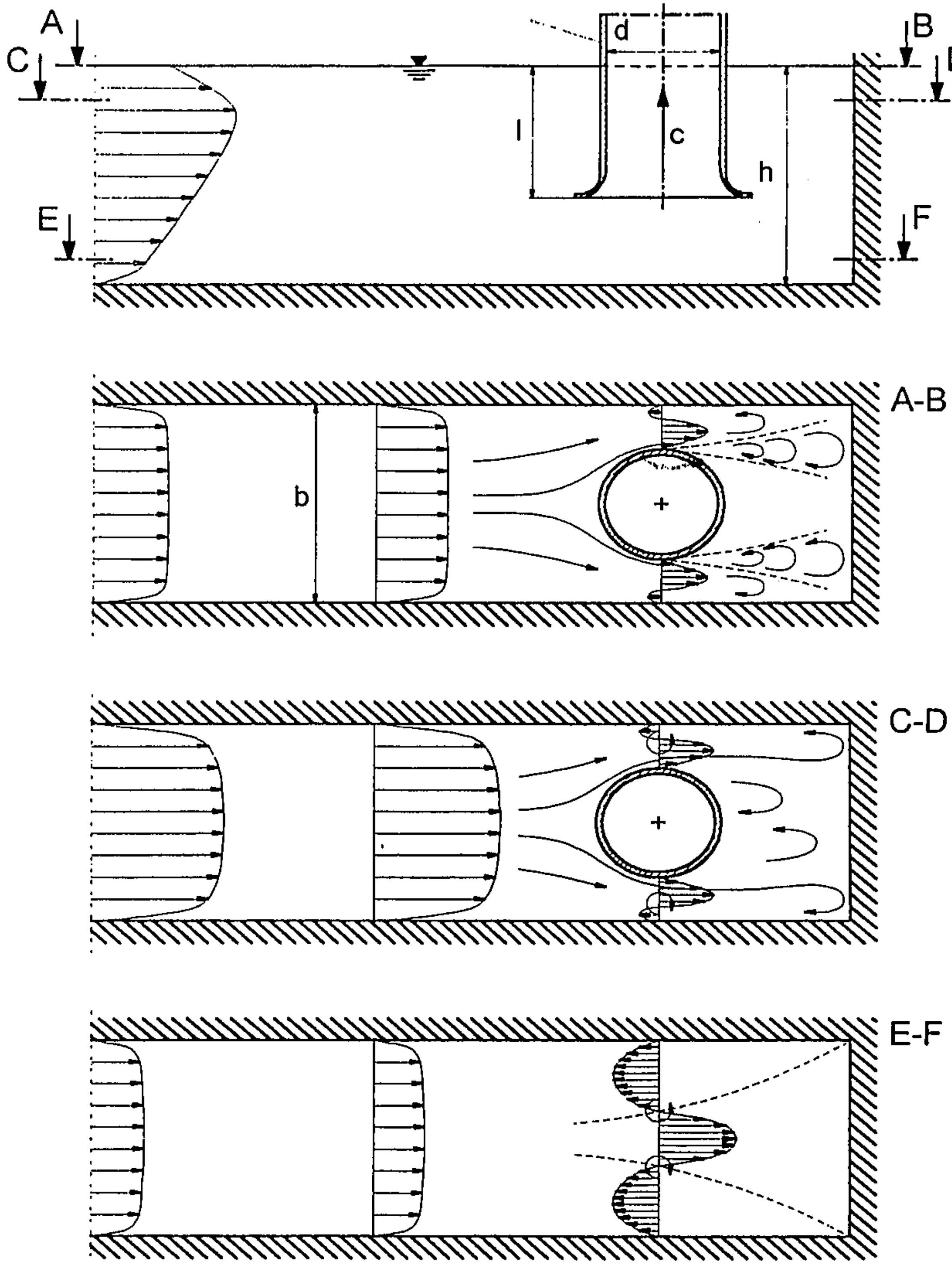

Figure 1. Flow pattern in an inlet channel dependent on Froude and Reynolds numbers:
Section A-B: Surface whirls may cause eddies. Froude number is decisive.
Section C-D: Whirls behind the pump column according to Reynolds number.
Section E-F: Bottom whirls caused by shear flow.

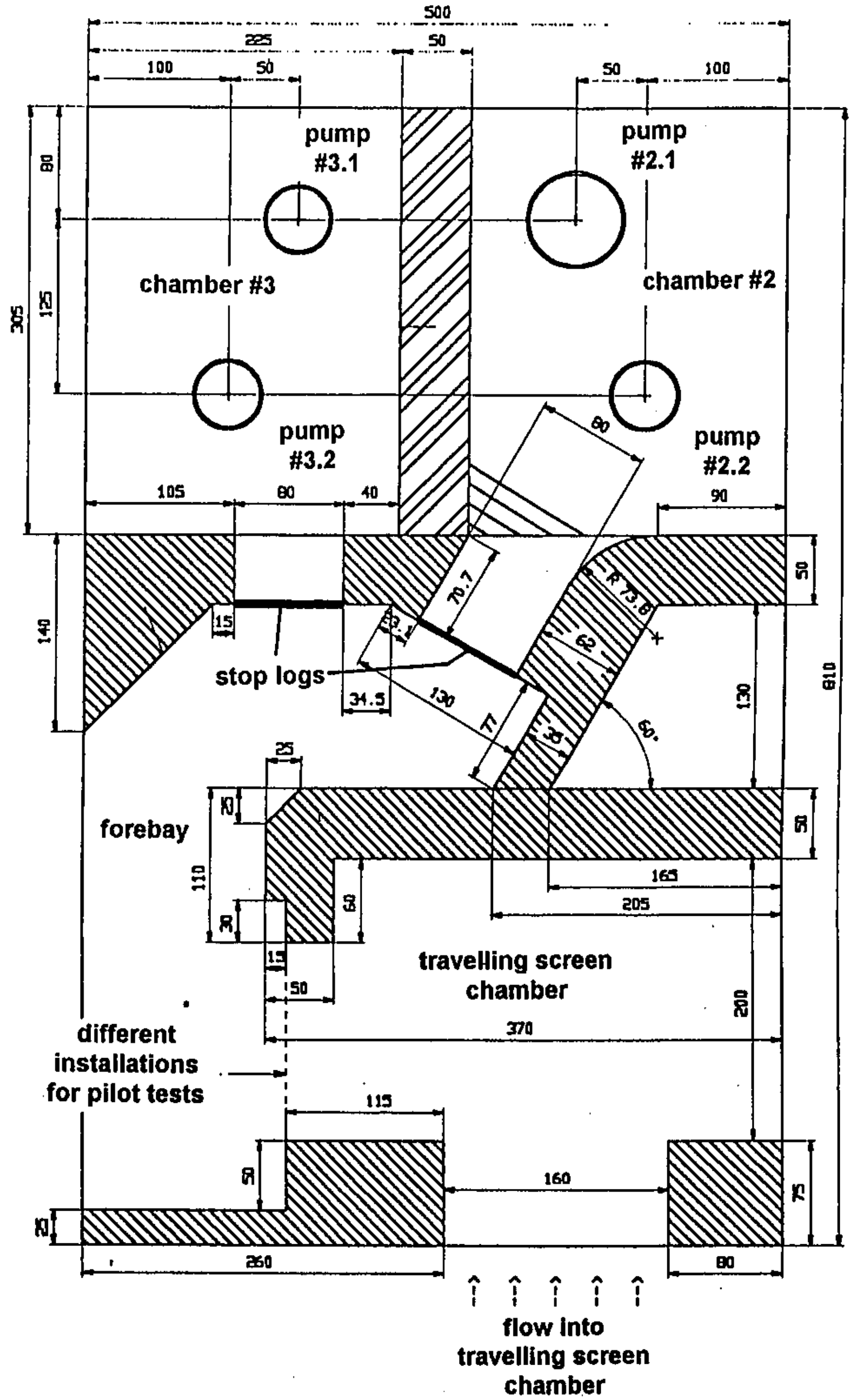

Figure 2. Outline drawing of the inlet chamber model. (Pilot tests showed that the forebay water level was the most important parameter. The travelling screen and even the outlet geometry to the forebay had no remarkable influence. The model was designed and built to allow geometrical changes within a short time The model tests were carried out at the Institute of Fluid Flow Machines (SAM) of the Technical University of Kaiserslautern, Germany.)

the same size. Now the size of the No. 2 pumps must be increased to match the greater cooling water requirements of the new turbine condenser. Two different pumps have been chosen to optimize the power requirements at partial load conditions.

Both chambers could be separately isolated from the inlet channel by stop logs (Figure 2).

Because of the 1.3 (maximum 1.7) times increased flow, the licensee had doubts if the pumps could work properly with the low intake water level. Siemens was contacted for a third-party review. A first and rough estimation of the head losses in the intake structure and the cleaning facilities showed that at lower river water levels the stop log area of Chamber 2 would only partly fill. That would cause the Chamber 2 water level to dramatically decrease because of the weir flow through the stop log. It would be impossible to run the No. 2 pumps at these conditions.

Because the licensee had already ordered the new pumps, information about any necessary modifications had to be given to the manufacturer quickly. On the other hand, important changes in the concrete structure of the building had to be considered by the architect for calculation and execution. In the worst case, the concrete walls between Chambers 2 and 3 and between the chambers and the forebay might have to be removed.

Siemens proposed to carry out model tests immediately. These tests were designed to document the original situation and offer a solution for changes in the concrete structure as well.

Thus, the conditions for the model test execution have been

- Documentation of the original situation
- Solutions for trouble free operation of the new No. 2 pumps
- Optimization regarding low overall costs and minor changes in the existing concrete structure
- Short time schedule.

Finally, Siemens was authorized to initiate the model tests. As a partner for execution of the tests, the Institute of Fluid Flow Machines (SAM) of the Technical University of Kaiserslautern, Germany, was identified. The licensee agreed to authorize SAM with the tests under the competence of Siemens.

In the beginning, possible solutions were discussed with the institute members. As a result, the model was designed with a number of removable and interchangeable parts because there would be no time to change the model structure later. SAM and Siemens decided to choose a 1:10 scale model with parts made mainly of Plexiglas for good visibility of the flow pattern inside the chambers. The model test stand could be designed, fabricated, and erected in only 4 weeks.

MODEL TESTS

At the beginning of the test series a number of points were checked that might influence the flow pattern inside the pump chambers:

- Bar screen
- Geometry of inlet opening to traveling screen chamber
- Traveling screen
- Outlet of traveling screen chamber.

The experiments showed that none of these points had a noticeable influence on pump chamber flow pattern. They only decreased the forebay water level because of different head losses. Thus, a minimum water level in the forebay according to maximum flow, maximum head losses in the cleaning facilities and the inlet structure, and the minimum river water level were defined. The aim was to modify the structure so that full-load service with all pumps at the minimum forebay level would be possible without run time limits.

DOCUMENTATION OF THE ORIGINAL SITUATION

Pump Chamber 2—High Water Level

The pumps were installed at the proposed position (where the former No. 2 pumps had been). As offered by the pump manufacturer, the pumps had no splitters or inlet cones. When the No. 2 pumps ran with high water level, no surface eddies occurred. At the inlet of pump No. 2.1, a bottom whirl appeared at all flow conditions. Sometimes a vortex was observed between the bellmouths of both pumps, as is shown in Figure 3.

A long-term service under these conditions would have been possible, but there would have been a risk of damage to the No. 2.1 pump after a few years in service.

Pump Chamber 2—Minimum Water Level

In decreasing the forebay water level, the water surface in Chamber 2 became rough and mixed. The bottom whirl of the No. 2.1 pump remained constant. When the water level directly in front of Chamber 2 stop log fell below the upper stop log edge, the flow changed dramatically. The water level inside the chamber decreased by 40% (compared with the forebay water level above ground level). The water dropped in through the stop log like a cataract, and the surface was extremely turbulent and very rough (Figure 4). In addition to the bad suction flow conditions, the No. 2.2 pump would be heavily affected by mechanical impact.

It was interesting to see that because of the rough surface, eddies could not exist. On the other hand, many bubbles were sucked into the pumps. Obviously, no service was possible under these conditions. If the inlet bay water level was further decreased, the amount of air bubbles sucked into the pumps became so large that the test rig pumps failed. The minimum forebay water level could not be reached.

The test result was as expected in the first rough estimation.

Pump Chamber 3

It was clear at the beginning of the tests that the No. 3 pumps would not be affected by the new No. 2 pumps, other than a slightly lowered water level. In fact, there would not have been a change in flow pattern.

On the other hand, the SAM staff found a bottom whirl at the No. 3.2 pump. The licensee stated that this pump had to be repaired one year ago because of a lower bearing failure. Because of this experience, Siemens was authorized to optimize the Pump Chamber 3 as well. The bottom whirl of the No. 3.2 pump is shown in Figure 5.

CORRECTIVE ACTIONS

According to the model test results of unmodified Chamber 2, the most important measure should be to increase the water level inside Chamber 2 at minimum forebay water level conditions.

The lower stop log wall was removed, which increased the free stop log area by nearly 50%. The tests showed that this measure was sufficient. Because of the decreased dynamic head loss of the stop log area, the water level difference between the forebay and Chamber 2 became insignificant.

The next goal was to avoid the bottom whirls. The pump centerlines should not be removed, if possible. Therefore, the pumps were equipped with inlet cones and splitters. Because of the crooked design of the building structure, the optimal position of the splitters had to be found by the tests. The bottom whirl of Pump 2.1 did not disappear with a standard splitter. It could only be moved into the corner of Chamber 2. Several remedies were tested. Because the center line of the splitter was directed toward the corner, the splitter was elongated into the corner, which

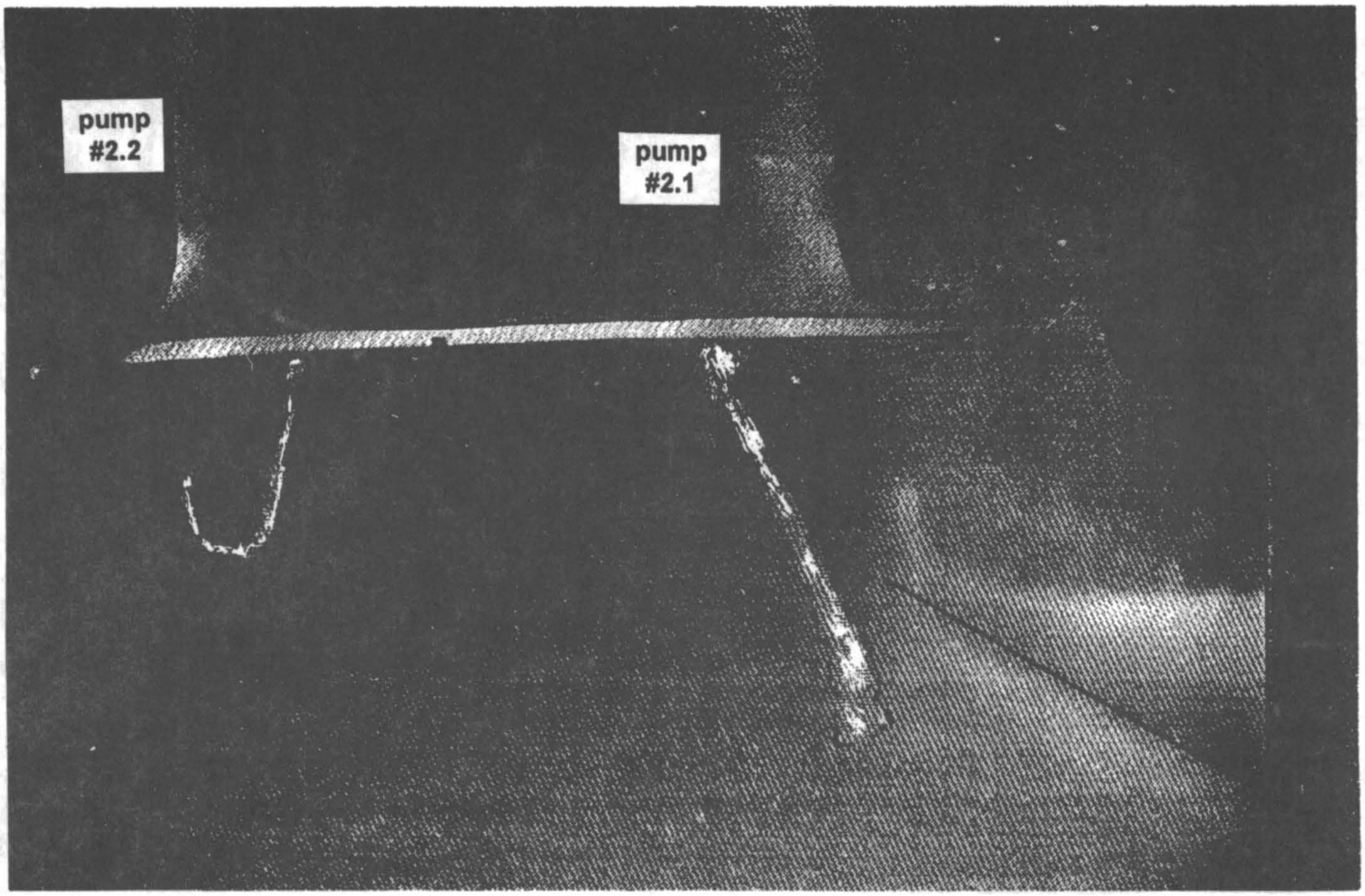

Figure 3. Unmodified inlet Chamber 2. At full-load service and maximum forebay water level a stable bottom whirl at Pump 2.1 exists. From time to time a whirl between both Chamber 2 pumps appears.

caused no additional changes in the existing concrete structure or additional concrete works. The bottom whirl disappeared. Figure 6 shows the completely modified inlet Chamber 2 with the No. 2 pumps running at full capacity.

No whirls appeared from the pumps to the bottom or between the pumps, and no surface disturbances or eddies could be seen. Figure 7 shows Pump 2.1 with the elongated splitter running at full load. It was possible to decrease the forebay water level below the minimum level without creating a rough surface, eddies, or bottom whirls. In addition, no changes in Reynolds number depending flow pattern could be seen when the tests were carried out with 50% more flow.

At the stop log of Chamber 3, the lower stop log wall was removed. Although the conditions for the No. 3 pumps should have been improved because of the decreased velocity level in the stop log area, a bottom whirl Pump 3.1 appeared with this change. This example shows that all changes should be done carefully and that there is no guarantee of success, even if the new conditions indicate improvement.

The No. 3 pumps had originally been installed with a great bottom distance. Now the bellpipes of the pumps were elongated so that the new bellmouths of the pumps had the correct distance to the bottom for installation of inlet cones and splitters. The orientation of the splitter centerlines was optimized by the tests. The No. 3 pumps seemed to be sensitive to different service conditions (i.e., single service or common service of both pumps). The No. 2 pumps were not affected by different service conditions.

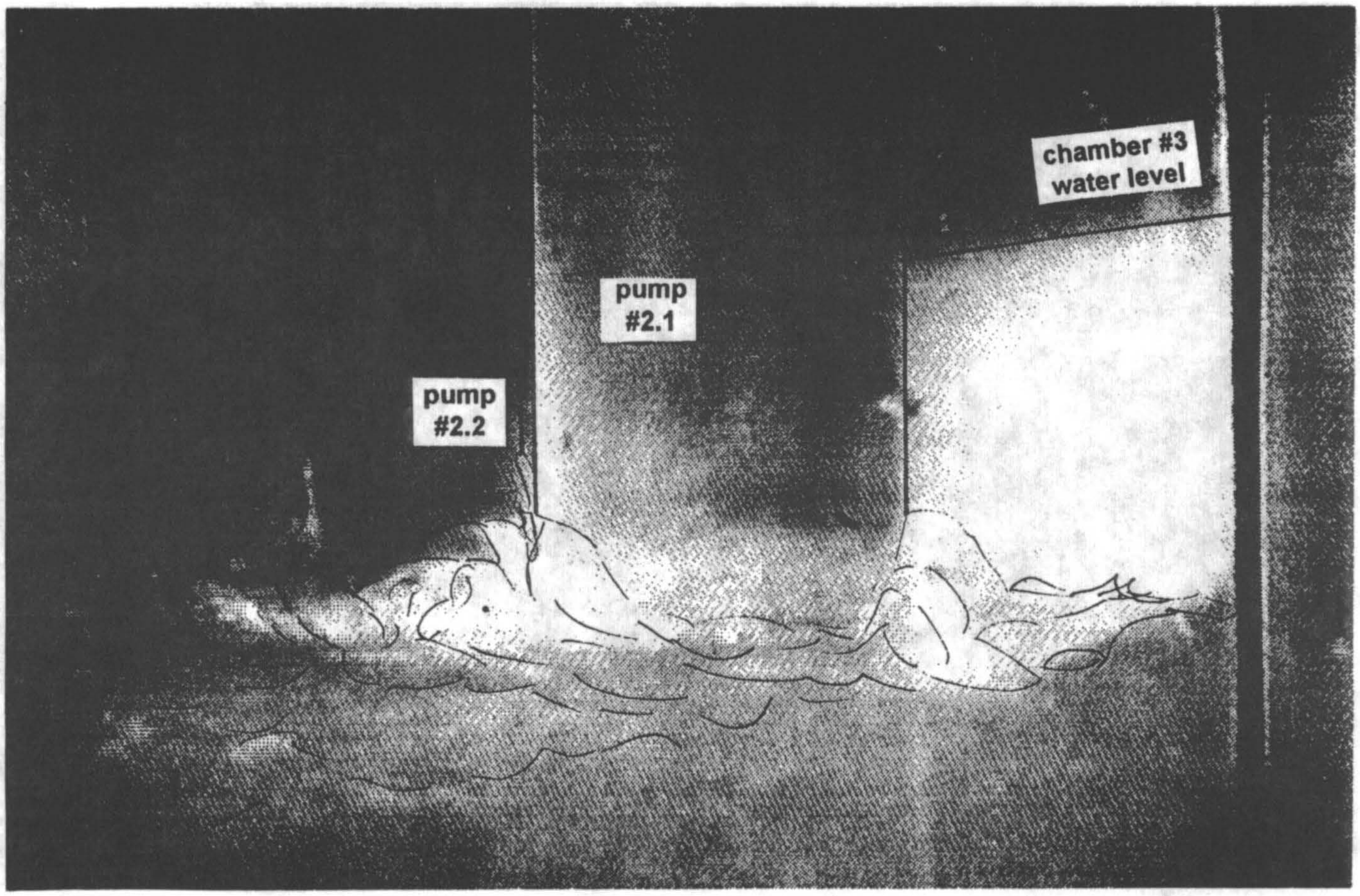

Figure 4. Inlet Chamber 2 water level decreased because of cataract flow through the stop log into the chamber (behind Pump No. 2.2). The Chamber 3 water level in the background is approximately the forebay water level. Full-load service, inlet chamber not modified.

With these remedies—lower stop log wall removed, bell pipes elongated, cones and splitters installed at optimized position—the bottom whirl of Pump 3.2 disappeared. Both pumps could be run below minimum forebay water level without eddies or bottom whirls.

CONCLUSIONS

The inlet chamber model tests were finished within a very short time. Solutions were found for both inlet chambers. The changes in the existing concrete structure were limited without influencing the statics of the inlet building. The practicability of an isolation of both inlet chambers was kept.

The critical water level of the chambers with the improved design was substantially below the minimum forebay water level, and eddies or bottom whirls did not appear.

The modified cooling water system has been on full-load service since autumn of 1993, and the pumps have run smoothly and without vibrations.

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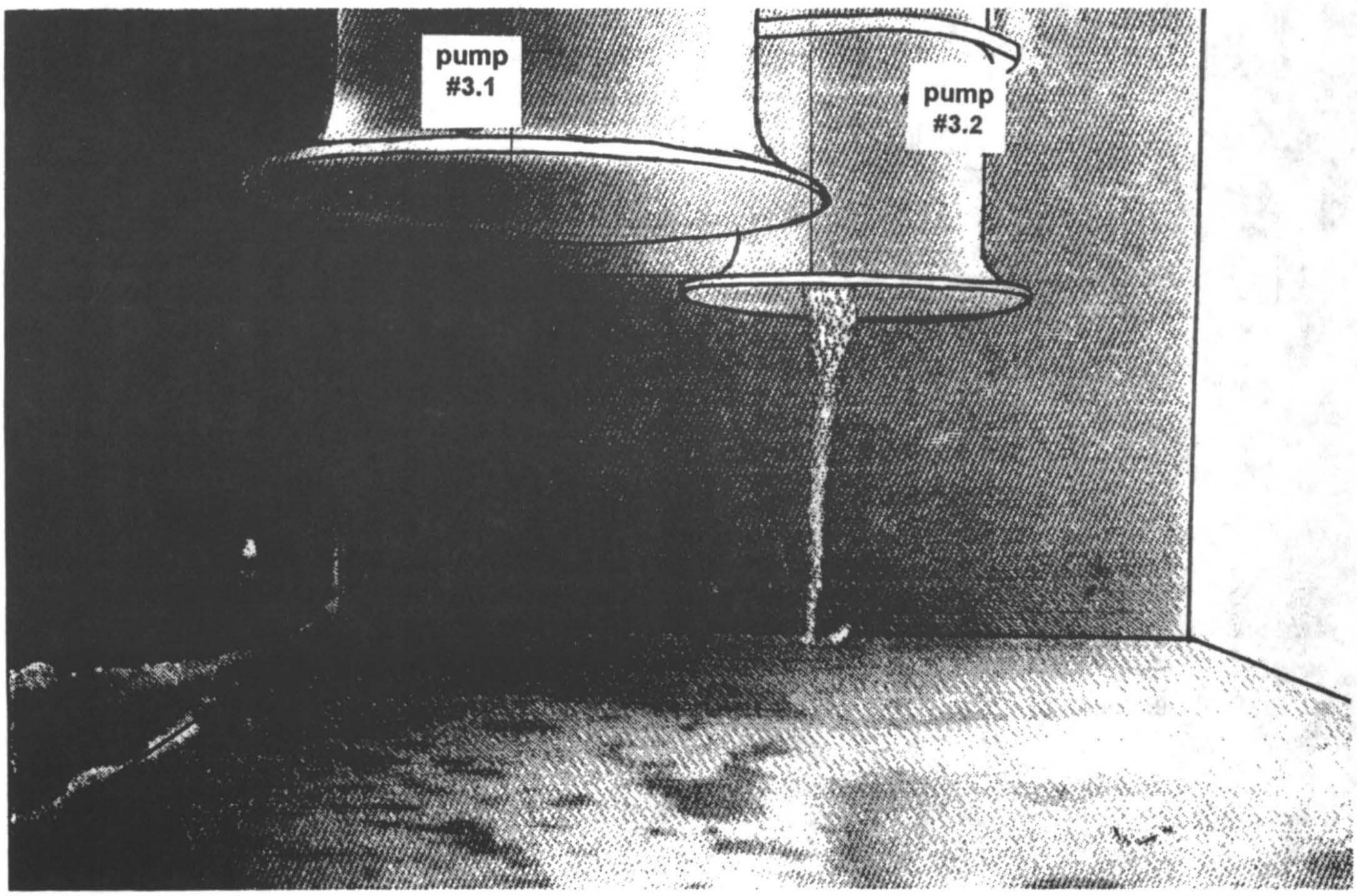

Figure 5. Unmodified inlet Chamber 3. A bottom whirl is visible under all service conditions at Pump No. 3.2. This pump had to be repaired some time before the tests were carried out because of lower bearing failure. Full-load service.

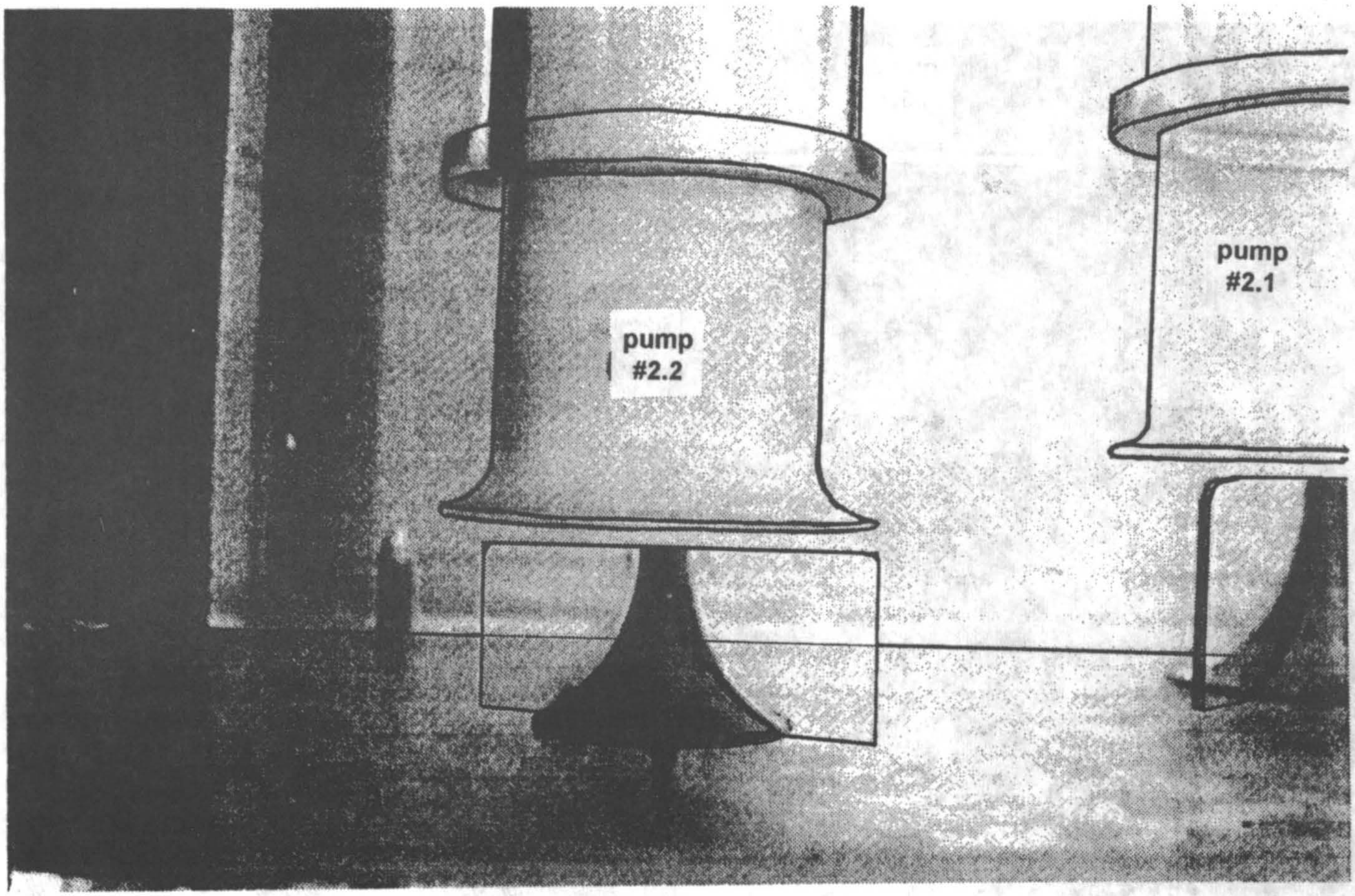

Figure 6. Modified Chamber 2, pumps with inlet cones and splitters. Full-load service, minimum forebay water level.

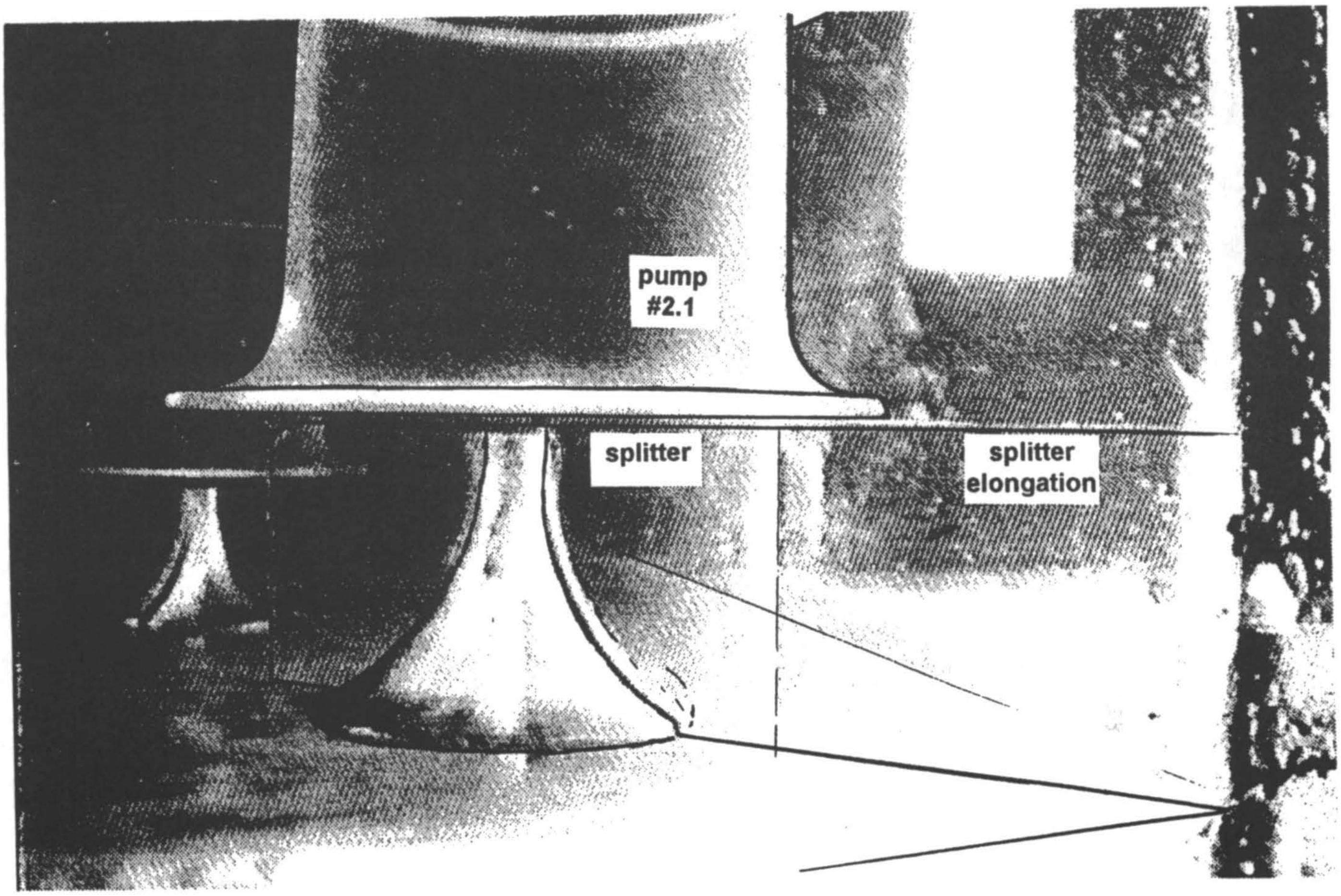

Figure 7. Modified inlet Chamber 2, Pump No. 2.1 with inlet cone and elongated splitter. Maximum forebay water level, full-load service.

Pressurizer Safety Valves Technical Requirements, Testing, Modifications, and Experience

Herr Lothar Werres
Siemens-KWU

INTRODUCTION

Nuclear power plant technology and operating methods are constantly monitored to ensure that they reflect state-of-the-art knowledge and experience. This results in plant-specific update measures. Several systems, areas, and disciplines are usually involved, even when the scope of these measures is limited; therefore, a broad knowledge base is required, particularly in the case of complex measures.

This updating of both technology and operating methods affects both retrofitting and backfitting of the pressurizer system. Central issues in this regard include overall component engineering (including piping and valves), systems engineering, instrumentation and control engineering, and the requisite qualification testing.

MOTIVATION AND GOALS OF RETROFIT WORK

Let's first examine the main reasons for the requisite modifications and retrofit. The pressurizer valve stations that provide overpressure protection for the reactor coolant systems in older German plants were, at the time of plant construction, state-of-the-art designs for steam discharge during various transient operating conditions. The current state of the art imposes the following protection goals and requirements on the pressurizing system beyond those in force at the time of construction:

- Protection goals
  - Overpressure protection–proper valve function must be ensured during internal system events and external events
  - Stuck open relief valves must be isolated
  - Relieve and reduce pressure in the reactor coolant system during emergency procedures
- Requirements
  - Blowdown of various phases—steam, water, subcooled water, and two phase flow during ATWS
  - Relieve and reduce pressure in the reactor coolant system by manual opening of total PRZ station blowdown cross-section during emergency procedures
  - Installation of H_2 degasing.

The protection goals require that the pressure-limiting function of the valves be ensured during internal system and external events. The system must also be able to isolate a pressure-limiting valve that has stuck open, and reduction of pressure in the reactor coolant system must be possible in the course of emergency procedures.

The requirements on the pressurizing system have been extended considerably, in part as a result of the discussion concerning failure of the reactor trip system in the event of plant faults [anticipated transient without scram (ATWS)], as laid down in the Reactor Safety Commission (RSK) Guidelines of 1984. In addition, the RSK (within the scope of the In-Plant Emergency Procedures 1989) recommends selective manual opening of the reactor cooling system (RCS) pressurizer valves and keeping them open as a backup to secondary side pressure relief (bleed) and feed. This must be implemented by a separate, independent actuation system for the

pressurizer valves. To meet these requirements, proper operation of the valves must be ensured during blowdown of steam, water, subcooled water, and two-phase flow.

Provision for hydrogen (H_2) degasing of the pressurizer valve station is also necessary to prevent H_2 from collecting in the lines upstream of the valves. This could cause the lines to cool and lead to avoidable mechanical and thermal loadings in the event of an open requirement.

These requirements and recommendations require extensive retrofitting or backfitting measures, particularly for older plants. Therefore, a study was performed to find an appropriate overpressure protection and pressure relief concept. The different configurations (Figure 1) were analyzed and evaluated with regard to the requirements set, fluid dynamic loads, ease of installation and maintenance, scope of testing involved in inservice inspections, operational reliability, and cost. Special attention was paid to licensability. Modifications to and upgrades of existing valves were compared with other valve types.

Two designs were developed by Siemens-KWU to meet the requirements.

Concept 1

Concept 1 included modification and upgrading of existing equipment, while retaining the original valve type selected (Sempell/Germany) with the following key features:

- Safety valves flanged to pressurizer relief tank dome
- Pilot valves flanged directly to safety valves, eliminating high-pressure control lines
- Installation of additional bleed pilot valves
- Installation of an H_2 degasing system for all piping above pressurizer
- Upgrading of all existing piping, flange connections, and supports to accommodate increased loads.

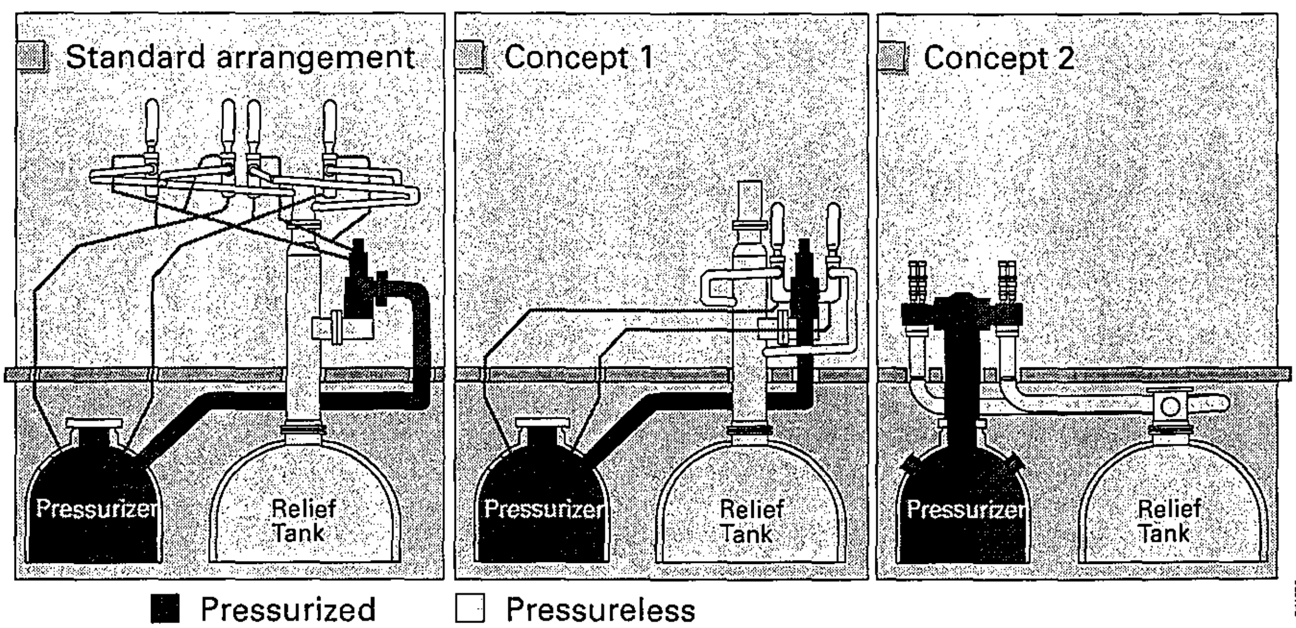

Figure 1. PRZ valve station different configurations.

Concept 2

Concept 2 included installation of a compact valve station directly on the pressurizer with a dome unit and internal pressure relief bores using valves from other manufacturers (Sulzer/Switzerland or SEBIM/France) with the following features and clear advantages over previous designs:

- Reduced piping and verification
- Elimination of all primary pressure-retaining piping such as supply line, pressure relief, and control line
- Low-pressure discharge line
- Simplified valve supports
- Reduced acceleration paths for discharged medium, resulting in lower design loads for all components
- No thermal shock loads resulting from hot design and common degasing equipment for pressurizer, main valves and pilot valves.

TECHNICAL DEVELOPMENT AND QUALIFICATION OF NEW VALVES

Following agreement on valve design, qualification of the selected valves was necessary for implementation. This included extensive testing in Siemens-KWU laboratories (Sempell and Sulzer valves) and in EdF laboratories (SEBIM valve). It was also necessary to account for the original plant arrangements in the test stand.

Testing consisted primarily of the following investigations:

- Functional test of valves with leak test
- Response testing at full flow rate with steam, saturated water, subcooled water, and two-phase mixtures, in part with hydrogen or helium to represent hydrogen
- Determination of opening and closing pressure as well as opening and closing times and blowdown pressure
- Determination of actual discharge flow rate and discharge flow coefficient
- Determination of fluid dynamic and structural dynamic loads.

The following sections present the results obtained for the individual valves.

Babcock Sempell

The pressurizer safety valve is a live-steam-controlled valve that operates on the pressure relief principle. Depending on the requirements, the pilot unit consists of two or three pilot valves (solenoid or pilot valves) as well as a motor-actuated control system for pressure relief (bleed).

The operation of the safety equipment can be seen in the simplified schematic representation in Figure 2.

Under normal operating conditions, all chambers of the safety valve, including the control line, are at operating pressure. If the operating pressure in the system or in the pressure relief line exceeds the set point pressure for the steam pilot valve, the impulse valve opens rapidly following a slight pressure rise. The steam flows through the blowout casing and to the baffle plate, causing it to rise. The check disc in the pilot valve is lifted, thus opening the control line. The pressure drops in the control chambers and pressure differences occur at the actuating piston. The pressure differences induce actuating forces that cause the valve to open.

If the pressure in the system or in the pressure relief line to the steam pilot valve drops below the blowdown pressure, the impulse valve closes in a single stroke. As the baffle plate falls, the check disc also closes, once again isolating the control line.

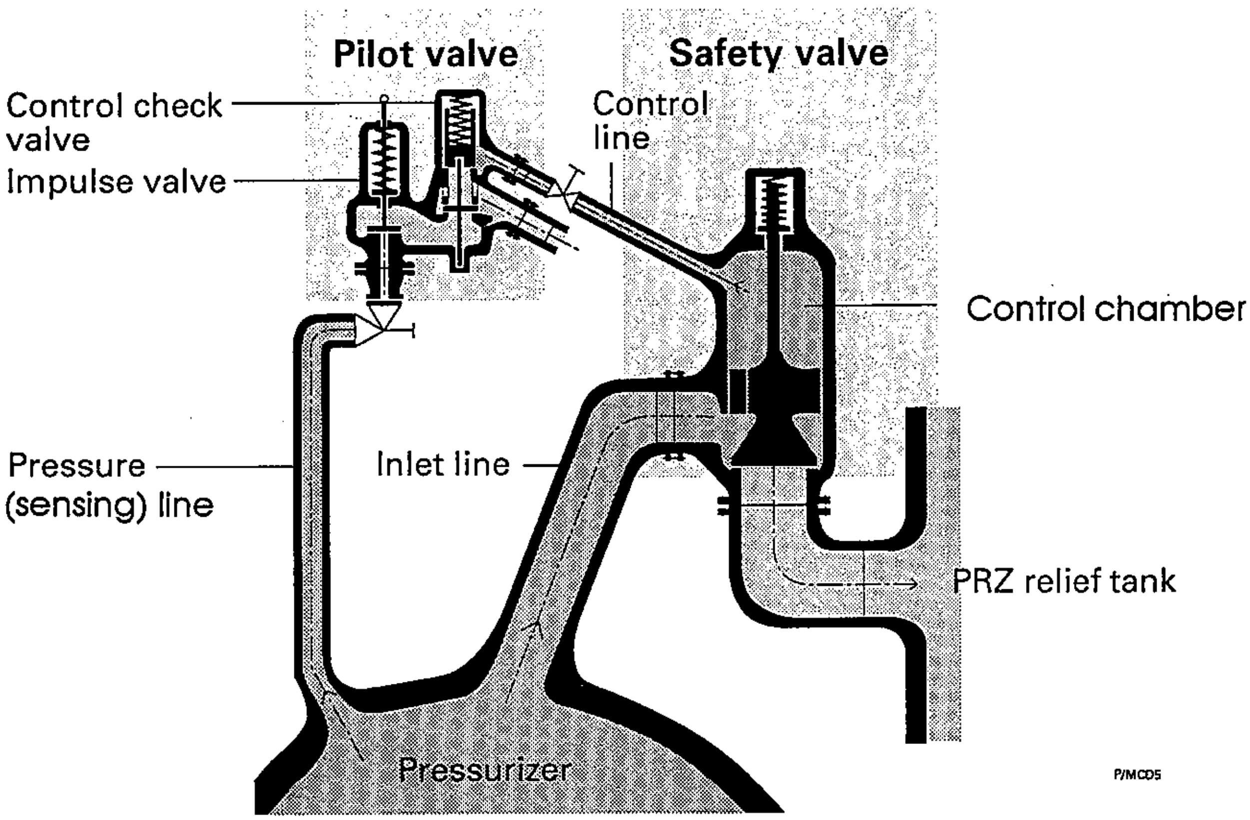

Figure 2. PRZ valve station Sempell safety valve.

The pressure is then equalized in the pilot chambers in the safety equipment, and the pressure difference between the upper and lower sides of the valve disc causes the valve to close.

The pressure relief valve, which is located upstream of the safety valve, is controlled by a solenoid valve. The pressure relief valve is similar in design to the safety valve. It is provided with an isolation valve to minimize the effects of failure of a pressure relief valve to close.

The operational behavior was verified on an original valve with a model of the piping system at full flow rate (300 t/h) on the Siemens-KWU test stand in Karlstein (Figure 3). The valve exhibited stable, reproducible opening and closing behavior for all media conditions. The opening time of the pressurizer safety valve is greater for subcooled water than for steam. The same holds for the closing time.

This investigation included the first test of a pressurizer safety valve in original geometry under ATWS accident conditions. The test evaluations also provided results on the actual flow rate, flow number, and pressure variations as well as reaction forces in the piping. The test data verified the predicted behavior.

Sulzer

The Sulzer safety valve system consists of a live-steam-operated safety valve and spring-loaded pilot valves that are flanged to the safety valve. The safety valve operates on the "charging principle." Depending on requirements and design procedures, at least two spring-loaded control valves are flanged directly to the safety valve. In addition, motor actuation is provided for pressure relief (bleed). The operation of the safety valve is shown in a simplified schematic (Figure 4).

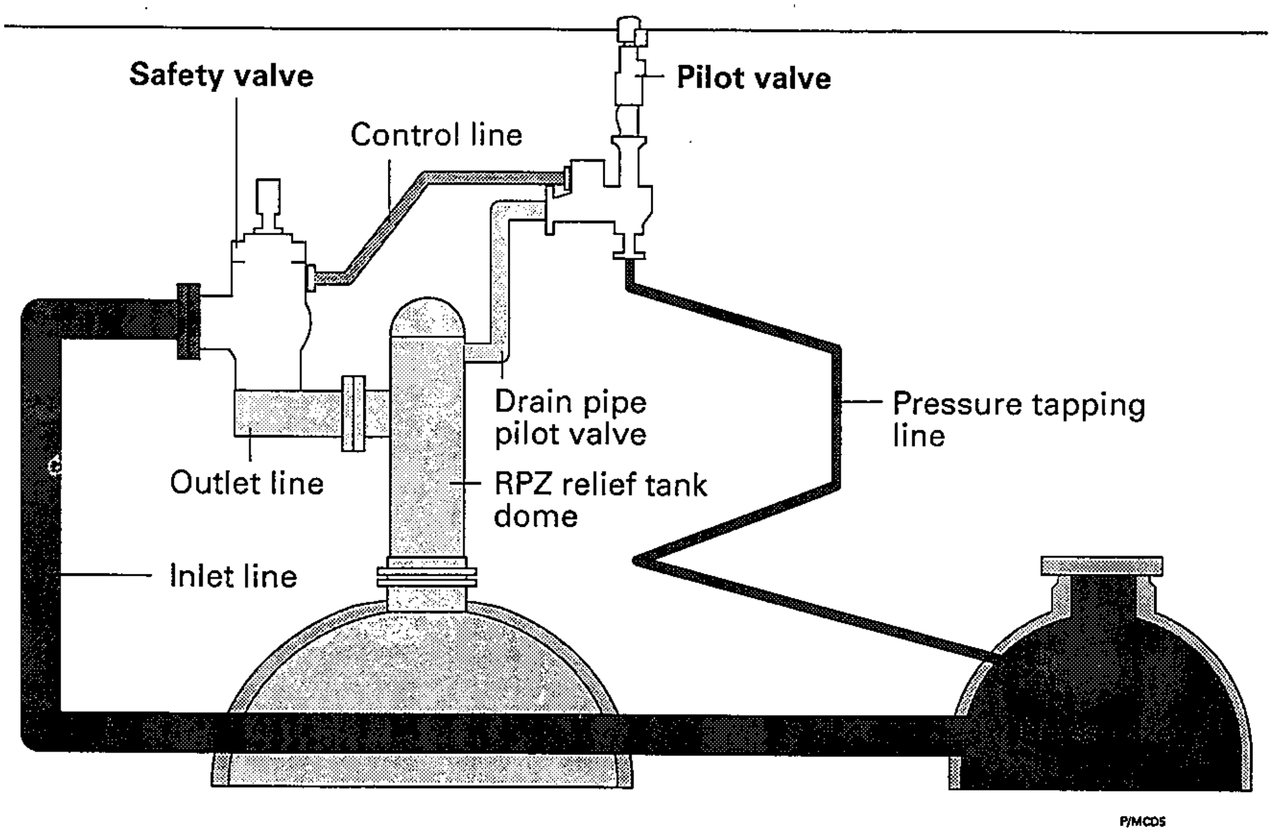

Figure 3. PRZ safety valve testloop arrangement.

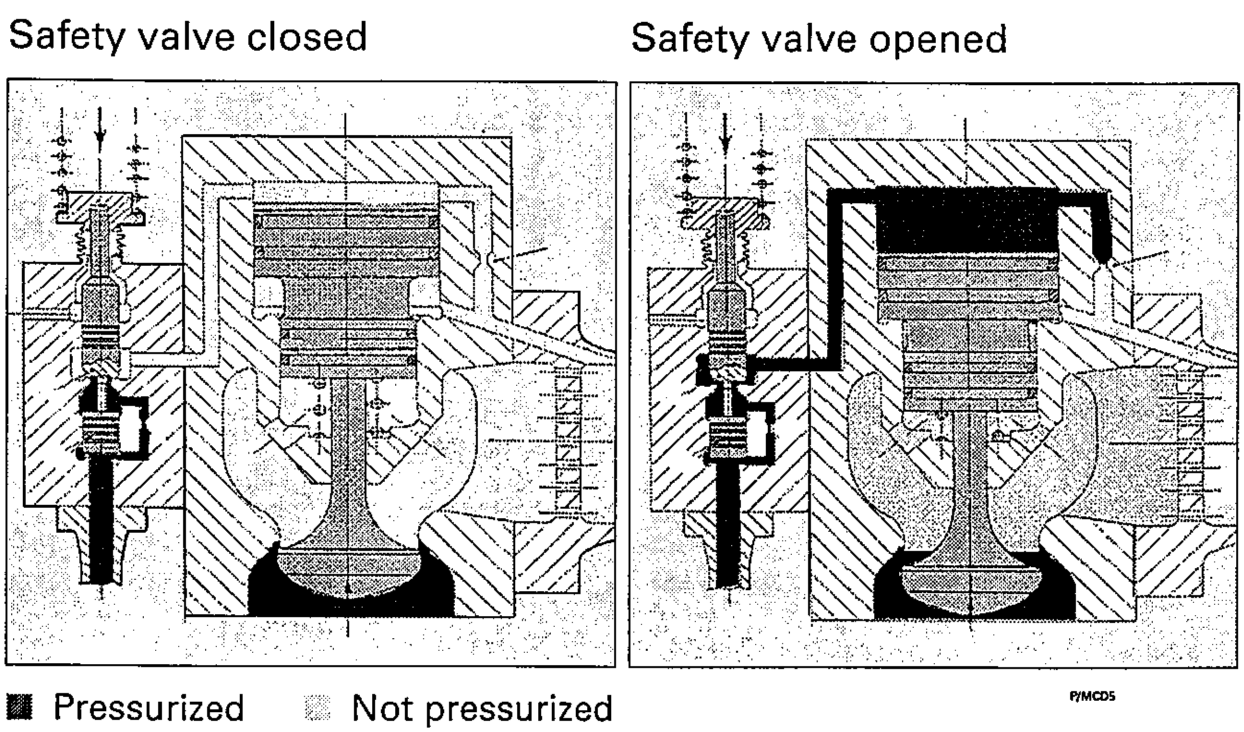

Figure 4. PRZ valve station Sulzer safety valve.

When the set point pressure is exceeded, steam flows through the open pilot valve into the upper piston chamber of the main valve. This causes a pressure force to act on the main piston, and the main valve opens against the system pressure acting on the valve disc. Because the main piston has nearly twice the area of the valve disc, the valve begins to open when the pressure in the upper piston chamber is roughly 60% of the system pressure.

When the pilot valve closes, the pressure supply to the upper piston chamber is interrupted. The pressure in the upper piston chamber is relieved via pressure relief orifices and past the piston rings through the blowdown nozzle. The main valve closes when the pressure in the upper piston chamber has dropped below 40% of system pressure.

The pressure relief valve, which is similar in design to the safety valve, is operated by solenoid valves. The pressure relief valve is equipped with an additional isolation valve to meet the protection goal for a "pressure relief valve which has stuck open."

A 360-t/h prototype valve of this type was tested on the same Siemens-KWU test stand in Karlstein as used for the Sempell valve. The tests were also performed at full flow rate under the various required fluid conditions (steam, saturated water, subcooled water, and two-phase flow with hydrogen). The valve exhibited reliable and stable positioning behavior throughout the entire test series. The measured opening and closing times indicated that this valve is relatively slow. This results in low reaction forces and low loads on the piping system. Actuation times increased considerably for subcooled water, but are in the allowable range for system protection.

Based on past experience with previous valves of this type in a German plant (boron deposits with a negative impact on operation as a result of leaking pilot valves), extensive further testing of materials suitability, boron deposition and valve sealing behavior was performed at Siemens-KWU. The original valves were completely assembled in the Siemens component laboratory in Erlangen for these tests. During the investigations, problems arose with valve sealing, boron deposits, and sluggish operation. The improvements implemented, such as materials and design changes in the pilot valves and the main valve seal, were tested for their effectiveness. The results achieved approval of the inspection agency, owner/operators (Obrigheim, Neckar 1), the valve manufacturer, and Siemens. Therefore, the valves could be installed in the plants following overhaul of all components. No problems arose on initial startup and testing and inservice inspection of the pressurizing system valves.

SEBIM Valve

Because of the more stringent requirements on valves for pressure control and selective pressure relief, reliable closure of the pressurizer valves has become increasingly important in recent years. Primary-side pressure control with SEBIM safety valves is characterized by two series-connected valves in a tandem configuration (Figure 5). In normal operation, the first valve is closed and provides overpressure protection. The second valve, downstream of the first, is set at a lower pressure and hence remains open. In the event the first valve malfunctions and remains open, the second valve closes and takes over the overpressure protection function. The second safety valve thus prevents an uncontrolled loss-of-coolant accident.

SEBIM main valves are live-steam-operated and function based on the relief principle. The necessary relief and loading operations are performed through the control line and a control valve DCM. A design with several lined-up control lines is not possible with this valve type.

The operation of the safety valve can be seen in the simplified schematic (Figure 6). System pressure acts on the Belleville spring of the pilot valve through the impulse line (which has no flow) by way of the annular piston. In normal operation the

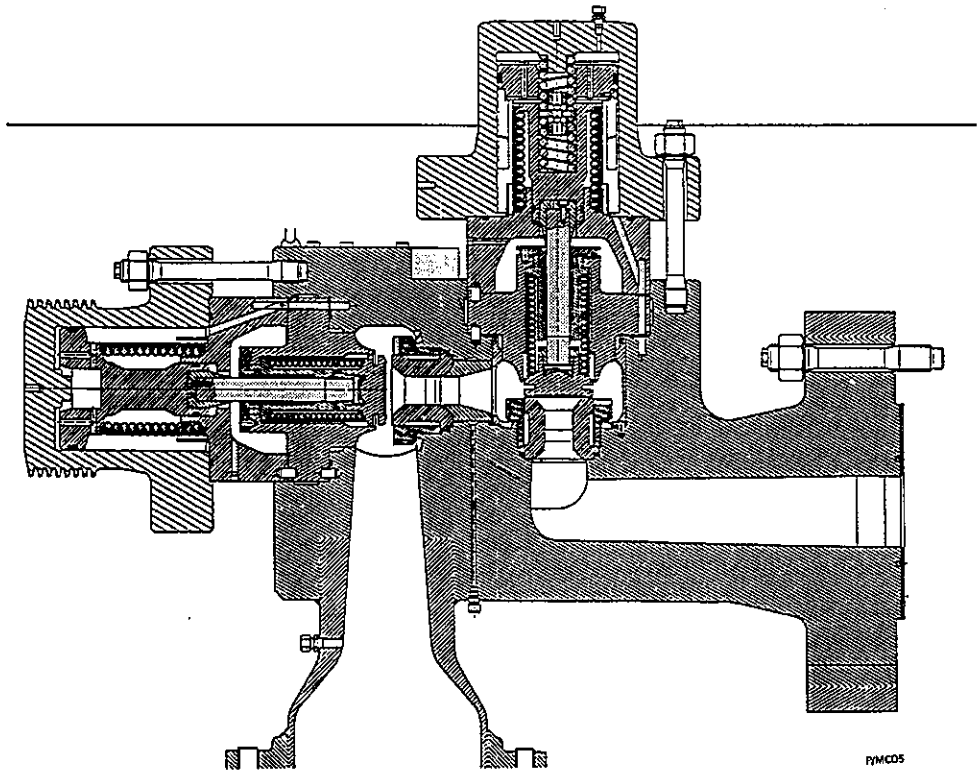

Figure 5. PRZ valve station SEBIM tandem safety valve.

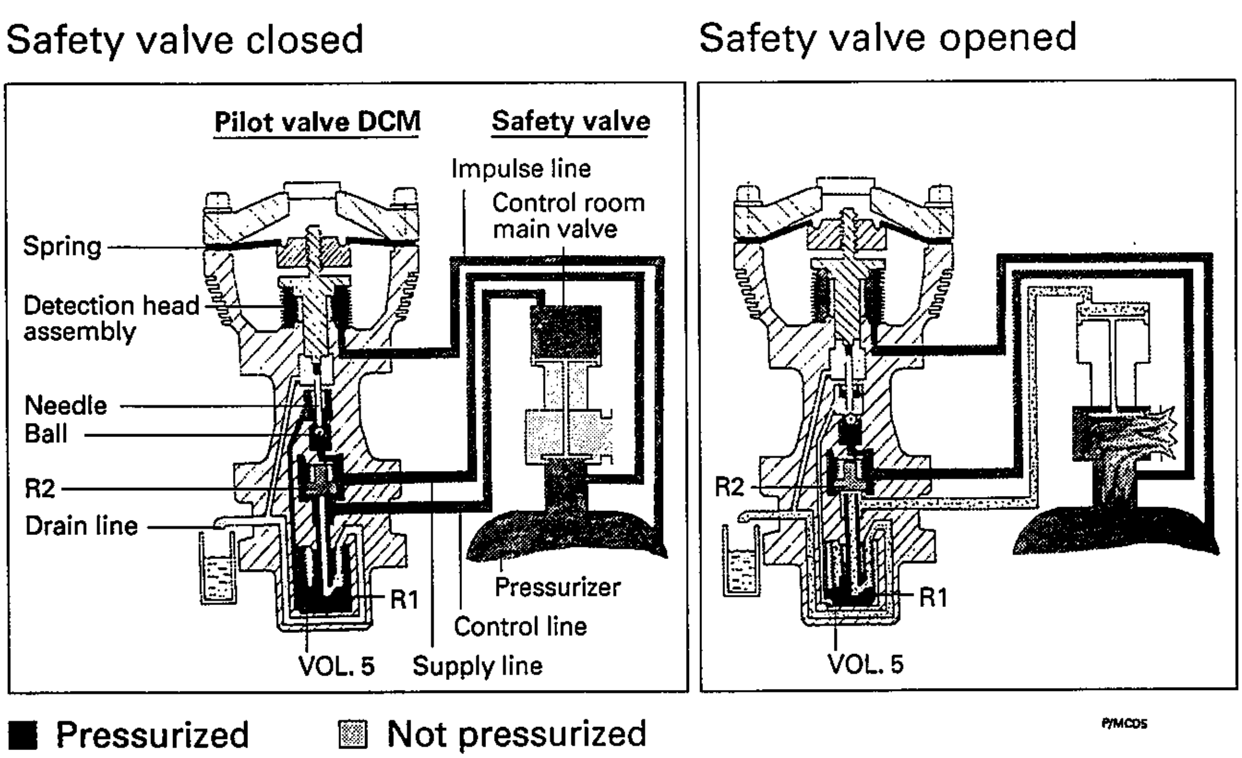

Figure 6. PRZ valve station SEBIM pilot valve DCM—operating schematic diagram.

ball is pressed down from its seat by the Belleville spring, the annular piston, and the hollow needle. In this way, the system pressure is also available in Volume 5 underneath piston R1. Consequently, hollow piston R1 is in its upper end position and in close contact with piston R2, which also is in its upper end position. Because of the free connection between the supply line and the control line, the control chamber of the safety valve is subject to system pressure and the main valve is closed.

As system pressure rises, the annular piston moves towards the Belleville spring and the hollow needle moves upward. The ball is pressed into its seat by the spring below. Volume 5 is isolated from the supply line and hence from system pressure. As the Belleville spring travels further, the hollow needle lifts from the ball. Volume 5 is relieved through the hollow needle and the drain line connected to it at its upper end. As a result, pistons R1 and R2 are pressed down. On reaching its seat, piston R2 isolates the control line from the supply line and hence from system pressure. Piston R1, which continues to travel downward as a result of the bellows force and its own weight, then opens the discharge cross section. The control chamber is relieved through hollow piston R1 and the space between both bellows to the drains system. The closing process takes place in reverse order.

The requisite functional testing was performed on a prototype valve on the same EdF test stand at full flow rate (120 t/h). The tests were also performed under all required media conditions. These experiments are not yet complete; however, initial results indicate stable, reproducible opening and closing behavior under all fluid conditions.

The planned design represents a further development as a hot design on the pressurizer dome. The implementation of valves used in other plants as a cold solution with hydraulic seal does not meet German requirements.

TECHNICAL PROCESSING AND MODIFICATION PROCEDURES

Siemens-KWU had overall responsibility for the Obrigheim and Neckar 1 projects. The technical processing of these projects included systems and process engineering design and verification, plant design, component integration and calculation, planning of electrical and instrumentation and control (I&C) measures, procurement of the requisite components and parts, as well as planning and implementation of assembly and initial startup and testing.

The integration and arrangement of modifications in Concept 2 based on the systems engineering requirements, component design, and structural conditions are given in Figure 7. Further processing of these plant-specific, tailored designs is performed in a team (Figure 8) with the individual work groups and personnel.

The team leader is responsible for engineering, scheduling, and costs for the entire project as defined by corporate guidelines. The leader is the customer contact and provides the customer with a direct personal interface with the project.

INSTALLATION AND INITIAL STARTUP AND TESTING

The critical path for plant modifications was set by the work on the PRZ system. Following plant shutdown, work proceeded immediately on disassembly of the old piping and valves and subsequent installation of the new valves and piping with supports. Following completion of electrical and I&C work, it was possible to begin initial startup and testing. Figure 9 shows the completed retrofit of the Neckar 1 PRZ valve station with insulation installed. These modifications were performed in the Neckar 1 plant over a 58-day period during the 1993 refueling outage. During peak periods, up to 250 employees from Siemens-KWU and subcontractors were employed on site for this retrofit.

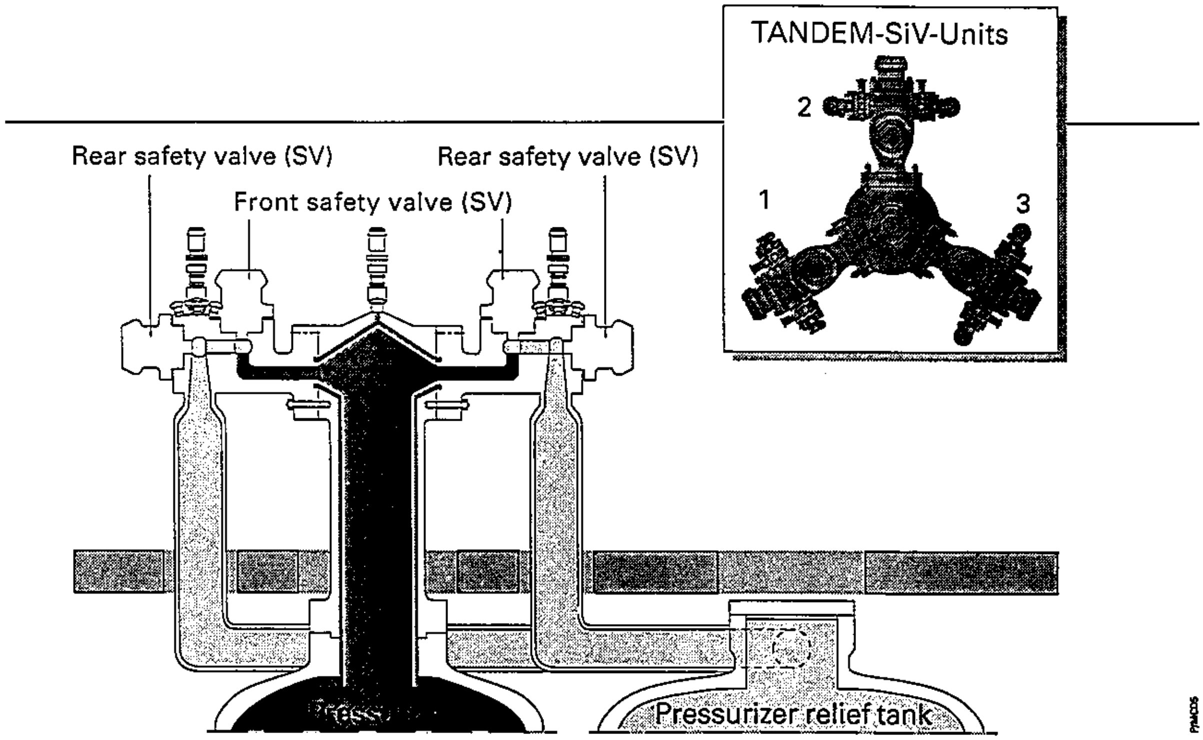

Figure 7. OLYMPUS 2000 PRZ valve station.

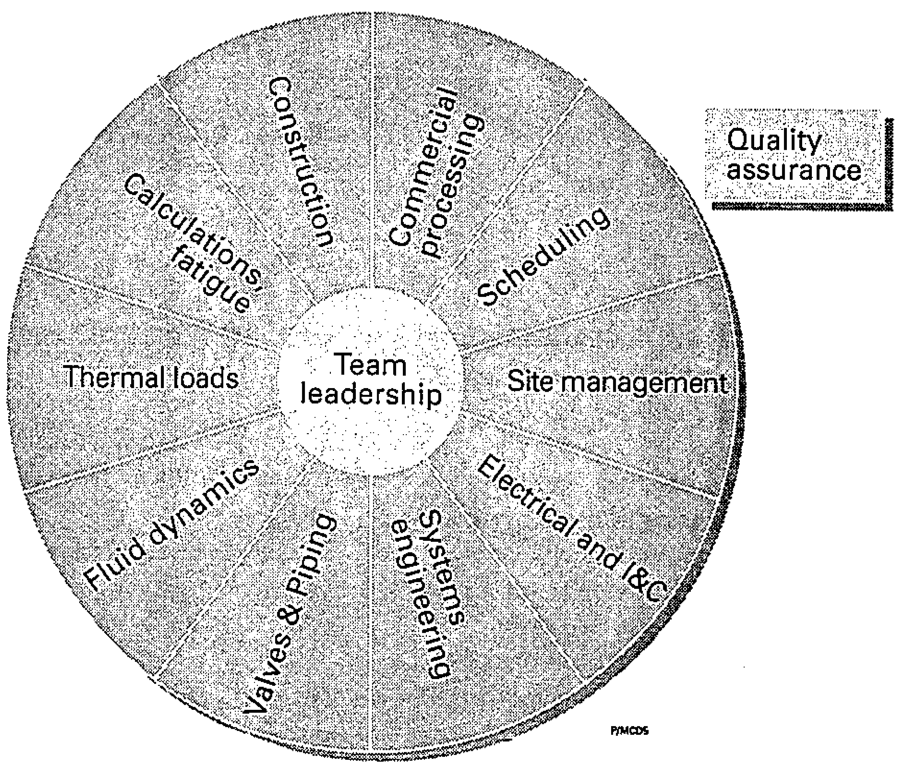

Figure 8. PRZ system refit, Neckar 1 project team.

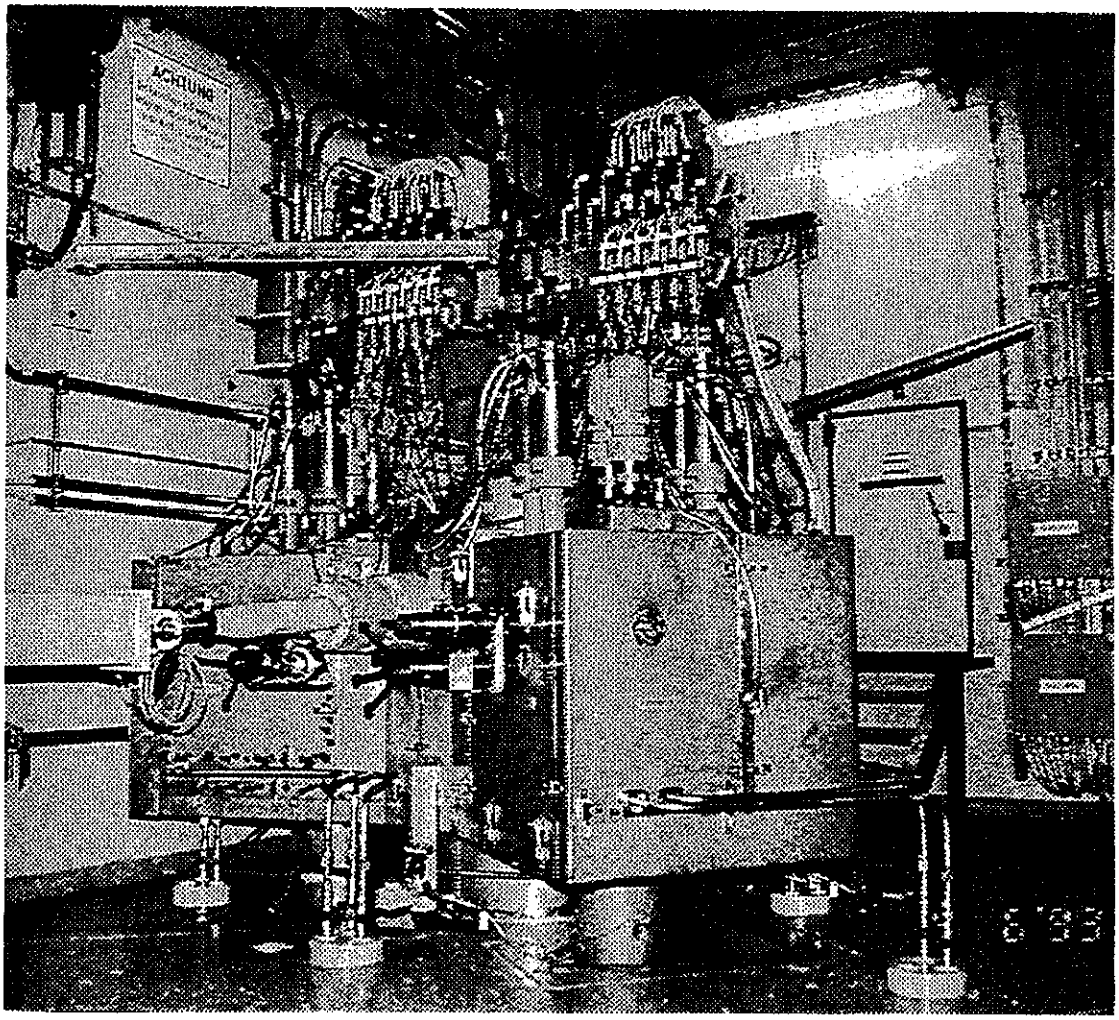

Figure 9. Neckar 1 PRZ system retrofit modifications completed.

CONCLUSIONS

This example of retrofit work is intended to give an impression of the magnitude and complexity of projects in the field of services.

Planning and execution of these measures requires a thorough understanding of basic physical and engineering principles, as well as knowledge of and experience with the particular features of the various power plants. Knowledge of how power plants respond during normal operation and operational malfunctions is also essential.

The Siemens Power Generation Group (KWU) has such knowledge available. This forms the basis for Siemens' ability to implement all types of associated measures in any nuclear power plant, independent from nuclear steam supply system architectural engineering, and on short notice.

The studies performed, especially for the new valves, proved to be an essential requirement for proper installation and initial startup and testing.

To date, the new equipment has not caused a single event in plant operation, so the retrofit can be considered an exceptional success.

The operators of power plants constructed by Siemens-KWU have backfitted their plants to improve safety while maintaining availability. These measures also contribute to the greater than 80% mean annual availability of Siemens-KWU-plants.

Cooperation—The Key to Solving Tough Valve Problems[a]

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ABSTRACT

A group of Idaho National Engineering Laboratory researchers, under the sponsorship of the U.S. Nuclear Regulatory Commission, has participated in a number of multinational research and test programs in both the U.S. and in Europe. These programs focused on motor-operated valves (MOVs) and piping systems subjected to seismic and flow loads and MOVs subjected to flow loads up to and including pipe break flow. This paper reviews these programs and their results, briefly summarizes related work done by others, including Kraftwerk Union in Germany and the Central Electricity Generating Board of the United Kingdom, and in conclusion discusses some of the current research needs. One of the purposes of this paper is to convey an understanding of the extent to which international cooperation has contributed to valve research.

INTRODUCTION

One of the challenges facing the nuclear industry in both the U.S. and other countries involved with nuclear power generation is the need to ensure that motor-operated gate valves can perform their design basis function, usually to close against specified flow and pressure loads. A long history of problems with motor-operated valves (MOVs) has provided the impetus for governments and the private sector to conduct several test programs during the past few years. The Idaho National Engineering Laboratory (INEL), under the sponsorship of the U.S. Nuclear Regulatory Commission (USNRC), has participated in gate valve research since the mid-1980s. Our valve research has included valve operability tests that were part of two international seismic test programs conducted at an experimental reactor facility operated by Kernforschungszentrum Karlsruhe (KfK) near Frankfurt, Germany; testing of two motor-operated gate valves at high pressure blowdown conditions at Wyle Laboratories in Huntsville, Alabama; more extensive testing of six valves at the Kraftwerk Union (KWU) facilities in Germany; and testing on a valve load simulator at the INEL. Testing by others includes testing to support development of new valves for the Convoy plants in Germany and valve tests conducted by Nuclear Electric (NE) at their Marchwood, England, facility and at the KWU facilities. The Electric Power Research Institute (EPRI) recently conducted a program testing more than 30 valves at facilities in both the U.S. and Germany.

Valve research conducted by the INEL and by others has identified and addressed several issues related to a valve's ability to perform its design basis function. The results of the research have prompted the nuclear industry to take a closer look at gate valve internal clearances and to reexamine the models and analytical methods that were originally used to size the operators and set the control switches for torque-controlled motor-operated

a. Work supported by the U.S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, Division of Engineering and Division of Safety Issues Resolution, under DOE Contract No. DE-AC07-76ID01570.

gate valves. In a couple of instances, new disc designs were developed. In addition, new analytical methods have been and are being developed that reflect a better understanding of gate valve operation. These issues have had the attention of the nuclear community in the U.S. and abroad, and the international scope of this valve research has provided an excellent environment for information exchange and peer review.

This paper discusses several of the important findings that are the result of this international cooperation and identifies some of the major tasks currently being reviewed by the international community.

SHAG Testing at HDR

The SHAG (Shakergebäude—building shaker) test series was an international program conducted by Kernforschungszentrum Karlsruhe. Researchers from the INEL joined other U.S. researchers from ANCO Engineers, Argonne National Laboratory (ANL), and EPRI, and German researchers from Fraunhofer Institut (LBF), Hochtief AG, KWU, and Staatliche Materialprüfungsanstalt (MPA) in participating with KfK in the test series. The tests were conducted in 1986 at HDR (Heissdampfreaktor—hot steam reactor), a decommissioned experimental facility located near Frankfurt, Germany. The results of the INEL's part in the test program are published in a NUREG/CR report (Steele et al., 1989). A summary is presented here.

Seismic qualification of nuclear equipment is typically performed to industry standards, some of which are justified by only analytical or extrapolated data. This is especially true of qualification standards for valves and line-mounted equipment (transducers and other equipment mounted on the piping), for which seismic input is always analytically determined. SHAG testing provided an opportunity to measure actual, three-dimensional loads and actual responses to a simulated earthquake, thus providing empirical data to either confirm or challenge the analytical methods used in equipment qualification standards. These tests were the first in situ experiments subjecting an entire containment building and its components, including a full-scale piping system with a motor-operated valve, to simulated earthquake loadings.

SHAG Test Description

Earthquake loadings were simulated in the HDR building by means of a large, eccentric mass, coastdown shaker installed on the upper floor of the HDR. See Figure 1. For each test, the shaker, shown in Figure 2, was weighted with a specified amount of weight bolted to the two shaker arms. With the weighted arms opposite each other, the shaker was spun up to a specified speed corresponding to the starting frequency for that test (varying from 1.6 to 8 Hz). The arms were then allowed to swing together, creating a revolving eccentric mass that shook the building as the shaker coasted down. The building and the equipment installed in the building responded in much the same way they would respond to an earthquake imparting dynamic energy to the building from the ground.

Our testing focused on the VKL (Versuchskreislauf—experimental piping loop), an existing piping system located in the VKL room, as shown in Figure 1. We modified the VKL, shown in Figure 3, by installing a naturally aged 8-in. dc-powered motor-operated gate valve and by installing snubbers, spring hangers, and struts to create a piping support system designed to be typical of U.S. nuclear installations. The configuration of the U.S. stiff support system was based on a computer analysis of the VKL and on acceptance criteria specified in the American Society of Mechanical Engineers (ASME) Code. The 8-in. gate valve was a 25-year-old valve from the decommissioned Shippingport Atomic Power Station.

We installed 103 instruments on the VKL and on the HDU (Heissdampfumformer—steam generator), a large vessel to which the VKL is attached. The instruments measured acceleration, displacement, strain, force, temperature, pressure, differential pressure, valve position, valve motor amperage, and motor voltage. We monitored the operability of the valve by opening and closing the valve during and after the simulated earthquakes, with flow, pressure, and temperature loads imposed on the valve.

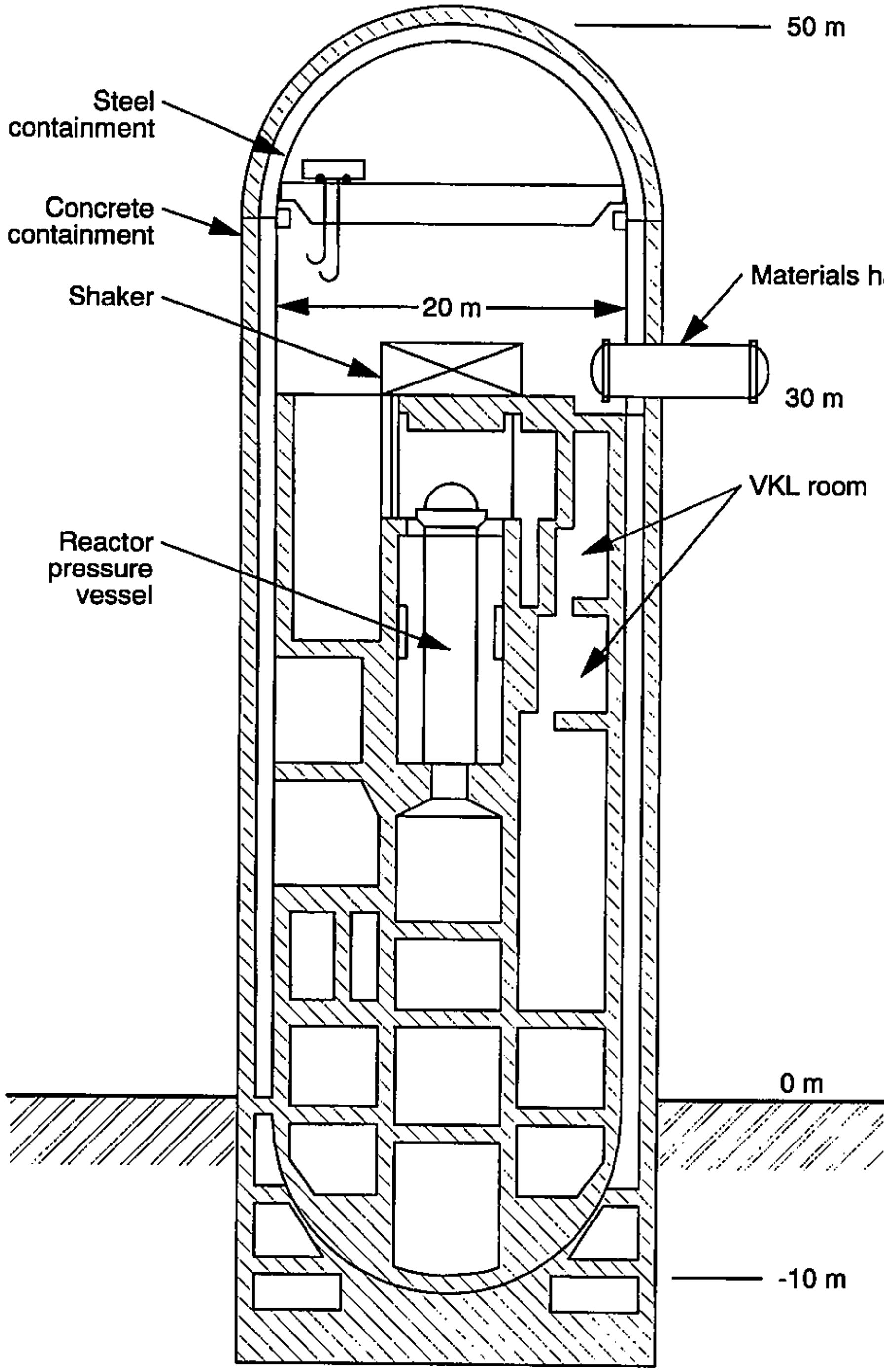

Figure 1. A simplified cross section of the HDR facility, showing the locations of the shaker, the VKL, and the reactor pressure vessel.

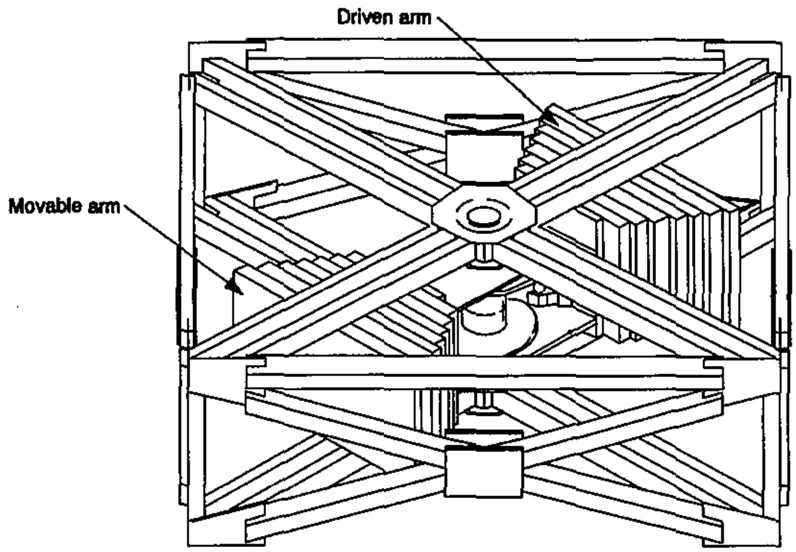

Figure 2. The large twin-arm rotary mass coastdown mechanical shaker used to produce the simulated seismic excitation.

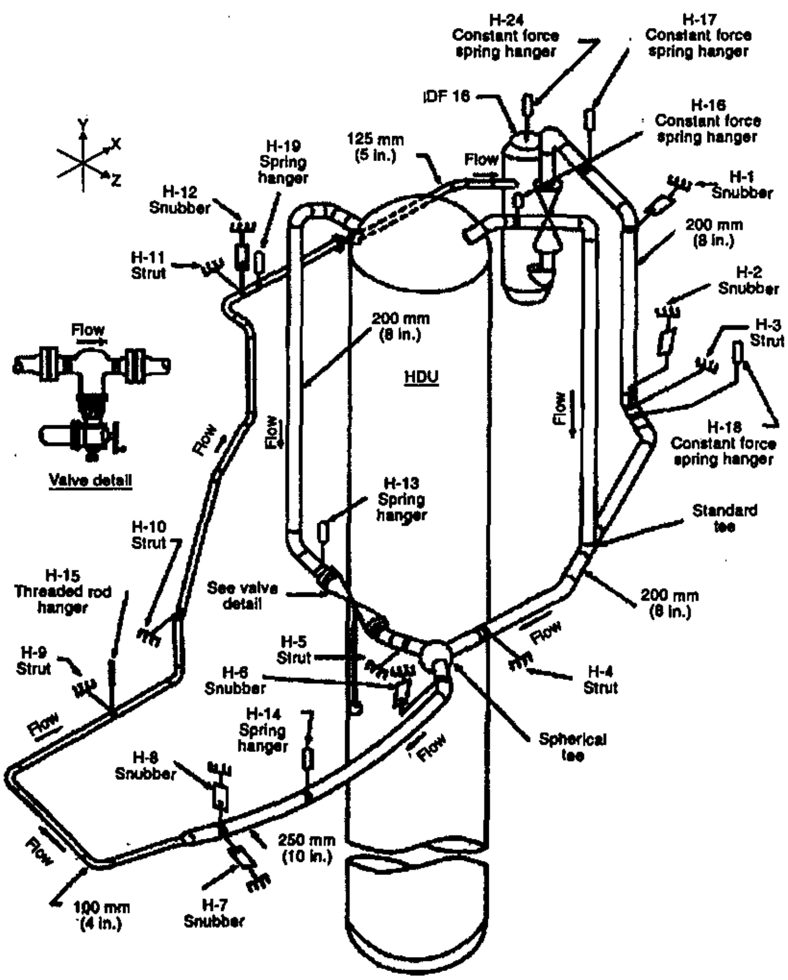

Figure 3. A schematic drawing of the VKL, showing the 8-in. motor-operated gate valve and the U.S. stiff piping support system.

Six other piping support systems sponsored by other participants were also installed at various times during the testing (see Table 1). The seven piping support systems used different combinations of various kinds of supports to represent piping systems ranging from stiff to very flexible. The VKL's dynamic response was monitored with each of the support systems installed so that the results could be evaluated. In all, 25 tests were run, with eight tests at 8 Hz, six tests at 6 Hz, and the others at lower frequencies. Seven of the 25 tests were conducted with the U.S. stiff support system installed.

SHAG Test Results

The actual forces applied to the building in the frequencies of interest for piping and valve research (6 and 8 Hz) met the requirements of the SHAG test program. Zero period accelerations (ZPAs) as high as 0.3 g were input to the HDU vessel and the piping system supports. The VKL responded not only to input from the building through the supports, but also to even greater input from the HDU vessel through the piping connected to the top of the vessel. The acceleration responses of the piping averaged 1 to 3 g throughout the VKL. Some of the snubbers experienced loads approaching their ASME Code Level C allowables. Struts experienced loads of up to 11,000 lb force.

SHAG testing at HDR verified that structurally, valves and piping are inherently tough. The structural integrity of the valve and piping was not compromised by the seismic loads. None of the seven piping support systems' responses resulted in piping strain measurements that reached 50% of yield. These results indicate that earthquakes of credible magnitude are not likely to cause structural failure of valves or piping in piping systems designed according to methods commonly used in the nuclear industry.

The U.S. stiff system used six snubbers and six struts. All of the snubbers and struts functioned properly except for one brief instance (3 to 4 sec) where one mechanical snubber temporarily failed to lock up. The anomaly was self correcting.

Table 1. Type of supports used in the SHAG test series.

Support system	System number[a]	Struts	Snubbers	Viscous mass supports	Impact supports	Flexure supports
U.S. stiff	3	6	6[b]	0	0	0
KfK very flexible	1	2	0	0	0	0
KWU flexible	2	5	0	0	0	0
EPRI/Cloud impacting	5	6	0	0	6	0
EPRI/Bechtel energy-absorbing	4	6	0	0	0	4
GERB energy-absorbing	6	5	0	2	0	0
ANCO energy-absorbing	7	6	0	6	0	0

a. We have retained the numbers chosen by KfK in order to facilitate cross-referencing among reports.

b. Five mechanical snubbers and one hydraulic snubber.

The philosophy reflected in the stiffness of the U.S. stiff system is to avoid amplification and reduce resonant response by stiffening the piping system so that the natural frequencies in the piping are higher than the frequencies at which the building responds to an earthquake. The U.S. stiff system performed as designed, raising the resonant frequency of the piping system. In general, the U.S. stiff system and the KfK very flexible system enveloped the response of the VKL. As expected, the stresses in the stiff system were lower than in the KfK very flexible system, but the differences were not as great as we expected. The moderately flexible KWU support system, with only half as many supports as the U.S. stiff design, responded with fewer high-peak responses and a smaller total system stress than any of the other systems. These results support the *time at frequency* argument: the more flexible a system is, the longer it takes for the system to respond to seismic input. The results are also consistent with current U.S. industry thinking that the best design lies somewhere between stiff and flexible.

Operability of the motor-operated valve was not adversely affected by the seismic loadings. However, analysis of the data revealed anomalous performance not related to the seismic loadings. During several of the functional flow tests, the torque switch in the motor operator tripped before the valve had fully seated, an indication that the torque switch was not set high enough. In other instances, the motor failed to produce enough torque to trip the torque switch, and the motor stalled.

An extensive investigation ensued to discover the cause of the anomalous performance. The investigation included additional in situ testing at HDR with various flow and pressure loads, dynamometer testing of the motor operator, inspection of the torque spring, dynamometer testing of the electric motor, and an analysis of the HDR circuit that supplied power to the motor operator during the tests. The investigation produced three findings, one that relates to motor operated valves in general, and two that relate specifically to dc-powered motor-operated valves:

1. The aged torque switch spring in the operator had taken a 1/2 in. permanent set, making it necessary to increase the torque switch from a setting of 3 to a setting of 3.75 to achieve the specified torque at torque switch trip.

2. Resistance due to heating in the dc motor degraded the motor's performance, especially at higher loads. Heating incurred during a given test run affected the motor's performance in subsequent test runs if the motor windings did not have a chance to cool between runs.

3. Resistance in the circuit supplying power to the motor operator at HDR likewise degraded the performance of the motor at high currents. Even though the circuit at HDR was typical of circuits for this application in some U.S. nuclear power plants, the circuit was not adequate when the motor drew higher currents at higher loads. The configuration of the circuit with its four power cable runs made it difficult to instantaneously measure the total voltage drop across the circuit. Thus, one of the main causes of the motor operator's anomalous performance, undersized cables in the power circuit, was difficult to diagnose.

Torque spring aging, motor heating, and undersized power cables can adversely affect the performance of motor-operated valves in nuclear power plants. The investigation that followed the anomalous performance of the valve at HDR led to the solution of an undersized dc power cable problem that appeared as burned out motors in several U.S. nuclear power plants. This issue (undersized dc power cables) was addressed in NRC Information Notices 89-11 and 88-72. Conventional in-plant testing with no loads or with static pressure loads alone cannot detect potential deficiencies caused by motor heating or undersized cables. Torque spring aging was addressed in NRC Information Notice 89-43.

HDR seismic test results indicated an unexpectedly large high-frequency response in the valve assembly. High frequency accelerations were amplified from the valve body to the valve operator in the 33 to 50 Hz range. This high frequency response is not peculiar to the SHAG test series. A similar response was observed in an earlier seismic test program (Close et al., 1986). Results from that test program were compared with the results from the SHAG tests to confirm the occurrence of this high frequency response. The concern with the high frequency response is that most seismic qualification standards do not account for frequencies above 33 to 40 Hz. This is not a structural problem, but a functional concern: the high frequency response might affect valve operation by causing switches, relays, and other valve control devices to chatter. However, no such malfunctions occurred during the SHAG testing.

SHAM Testing at HDR

Following the SHAG seismic tests described above, another international seismic research program, the SHAM (Servohydraulische Anregung Maschinetechnik) test series, was conducted in 1988 at HDR. Joining KfK in this effort were researchers from INEL, ANL, EPRI, KWU, LBF, and the Central Electricity Generating Board (CEGB) of the United Kingdom. The results of the INEL's part in the test program are reported in report NUREG/CR-5646 (Steele and Nitzel, 1992). A summary is presented here.

The SHAM test series provided additional information on the issues addressed by the SHAG test series. Specifically, the SHAM tests were designed to impose even higher earthquake-like loads on the valve and on the VKL, with the following objectives: (a) determine the increased seismic load effects on valve operability and valve and piping structural integrity, (b) determine safety margins and failure modes of piping supports (snubbers, struts, etc.), (c) determine the effects of single and multiple support failures on the response of the piping system, and (d) provide data so that the performance of the various piping support systems could be evaluated.

SHAM Test Description

The SHAM test program used two large 40-ton servohydraulic shakers, each mounted with one end attached to the structure of the HDR building and the other end attached to the VKL. The shakers provided input motion to the VKL at locations H-5 and H-25, as shown in Figure 4. Earthquake-like displacement histories were input to the shakers to produce input zero period accelerations ranging from 0.6 g in the 100% (nominal) safe shutdown earthquake (SSE) tests to 4.8 g in the 800% SSE (nominal) tests. In all, 51 experiments were conducted, with six different piping support systems varying from stiff to very flexible installed on the VKL during different segments of the test series. Table 2 lists the supports used in each of the six support systems. Nine of the tests were conducted with the U.S. stiff support system installed. Table 3 presents the test matrix for those nine tests and three pretest runs. Figure 4 shows the VKL as modified for the SHAM tests and shows the locations of the shakers and the supports, as configured for the U.S. stiff support system. As in the earlier SHAG tests, computer analysis and the ASME Code were used in the design of the support system.

The instrumentation system included over 300 instruments to measure acceleration, displacement, strain, force, fluid pressure, valve stem position, valve motor current and voltage, and other parameters. As in the earlier SHAG testing, the performance of the valve was monitored with the valve operating during the simulated earthquakes. For the SHAM tests, however, the valve's motor operator was powered by an ac motor instead of the dc motor used in the SHAG testing.

SHAM Test Results

The ac-powered motor-operated gate valve performed smoothly during all the SHAM seismic tests. The valve body sustained accelerations as high as 7 g in the 800% SSE test, and the valve operator sustained accelerations as high as 12 g, without adverse effect. As in the SHAG testing, an amplified response was measured in the valve operator at frequencies higher than those at which

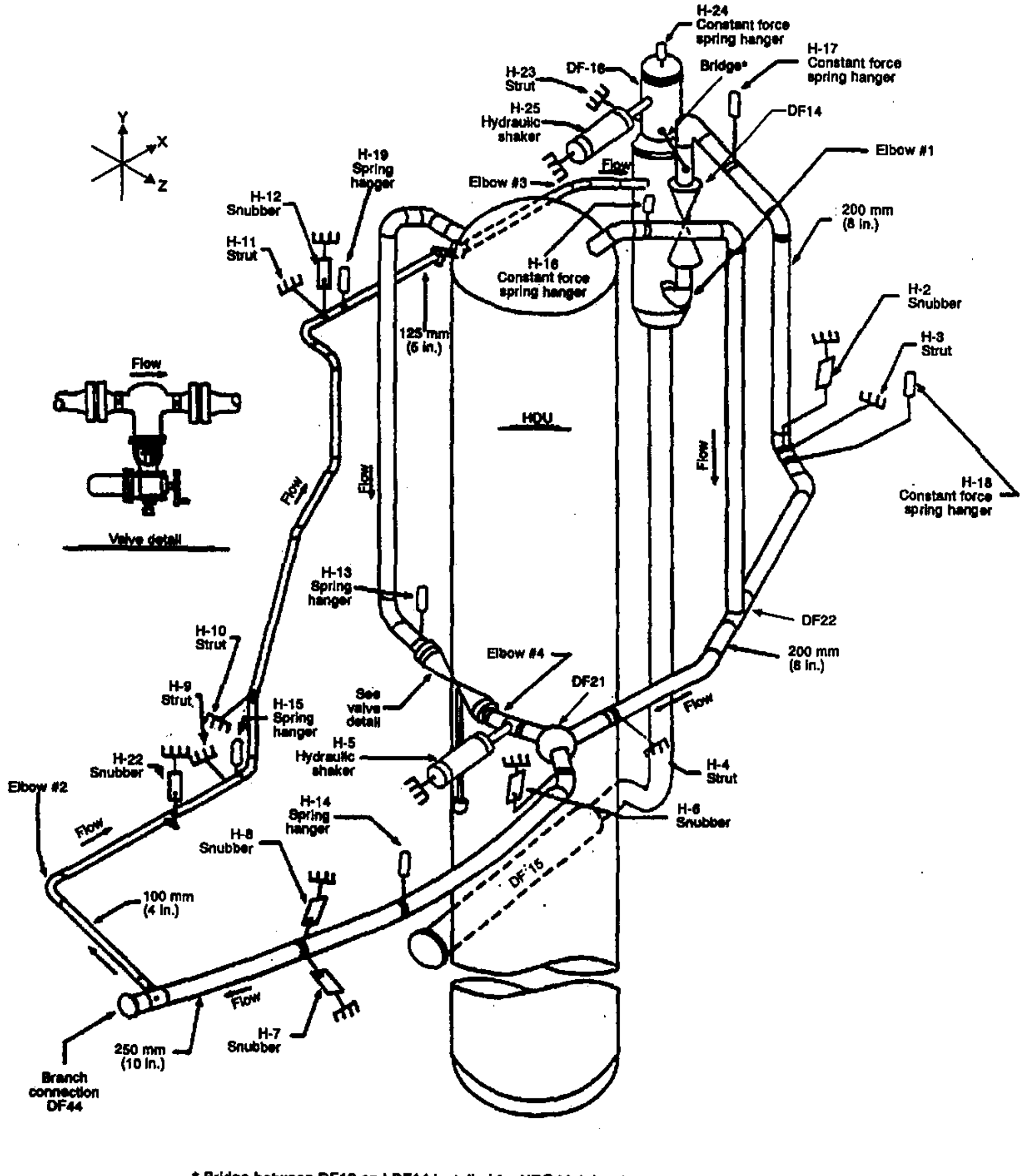

Figure 4. A schematic drawing of the VKL, as configured for the SHAM tests.

Table 2. Participants' support configurations for the SHAM test series.[a]

Support number	KfK	KWU	U.S.	EPRI/ Bechtel	EPRI/ Cloud	CEGB
H-2	—	—	S	—	SS	—
H-3	—	—	RS	RS	RS	—
H-4	RS	RS	RS	RS	RS	RS
H-5	HS	HS	HS	HS	HS	HS
H-6	—	—	S	—	SS	—
H-7	—	—	S	EA	SS	RS
H-8	—	—	S	EA	SS	RS
H-9	—	RS	RS	RS	RS	RS
H-10	—	RS	RS	RS	RS	—
H-11	—	RS	RS	RS	RS	—
H-12	—	—	S	—	SS	RS
H-22	—	—	S	EA	SS	—
H-23	RS	RS	RS	RS	RS	RS
H-25	HS	HS	HS	HS	HS	HS

a. S = snubber, RS = rigid strut, HS = hydraulic shaker, EA = energy absorber, SS = seismic top.

Table 3. U.S. stiff support system test matrix.

Test number	Load type	Load level
T41.35.2	Checkout	0.2g
T41.30.2	Random	0.3g
T41.30.1	Random	0.3g
T41.31.0	SSE	100% SSE[a]
T41.31.1	SSE	100% SSE
T41.31.2	SSE	100% SSE
T41.31.3	SSE	200% SSE
T41.31.4	SSE	300% SSE[b]
T41.31.5	SSE	300% SSE
T41.81.1	SSE	200% SSE
T41.81.2	SSE	600% SSE
T41.81.3	SSE	800% SSE

a. 100% SSE = 0.6g ZPA input.

b. Incomplete test, malfunction of test equipment.

typical valve assemblies are qualified. Some contact chatter occurred in the switches in the motor operator, but the chatter durations were not long enough to influence the operation of the motor. No visible structural damage occurred to the valve or the operator.

One of the objectives of the SHAM testing was to determine the loads at which snubbers and other dynamic piping supports would fail. The investigation also considered some of the more common devices for attaching piping supports to the building structure and to the piping. Among these were piping trunnion attachments and concrete anchors. None of the trunnion attachments failed. Some concrete anchors loosened somewhat, but no failures occurred. Even with loads as high as five times their rated loadings, no rigid struts failed.

Several snubber failures occurred. In most instances, snubber failures occurred at loads well above their rated loadings. However, two snubbers of the same make and model failed at the H-7 location at loadings lower than their rated loading. Table 4 presents a list of which snubbers were installed at the six snubber locations during the twelve test runs conducted with the U.S. support configuration installed and provides

Table 4. Snubber installation matrix for U.S. stiff support system.

	Snubber installed[a]					
Test No.	H-2	H-6	H-7	H-8	H-22	H-12
T41.35.2	PSA-1	PSA-1/2	A/D 150[b]	A/D 70	PSA-1/4	A/D 40
T41.30.2	PSA-1	PSA-1/2	A/D 150[c]	A/D 70	PSA-1/4	A/D 40
T41.30.1	PSA-1	PSA-1/2	A/D 150[c]	A/D 70	PSA-1/4	A/D 40
T41.31.0	PSA-1	PSA-1/2	A/D 150[d]	A/D 70	PSA-1/4	A/D 40
T41.31.1	PSA-1	PSA-1/2	A/D 150[c]	A/D 70[b]	PSA-1/4[b]	A/D 40
T41.31.2	PSA-1	PSA-1/2[b]	PSA-1	PSA-1/2	PSA-1/4[c]	PSA-1/4
T41.31.3	PSA-1	PSA-1/2[c]	PSA-1	PSA-1/2[b]	PSA-1/4[c]	PSA-1/4
T41.31.4	PSA-1	PSA-1/2[c]	PSA-1	PSA-1/2[c]	PSA-1/4[c]	PSA-1/4
T41.31.5	PSA-1	PSA-1/2[c]	PSA-1	PSA-1/2[c]	PSA-1/4[c]	PSA-1/4
T41.81.1	PSA-1	PSA-1	PSA-1	PSA-1	PSA-1	PSA-1
T41.81.2	PSA-1	PSA-1	PSA-1	A/D 70[b]	PSA-1/4[b]	A/D 40[b]
T41.81.3	PSA-1	PSA-1	PSA-1[b]	A/D 70[c]	—[e]	A/D 40[c]

a. PSA denotes a snubber provided by the Pacific Scientific Corporation, while A/D denotes a snubber provided by Anchor/Darling Industries.

b. Snubber failed during this test.

c. Snubber was left in place but failed during a previous test.

d. Snubber was replaced for this test and failed during this test.

e. Snubber was removed; it failed during the previous test.

information on snubber failures. One snubber, installed at H-22, experienced a "rigid mode" failure; though it allowed excessive motion, it also resisted some force. The other snubber failures consisted of internal damage that allowed excessive motion without resistive behavior. Where snubber failures did not occur, snubbers successfully performed their design function, keeping displacements to a minimum. In most cases, snubbers resisted loads several times their rated loadings without failure. One snubber resisted loads more than eight times its rated loading before it failed. Table 5 provides information on some of the loads resisted by some of the snubbers.

One of the concerns addressed in seismic probabilistic risk assessments is the possibility that failure of a support during an earthquake would cause higher loads to be imposed on a nearby support, causing it, too, to fail. Failure of a second support would in turn cause a third support to fail, and so on. This phenomenon, known as the zipper effect, occurred during the 600% SSE test, during which three snubbers failed one after the other. A

Table 5. Maximum loads for struts and snubbers installed in the U.S. stiff support system.

		Predicted vs. measured loads (KIP)[a]		Rated vs. measured loads (KIP)[a]		
Support location	Support type[b]	Predicted for 200% SSE test[c]	Measured in test 81.1 (200 SSE test)	Rated[d]	Measured in test 81.2 (600 SSE test)	Measured in test 81.3 (800 SSE test)
H-2	S	2.61	−1.69	2.10	5.04	4.73
H-3	RS	3.05	3.47	2.10	10.3	13.5
H-4	RS	3.57	NA	24.73	NA	NA
H-6	S	1.27	1.36	2.10	5.64	9.17
H-7	S	1.80	4.19	2.10	9.75	−26.4[e]
H-8	S	0.85	−1.32	0.87	1.87[e]	NA[f]
H-9	RS	1.28	0.62	0.87	2.12	4.02
H-10	RS	0.77	0.94	0.87	−2.97	4.85
H-11	RS	1.78	1.27	0.87	−3.23	−4.36
H-12	S	0.71	0.55	0.52	1.07[e]	NA[f]
H-22	S	0.52	0.47	0.52	−1.75[e]	NA[f]
H-23	RS	9.09	NA	49.5	NA	NA

a. To calculate loads in KN, multiply by 4.448.

b. S = Snubber RS = Rigid strut.

c. Predictions based on analysis of the VKL in its modified, as-tested, configuration.

d. Service Level C maximum rated loadings for the snubbers and struts that were installed in tests 81.2 and 81.3.

e. Snubber failed during this test.

f. Snubber failed during previous test.

NA = Not applicable.

fourth snubber failed during the 800% SSE test that followed. With several of its supports out of service, the VKL became more flexible and responded at lower frequencies, especially in the Y (vertical) direction of the section that runs from the spherical tee DF21 through branch connection DF44 to the DF16 component (see Figure 4). As expected, the test data indicated that displacements and strains increased with the failures of the snubbers. Strains were measured in excess of the 0.3% value used to define yield in stainless steel, with the highest strains measured at elbows 1 and 2. Some plastic deformation occurred at these elbows, but no other structural damage occurred and no leakage occurred in any of the piping.

Test results from the SHAM test series reaffirm the structural toughness of valves and piping. When commonly accepted design methods are applied, piping systems will likely maintain their pressure boundary during a credible earthquake; sufficient safety margins exist even with severe earthquake loadings and the loss of multiple supports.

KWU Test Programs at the Large Valve Test Facility

In the early 1980s, KWU built what is probably the largest facility in the world for testing valves. Located in Karlstein, Germany, this facility was used to support the valve qualification program for the KWU Convoy plant. Testing included motor-operated gate valves and pilot-operated globe valves. Most of the results of those test programs are proprietary, but some information has been published by Dr. U. Simon and others. Suffice it to say that the gate valve program contributed to KWU's understanding of disc friction effects and led to the development of a new gate valve design. The new design uses a spade-shaped disc that resists tilting when exposed to severe flow loads during closure. The KWU test facility in Karlstein also served in three of the test programs that are described later in this paper.

The Generic Safety Issue 87 Test Program

The Generic Safety Issue 87 (GSI 87) test program was conducted by INEL researchers in 1987 through 1989 in two stages, designated Phase 1 and Phase 2. The results of those tests are reported in NUREG/CR reports (Steele et al., 1990; DeWall and Steele, 1989). A summary is presented here. The purpose of the testing was to determine the ability of motor-operated gate valves installed in certain piping systems to close against high-energy design-basis loadings. For example, the turbine steam supply line of the high-pressure coolant injection (HPCI) pump communicates directly with the reactor vessel, penetrates the containment, and runs to the auxiliary building, where the HPCI turbine is located. The containment isolation valves in this line are normally open. The concern with these isolation valves is whether they would close against the large pressure and flow loads that would occur in the event of a guillotine break in the steam line outside the containment. In such an event, their failure to close could result in common-cause failures of other components in the auxiliary building that were not qualified for a harsh environment. This concern was the substance of GSI 87, "Failure of the HPCI Steam Line Without Isolation." Two additional reactor systems are applicable to the GSI 87 concern: the reactor core isolation cooling (RCIC) turbine steam supply line and the reactor water cleanup (RWCU) system supply line. (In some early plants, these systems are designated by other names, but the functions are the same.)

At the time this research program began, the qualification of containment isolation gate valves for high-energy flow interruption was not well understood. The valve manufacturers and utilities all used basically the same equations to determine a valve's operator torque and stem force requirements, but there were inconsistencies in how some of the important variables in the equations were determined. The disc load portion of the stem force equation was basically the disc area multiplied by the differential pressure across the disc multiplied by a disc factor, typically 0.3.

However, there were no standards on either the disc area term or the disc factor. Some vendors and utilities used the valve orifice area to define the disc area, while others used the nominal pipe size. Similarly, some vendors and utilities used a disc factor of 0.3 (at least until the late 1980s), while others used a disc factor as high as 0.5. In any case, the disc factor was analytically based and loosely associated with a friction factor. We could find no record of full-scale flow interruption testing having been performed to support the use of a disc factor of 0.3 to determine the stem force requirements of valves installed in GSI 87 applications.

Phase 1 Tests

Our first GSI 87 valve test program was performed in the U.S. Two 6-in. RWCU valves, designated Valve A and Valve B, were subjected to testing at design-basis conditions at the Wyle Test Laboratories in Huntsville, Alabama. Researchers from CEGB and engineers from Limitorque observed the test program, and all the leading diagnostic vendors monitored some of the valve testing. A unique feature of the valve test program was that both valves were fitted with inline load cells built into their stems. This feature made it possible to directly measure stem thrust during the entire stroke.

The test results showed that predictions based on the industry stem force equation do not always bound the valves' design-basis requirements. Figure 5 shows a stem thrust history from the testing of Valve B at design-basis conditions. This response is the typical, expected response, with the peak thrust (before seating) occurring at the plateau that indicates flow isolation, when the disc is riding on the valve seat. Figure 5 also shows the stem force values that would be predicted by the industry stem force equation for those operating conditions (using the orifice area for the disc area and using the actual test pressure conditions as input to the equation, with both a 0.3 and a 0.5 disc factor). Note that at the point of interest (flow isolation), the measured stem thrust is not bounded by the prediction with the 0.3 disc factor, and is bounded by the more conservative prediction (0.5 disc factor) with very little margin.

We also found that one of the two valve designs we tested was susceptible to internal damage when exposed to the design basis flow interruption load. This internal galling, shearing of material, and plastic deformation could not be predicted by any linear friction equation.

Phase 2 Tests

The nuclear industry was reluctant to accept the results because the two-valve sample was too small to form a basis for such far-reaching implications. A second full-scale test program (designated Phase 2) followed, with three 6-in. valves subjected to parametric pressure tests and flow interruption and flow initiation tests at flows including line-break flows, with both high-energy water and high-energy steam (to cover the RWCU and the RCIC concerns), and with three 10-in. valves subjected to the same flow interruption and flow initiation tests, but with high-energy steam only (to cover the HPCI concerns). The valves were designated Valves 1 through 6.

Testing the HPCI steam valves at design basis loads required a larger facility than any existing in the U.S at that time, so the Phase 2 test program was performed at the KWU facility in Karlstein, Germany. Joining us at KWU were observers from all over Europe, diagnostic vendors from the U.S. and Germany, and observers from EPRI and the USNRC. Local support was also obtained from personnel at the neighboring HDR facility (described earlier in this paper).

In response to the lessons we learned from the Phase 1 test program, we developed a new portable data acquisition system for the Phase 2 testing. We also developed a new valve internal measurement scheme. Both of these improvements exceeded our expectations as to how much information we could obtain from the tests. This new technology later served as the basis for the acquisition and measurement scheme used by EPRI and others in their follow-on test programs.

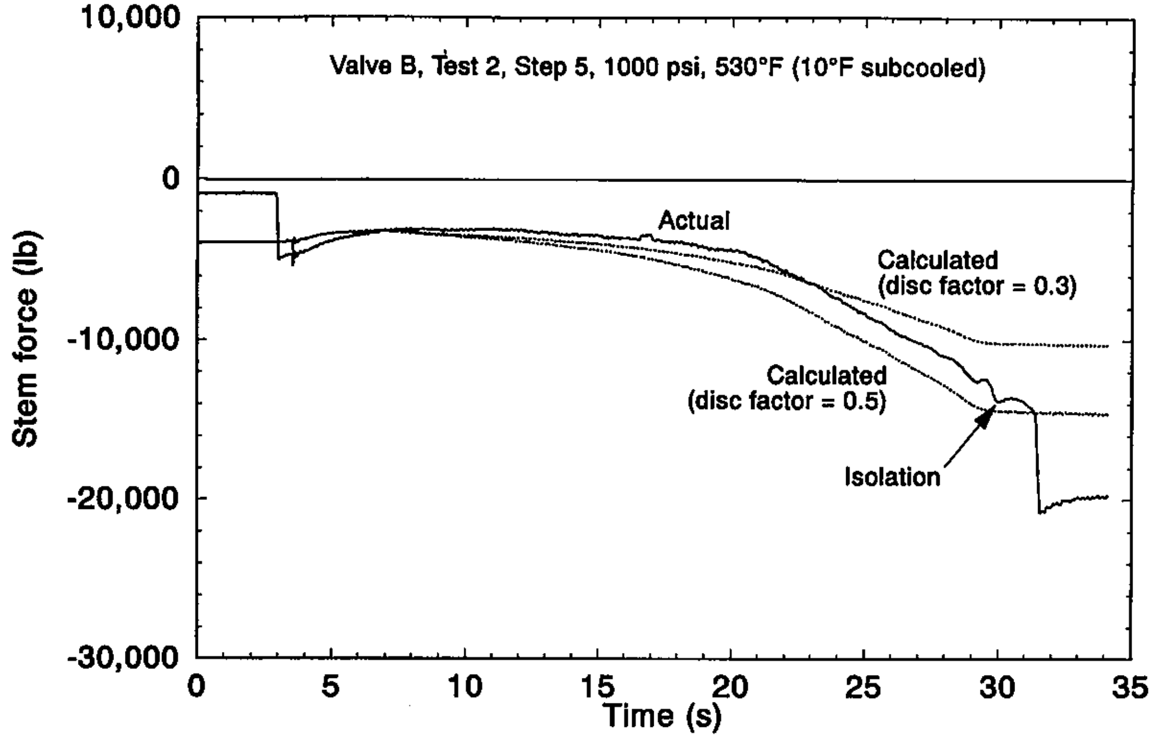

Figure 5. Stem force history recorded during a closing test of Valve B in the Phase 1 test program.

The results of the Phase 2 test program confirmed the results of the Phase 1 test program and confirmed that the industry stem force equation did not adequately characterize valve behavior and did not conservatively bound valve requirements.

As in the Phase 1 tests, we found that some valves experienced damage when closing against high-energy design-basis flow loads. The damage was indicated by a jagged stem thrust trace and an unexpected peak in the stem thrust well before flow isolation, as shown in Figure 6. Note that the peak stem thrust is higher than would have been predicted by any version of the standard industry sizing equation, even with the most conservative disc factor (0.5) in use at that time. In all of the valves that we tested that showed this unexpected peak before flow isolation, posttest inspections confirmed that damage had occurred, so we assumed that the early peak was always associated with valve damage. Later testing by others, including EPRI (see discussion below), showed that this assumption was incorrect.

We also found that contrary to the assumption widely held in the nuclear industry, the load at flow initiation is not always the highest loading in the opening direction. Figure 7 shows the results of a test in which the load at about 20% open was significantly higher than the load at start of flow. For comparison purposes, Figure 8 shows the results from an opening test with the expected response (peak opening thrust at or near flow initiation). Today, some 5 years later, valve researchers are still trying to determine what causes the load scenario shown in Figure 7.

Analysis of the Phase 1 and 2 test data led us to a new closing stem force equation along with a correlation from the data. The equation and correlation together constitute a new method for analytically determining valve closure requirements (assuming no valve damage and a peak thrust at flow isolation). The method is especially important for valves that cannot be tested in the plant at design-basis conditions. The new method was reviewed by the national and international

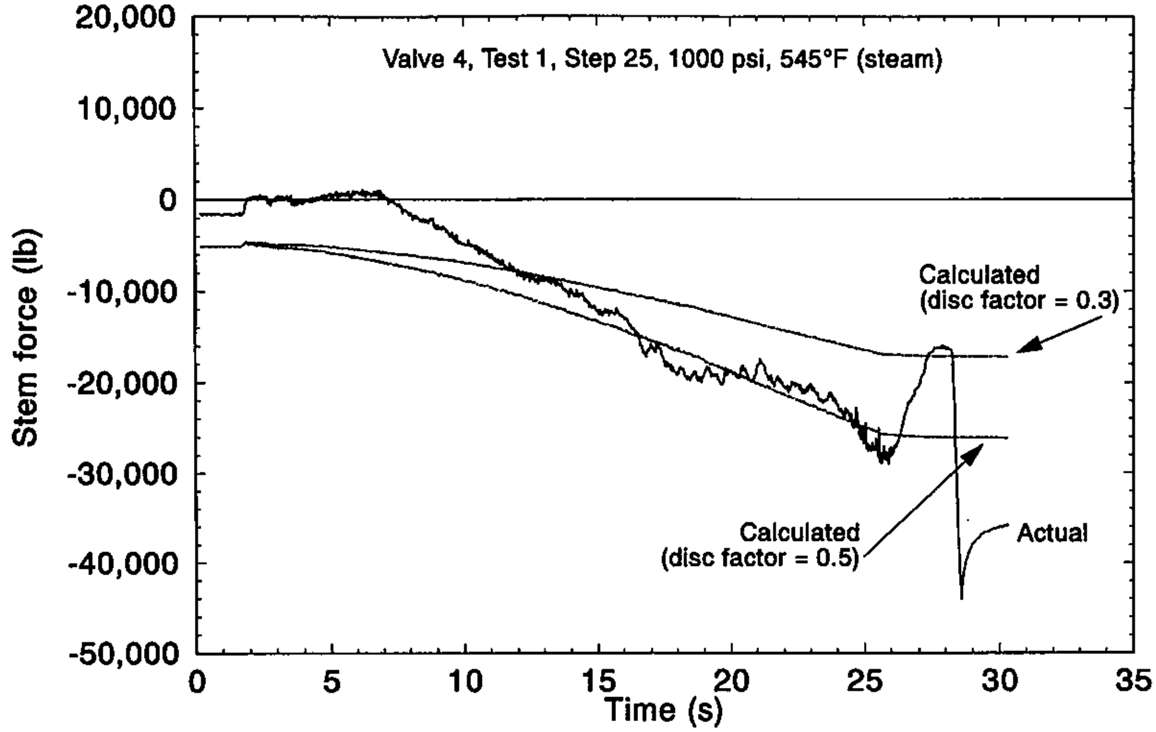

Figure 6. Stem force history from a Phase 2 test in which valve damage occurred during closure.

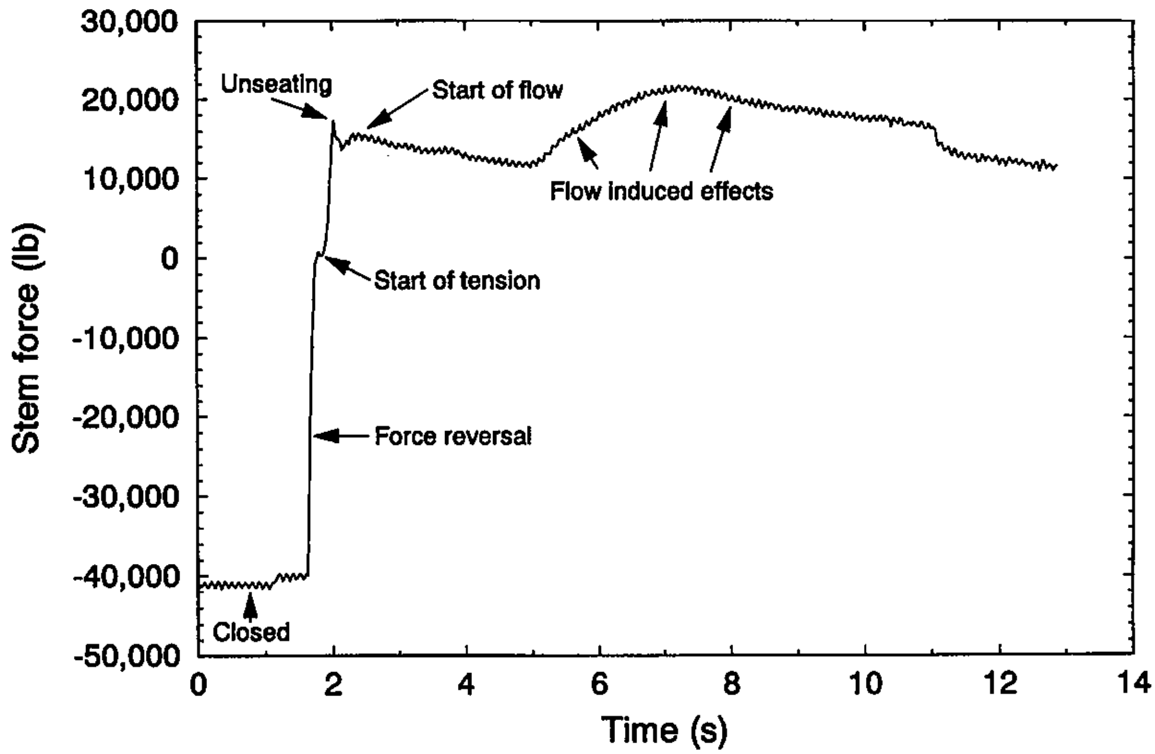

Figure 7. Stem force history from an opening test in which the load at flow initiation was not the highest load.

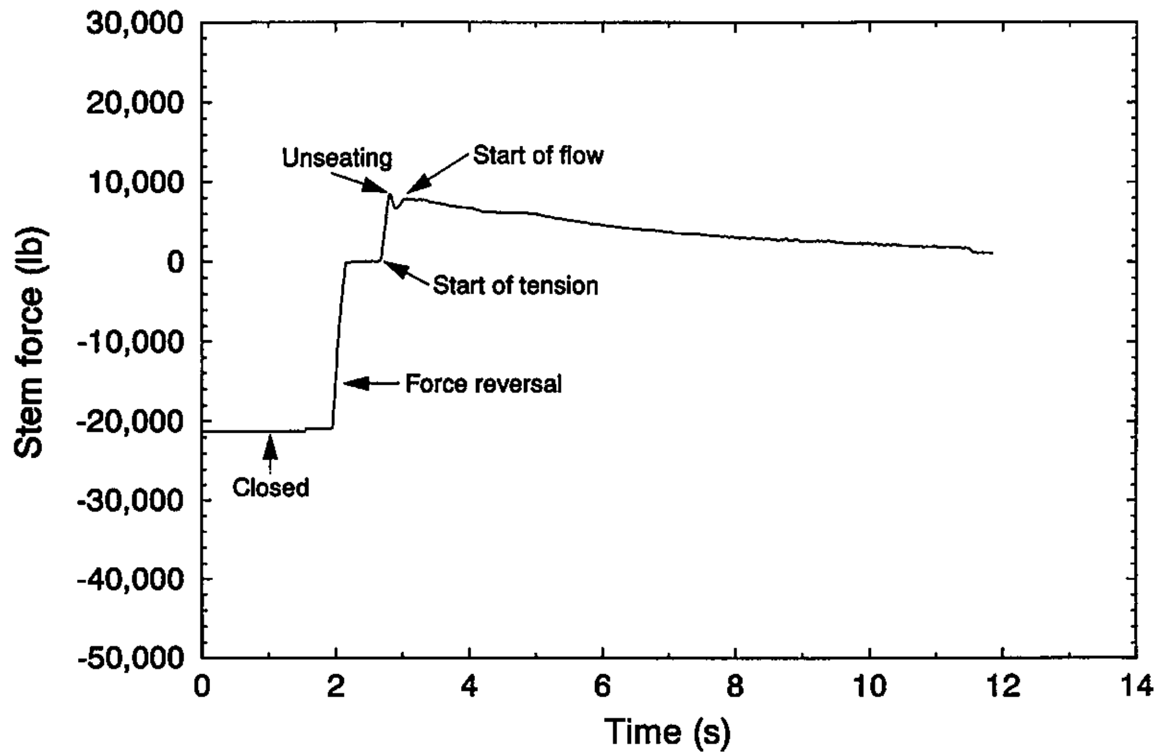

Figure 8. Stem force history from an opening test with the expected response; the load at flow initiation is the highest load. (The spike at unseating indicates the hammer blow.)

communities. The review by KWU was especially helpful because of their experience in gate valve work for the Convoy plants (mentioned previously). The INEL and KWU still disagree on whether there is a fluid quality effect or a fluid temperature effect. (The INEL method uses one of two disc friction factors, depending on the degree of subcooling of the fluid; the KWU method makes a similar distinction based on fluid temperature.) However, the result is the same for nuclear service: the hotter fluids result in less valve stem thrust during closure than the colder fluids, where all other functional parameters are the same.

The USNRC issued a number of information notices as the research results were being analyzed, and because of this work and other regulatory initiatives, the USNRC issued Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance." The generic letter recommends that the utilities reanalyze the design-basis conditions for each safety-related motor-operated valve, ensure that the operator control switches are set high enough to perform the design-basis function, and, where possible, test the valve at design-basis conditions to ensure operability.

During the GSI 87 test program, we built an MOV load simulator (MOVLS) to validate our data acquisition equipment and valve instrumentation schemes. After the GSI 87 testing was complete, we improved the MOVLS and used it to study MOV load-sensitive behavior (sometimes referred to as the rate-of-loading effect). Load-sensitive behavior appeared during our GSI 87 test program, where the same valve set at the same torque switch setting produced higher stem thrust at torque switch trip in a low load test (sometimes called a static test) than in a high load test (a test with flow and pressure loadings). We have determined that this behavior is caused by a variation in the coefficient of friction component of the stem factor equation. The stem factor issue is the subject of another paper in this symposium, so it is not discussed at length here.

Testing of Diagnostic Equipment at the INEL

By 1992, the MOV diagnostic test instrumentation industry was growing by leaps and bounds because of the added emphasis on in situ valve testing. Vendors of diagnostic equipment were making claims about the capabilities of their equipment, and in some cases the claims were not well substantiated. The MOV Users Group (MUG) asked the USNRC to cooperate in an international program to validate MOV diagnostic equipment against the vendors' claims. The USNRC agreed and made the INEL's MOVLS available to the MUG for testing the diagnostic equipment. Each vendor was allowed one week to test his equipment on the MOVLS. Because the MOVLS was already equipped with calibrated instruments (calibration traceable to U.S. National Institute of Standards and Technology) to measure all the important parameters (stem thrust, operator torque, spring pack displacement, spring pack force, etc.), this testing allowed the vendors to compare their results with a reliable standard. Every major U.S. vendor and one German vendor (KWU) participated. MUG compiled the results and published a report (MUG, 1992).

CEGB Testing at KWU

Not long before the INEL's GSI 87 Phase 2 test program was conducted, CEGB conducted a flow interruption test on a 4-in. parallel disc gate valve at the KWU facilities. This test program was conducted as part of the Sizewell B valve qualification. Sizewell B is England's first pressurized water reactor. The 4-in. valve failed to close; the disc and seat experienced damage because of the high flow load. In response to these results, CEGB had the Sizewell valve redesigned after the KWU spade disc design. By the time the new valve designs were tested, CEGB had commissioned the Bravo test rig at their Marchwood site. The smaller Sizewell valves were then qualified at Marchwood, with very good success. CEGB's larger main steam isolation valves, also of the spade disc design, were qualified at the KWU facilities. During this time, the level of international cooperation was quite high, with CEGB in England working closely with KWU in Germany and having regular information exchanges with the INEL in the U.S., including a 2-week visit by CEGB personnel to the INEL to study diagnostic techniques. Much of CEGB's test data is proprietary, but some information on the failure of the 4-in. gate valve and on the qualification of the spade disc design has been reported at various MUG meetings in recent years. As part of the information exchange between the U.S. and England, information on the CEGB valve testing was included in NRC Information Notice 90-72.

EPRI's Valve Test Program

More recently, EPRI performed a valve test program that included testing at the Wyle Huntsville facility (Alabama, U.S.), the Wyle Norco facility (California, U.S), and the KWU facility in Germany. INEL, KWU, Wyle Laboratories, and others participated in the planning and review of the EPRI test program. Analysis of the results of those tests is underway. The EPRI test program is the subject of several other papers in this symposium, so it is not discussed at length here.

However, one important result deserves comment in the context of this paper. Several of the valves tested in the EPRI program showed an unexpected peak thrust before flow isolation (as in the INEL's GSI 87 tests), but without any detectable valve damage. Figure 9 is an example of such a stem thrust trace. Figure 10 is presented here for comparison. Several utilities have also experienced this unexpected response (like that shown in Figure 9) in some of their in situ tests, apparently without significant damage to the sealing surfaces (the valves were still leaktight after the tests). These results raise concerns about the ability to accurately predict a valve's closing requirements, because all the existing methods for making such predictions assume that the peak stem thrust (before seating) occurs at flow isolation, when the full disc area is exposed to the differential pressure and the disc is sliding on the seat, not the guides.

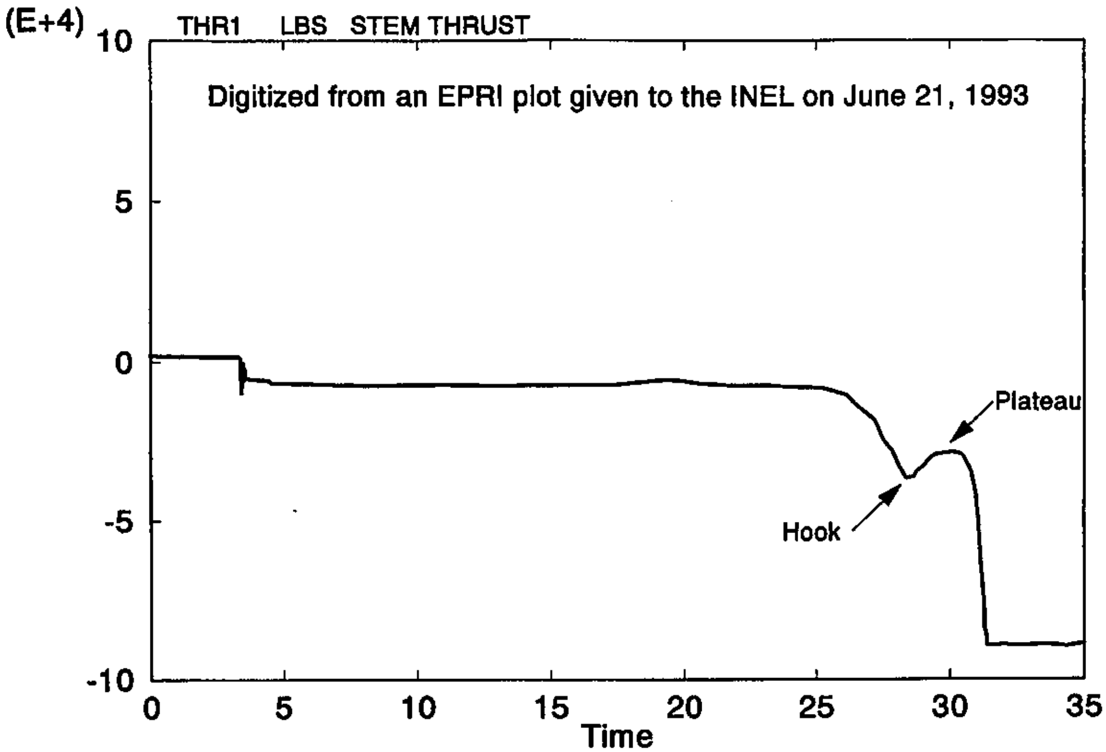

Figure 9. Stem force history from an EPRI test in which the peak thrust occurred well before flow isolation, during a closure in which no apparent valve damage occurred.

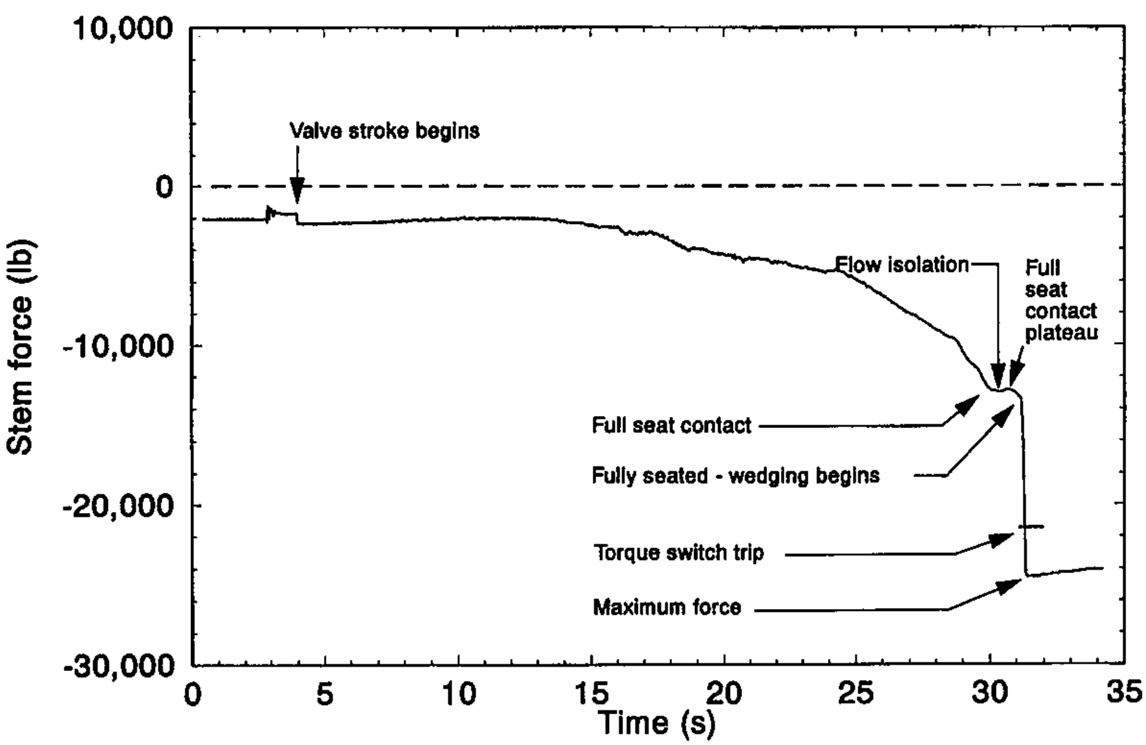

Figure 10. Classic, predictable stem force history, with the peak thrust (before seating) at flow isolation.

Other Industry Testing

The nuclear power industry (Virginia Power, Duke, and Grand Gulf, to name a few) and nuclear valve vendors (Anchor/Darling, Velan, Posi Seal, and Hopkinson, again to name a few) have performed a large amount of valve testing, mostly in support of new designs or new valves to be installed in the plants. The good news coming out of this testing is that the valves have done quite well. The valve stem loads were higher than would have been predicted some years back, but we are past that now, and most agree that the friction or disc factors are higher than the industry once thought they were.

SUMMARY

Test facilities, research organizations, and nuclear industries all over the world have provided the insights needed to solve a number of valve and motor operator problems. Seismic testing at KfK facilities in Germany alleviated concerns about the possible response of valves and other line-mounted equipment to earthquake loadings. The tests also uncovered potential problems with torque spring aging in MOVs and with motor heating and undersized power cabling in dc-powered MOVs. New gate valve designs developed in Germany in response to flow load problems found their way into a light water reactor being constructed in England. The lack of adequate test facilities in England and the U.S. was not a deterrent to those countries' test programs; KWU's Large Valve Test Facility in Germany served in both countries' test programs, and on more than one occasion. New methods for analyzing and predicting valve responses have been developed. Engineering expertise from several countries has been active in the ongoing work to solve some of the remaining major valve problems.

CONCLUSIONS

Recent valve research in the nuclear industry has been largely an international effort. The availability of expertise and facilities at KfK and KWU in Germany has been a great benefit to researchers in England and the U.S. On a number of occasions, KWU has made their senior engineering staff available for both formal and informal information exchanges. Cooperation among researchers from all three countries has sometimes been intense and has always been helpful, whether it consisted of reviewing concepts, theories, new equations, test plans, or test results, or exchanging advice and information, formally and informally.

This kind of international and domestic cooperation can help valve researchers answer the questions that still need to be answered. For example, can friction effects at the valve-stem/stem-nut interface be addressed so that the results of in situ tests conducted at low loads can be used to provide assurance that the valve will perform its design basis function? What causes some valves to experience their highest opening loads at 10 to 30% open? How can we predict those loads? What causes some valves to experience their highest closing loads before flow isolation, and how can we predict those loads? Short of redesigning and retrofitting the valves, how can we address the possibility that some valves will damage themselves when closing against their design basis loads? Under what conditions does the capability of the electric motor replace the torque switch setting as the limiting condition? There is no need for each of us to separately find answers to these questions.

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Pressure Locking of Gate Valves—French Experience and Solutions

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Marice Grenet, Electricite de France (Septen)

ABSTRACT

Pressure locking resulting from liquid entrapment affected residual heat removal suction isolation wedge gate valves in French 900-MW pressurized water reactors. Drilling of the upstream seats was insufficient to prevent overpressurization from thermal hydraulic "dead leg" effects in the upstream lines. Heating of steam condensate in the bonnet was the cause of refusal to open of the 1300-MW main steam isolation wedge gate valves. Early switch-off and incomplete closure from the stem "piston" effect on the double disk gate valves was caused by systematic leakage. Also, pressure locking from differential pressure is a concern for double-disc sump isolation valves that must be opened following a loss-of-coolant accident. Therefore, Electricite de France is now implementing a systematic program to ensure protection of gate valves against pressure locking effects by the addition of external bypass lines on sensitive gate valves that must be active during an accident.

INTRODUCTION

Many cases of pressure locking events have been reported in the U.S. literature, such as Hsu (1992). This paper presents French experience relative to those phenomena.

The first event, which involved the two residual heat removal (RHR) suction isolation wedge gate motor-operated valves (MOVs), resulted from turbulent convection heating in the upstream piping that induced overpressurization of the volume of the piping between the two valves. The second event shows that main steam isolation valves (MSIV) can be prone to the liquid entrapment effect.

The last event points out that in case of a loss-of-coolant accident (LOCA), pressure locking effects from both pressure differential and liquid entrapment may prevent the opening of sump isolation valves, which is necessary to avoid destruction of safety injection (SI) pumps. In this case, preventive measures can be complex because leak tightness is required in both directions.

Finally, the movement of the stem of double-disc parallel-seat gate valves is the cause of overpressurization in the bonnet cavity at the end of closure stroke. The disc travel can be stopped too soon by overtorquing, which later leads to leakage. This effect will be called the "piston effect."

RESIDUAL HEAT REMOVAL SHUTDOWN COOLING SUCTION ISOLATION VALVES

Initial Events and Solution

The 900-MWe French pressurized water reactors (PWRs) have two separate suction paths for RHR connected to the hot leg of Loop 2 (see Figure 1).

In Dampierre 3 in 1981, then in Saint-Laurent B1 in 1982, the two flexible 12-in. wedge gate MOVs in series (RCP 215 VP and RRA 21 VP) failed to open during reactor cooldown. The primary system (RCS) was then at 347°F (175°C) and 363 psi (2.5 MPa). Twenty-four hours later, they opened normally, with the RCS at 140°F (60°C).

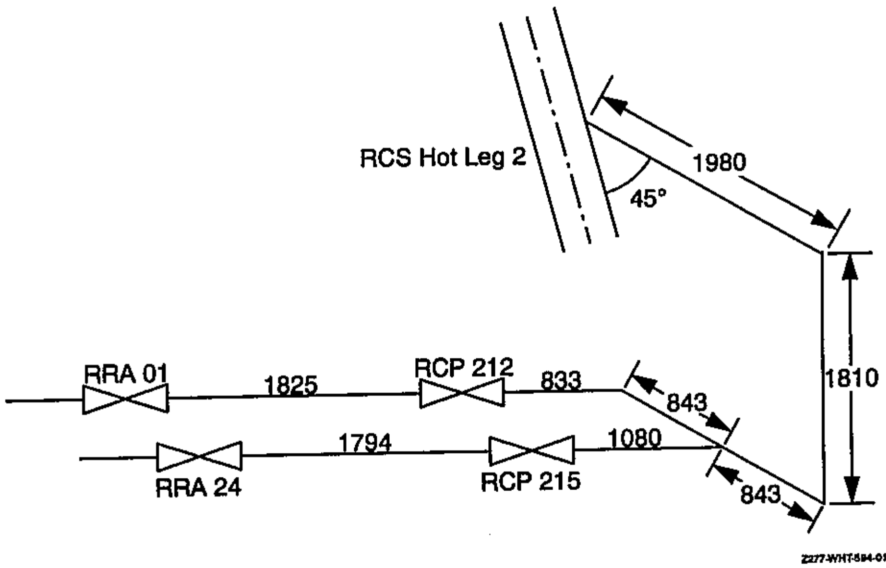

Figure 1. 900 MW RHR suction layout.

Subsequent tests in the manufacturer's shop showed, after a closure under a pressure of 435 psi (3 MPa), that the upstream disc lost its leak tightness at a pressure of about 1,015 psi (7 MPa) and that the bonnet cavity pressure increased with the upstream pressure, but did not follow the pressure as it decreased.

Nevertheless, the tested operator was able to open the valve with a differential pressure of 435 psi (3 MPa) and a pressure under the bonnet equal to the normal operating pressure of the RCS, 2175 psi (15 MPa). Indeed, the maximum running torque of the operator, not including inertia effects, was equal to more than 1,475 F(lb) (200 mdaN) and the torque switch set at 708 F(lb) (96 mdaN) was bypassed during the first part of the opening stroke.

So, as loss of tightness of the valves could not alone explain the onsite phenomena, it was assumed, without proof at that time, that either a thermal binding or liquid entrapment effect could have prevented the operators from opening the valves as a result of the high friction created between both discs and seats.

Following these incidents, a small hole (Φ = 0.24 in. [6 mm]) was drilled in the upstream seat of each valve, and since that time, no further failure to open was reported.

"Dead Leg" Effect

Because the displacements and temperatures of the RHR lines were measured during hot shutdown tests of new starting plants to be compared with theoretical values, it was found that the temperature ahead of the RHR valves was much higher than expected, considering the remoteness of the valves from the hot leg (Figure 2). Therefore, more extensive temperature recordings were made in Tricastin 1,2,3; Blayais 2; and Cruas 4. Thermocouples were placed in the invert and the crown of the 12-in. piping, just upstream of the RCS isolation valve and between the RCS and RHR isolation valves. The equilibrium temperatures for continuous operation are shown in Table 1.

It was also found that the startup of the reactor coolant pump (RCP) of Loop 2, which is connected to the RHR suction line, induced a rapid increase in temperature, the initial level being close to ambient temperature. After RCP 2 stopped, the temperature decreased immediately. Testing with removal of the piping insulation also showed the same results.

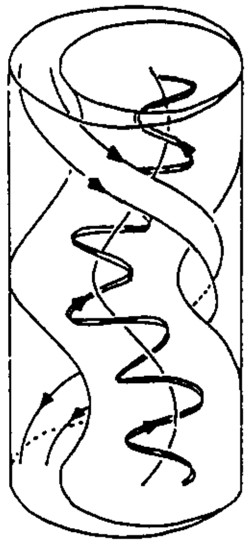

Figure 2. Schematic of the mean flow in the dead leg.

During Cruas 4 tests, pressure measurements between the two valves showed an increase up to 2,900 psi (20 MPa) during initial heatup from RHR conditions or after RCP 2 startup. The limitation to 2,900 psi (20 MPa) probably resulted from the loss of leak tightness of the downstream disc of the RCS isolation valve, and as the upstream seat was drilled, connection to the RCS at 2,248 psi (15.5 MPa).

Tests on Mock-Up

To understand these phenomena, a Plexiglass mock-up, SIERRA, at a 0.75 scale of the RHR inlet line was connected to an EDF test loop simulating the hot leg. The flow and temperature were limited to 4,400 gpm (1000 m^3/h) and 140°F (60°C), respectively. The instrumentation comprised laser velocimetry and 40 temperature probes inside the fluid.

Table 1. RHR temperatures.

	Upstream RCS valve		Between RCS and RHR valves	
Temperatures	Crown	Invert	Crown	Invert
Tricastin 2				
Nominal Power[a]				
PN = 0	482°F (250°C)	482°F (250°C)	248°F (120°C)	248°F (120°C)
PN = 100%	518°F (270°C)	518°F (270°C)	257°F (125°C)	257°F (125°C)
Blayais 2				
PN = 0	446°F (230°C)	—	248°F (120°C)	—
Cruas 4				
PN=0	500°F (260°C)	482°F (250°C)	302°F (150°C)	212°F (100°C)
PN=100%	554°F (290°C)	536°F (280°C)	347°F (175°C)	311°F (155°C)

a. Hot leg temperature: PN = 0 547°F (286°C); PN = 100% 608°F (320°C)

Caused by the shear at the branch connection, a very turbulent mixing zone occurred on a length of about three piping diameters. More unexpectedly, for high values of the Reynolds number, a complex helicoïdal movement was induced with a peripheral speed of 6% of the hot leg speed. This movement, whose rotational speed decreased with the distance from the hot leg, ensured a mixing of all the fluid in the "dead leg" up to the upstream disc of the RCS isolation valve. For low values of the hot leg Reynolds number, the mixing zone was limited by thermal stratification in the downstream part of the piping.

This phenomenon, which Robert (1992) described in detail, explains the high values of temperatures measured ahead of the RCS isolation valves and the return to ambient level once of the RCS loop pump stops.

In the horizontal pipe between the two valves, a natural convection loop, as described in Figure 3, could explain the temperature measurements.

Consequences

The consequences of high temperatures in the RHR suction lines are very different, depending upon the operating procedures. If, during plant heatup, the RCS isolation valve is closed first and then the RHR isolation valve, there will be a liquid entrapment effect and an increase of the pressure between the two valves.

This was the procedure used on 900-MW Electricite de France (EDF) plants. Therefore, the blockage of the two RHR valves in Dampierre and Saint-Laurent could have resulted from this overpressure between the two valves. One can also remark that the affected path was the one closer to the hot leg, and so more susceptible to a "dead leg" effect.

On the contrary, if the RHR isolation valve is closed first and then the RCS isolation valve, or if the valves are closed together (as was the rule in 1,300-MW EDF plants), the temperature will decrease and the fluid will shrink to about 13% of the total volume, inducing a very low pressure and a free level in the horizontal part of the piping. This shrinkage was observed and measured by ultrasonic probes at Saint-Alban, where level marks and corrosion of the base metal and stellite of the disc tracks were found on the downstream disc of the RCS isolation valve.

Prevention of Liquid Entrapment Effect Between RHR Suction Isolation Valves

At the end of 1986, EDF decided to install, on 900-MW plants, a 3/8-in. line fitted with a check valve connected to the vent holes of the valves (Figure 4). This line, in conjunction with the holes in the upstream seats, limits the pressure between the valves and in the valve bodies to the RCS pressure.

The 1300-MW RHR systems were, by construction, fitted with a line equipped with a check valve bypassing the RCS isolation valve.

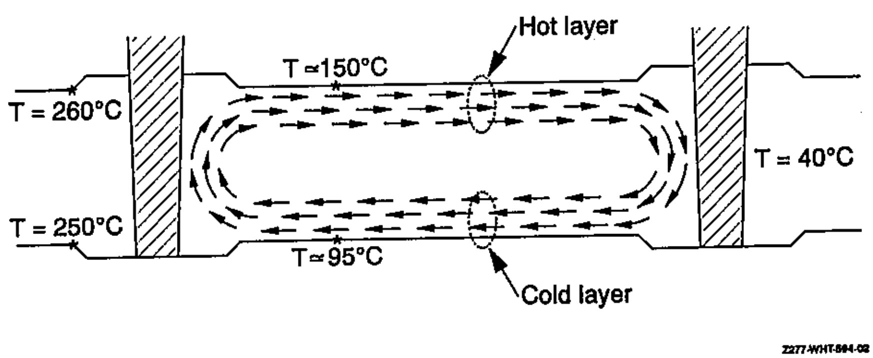

Figure 3. Natural convection loop between RHR suction valves.

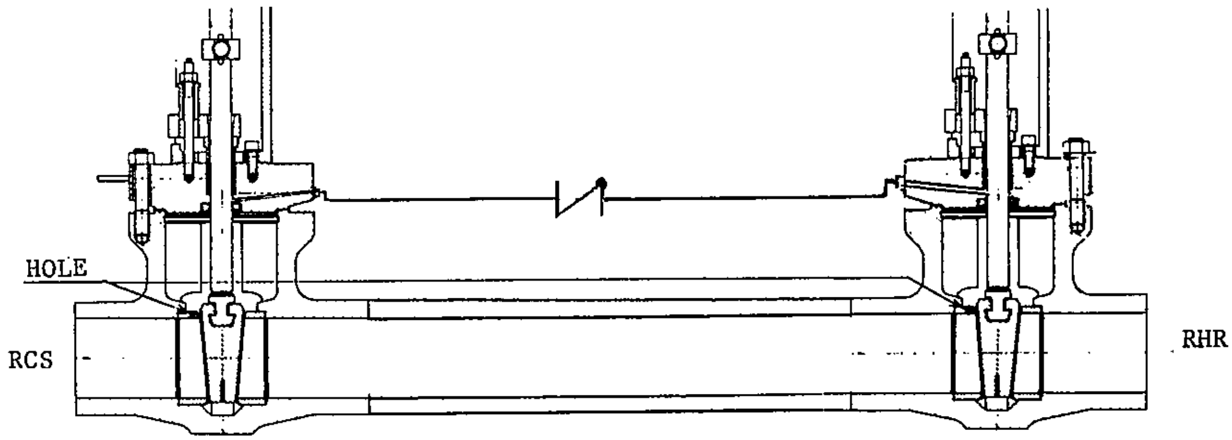

Figure 4. 900 MW RHR protection against pressure locking.

Conclusion

This case shows that liquid entrapment effect must be considered not only for the valve bonnet cavity but also for the piping between two isolation valves in series. A precise knowledge of operating procedures, piping layout, and operating conditions is required to preclude this effect because minor changes in one of these parameters may have unforeseeable consequences.

MAIN STEAM ISOLATION VALVES

Condensate Steam Entrapment Effect

In 1987, in Nogent 1, Cattenom 2, and Belleville 2, it was impossible to reopen some of the four valves after the warmup at 248°F (120°C)/hour of the downstream piping of the MSIVs. The MSIVs are double disc wedge gate valves with a pneumatic hydraulic actuator (see Figure 5). The open valves under no pressure differential because a bypass line allows the balancing of upstream and downstream pressures. In Cattenom 2, one valve could be reopened only 2 hours after the warmup. So, in 1988, tests were done in Nogent 2 with a pressure sensor installed on one valve to record the bonnet cavity pressure.

Following a cooldown and then a warmup of the downstream piping in 4 hours, the four valves were blocked closed. The pressure in the bonnet cavity reached 6,236 psi (43 MPa) and after 12 hours was still 3,625 psi (25 MPa). The upstream drains were closed, which increased the temperature differential because lukewarm condensate water was present upstream of the valve. With the drains open, the maximum pressure was 3,190 psi (22 MPa), 1,885 psi (13 MPa) above the normal no-load pressure. Some slight deformations of the bonnet were found during the subsequent valve inspection, which allowed reassembly of the bonnet without the need for machining. The events of the scenarios ran as follows:

- As the downstream pressure decreased during cooldown, the upstream disc lost its tightness, and condensate water and steam flowed in the bonnet cavity. Soon, the bonnet cavity was solid with condensate water, as steam condenses during contact of the cooler body and bonnet surfaces from the thermal losses. During the downstream piping warmup via the bypass line, the fluid under the bonnet, which is heated by conduction through the downstream disc, expanded and increased in pressure and applied the two discs against their seats. The high friction of both discs on the seats could overcome the operator thrust, which is limited by the maximum oil pressure under the cylinder piston, delivered by an air-actuated oil pump.

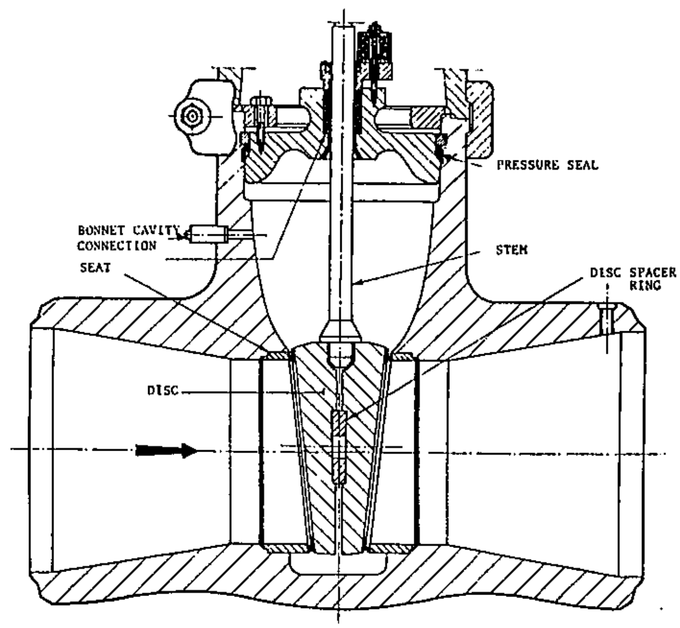

Figure 5. Main steam isolation valve.

To preclude the occurrence of such other events, a 1/2-in. external line has been installed connecting the bonnet cavity to upstream drain piping. This line was also fitted with a flange, allowing its closure during downstream line hydrostatic testing.

Conclusion

These events confirm that gate valves operating in steam are more susceptible than others to pressure locking as a result of the entrapment effect. Because they operate at high temperatures, they can be submitted to high-temperature gradients or high-temperature differentials that can rapidly heat up condensate steam under the bonnet.

Although in these cases the safety of the plant was not jeopardized because the MSIV was locked in the safety-related function to close, the stresses from the high pressures of the liquid entrapment effect may lead to permanent deformation of the valve discs or bonnet and preclude later correct operation.

CONTAINMENT SUMPS ISOLATION VALVES

Background

Observed during the decennial visit to Bugey 5 plant, a containment spray suction sump MOV failed to open after a tightness test, which was caused by actuation of the torque limit switch (see Figure 6). After operators bypassed the torque limit switch, the valve could open under the design pressure differential. However, subsequent analysis of the possible LOCA scenarios and testing of this double disc parallel seat gate valve showed a risk of failure to open.

As a matter of fact, those valves are normally closed and are requested to open after a LOCA when the refueling storage tank is empty to allow suction in the sumps for the containment spray pumps. Therefore, the valves still closed can be submitted to an upstream pressure of about 81 psi (0.56 MPa), corresponding to the sum of the containment design pressure 73 psi (0.5 MPa) and the weight of water between the sumps and the valve.

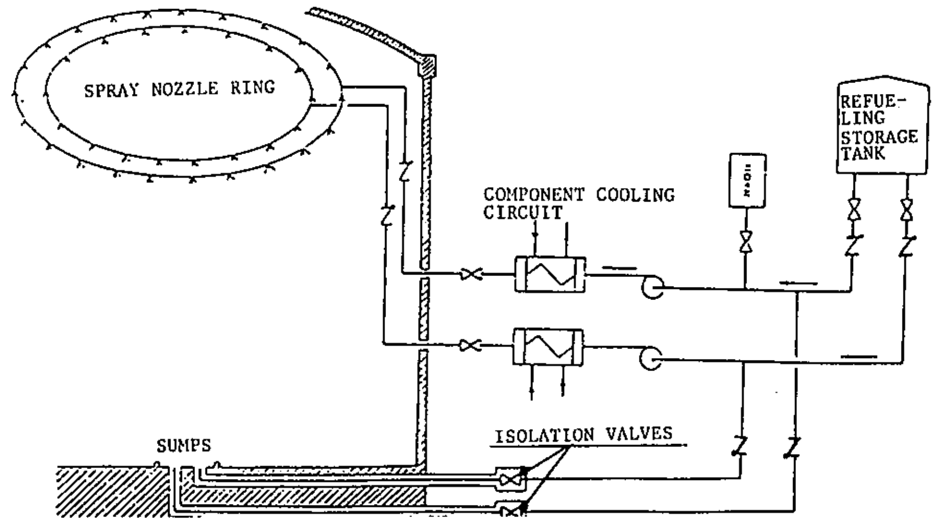

Figure 6. Bugey 5 containment spray system.

When the valve must open, the containment pressure has been reduced by the spray flow to 36 psi (0.25 MPa) and the pressure differential is about 22 psi (0.15 MPa), which should be easily overcome by the operator for a pressure differential of 73 psi (0.5 MPa) acting on one disc and its seat.

However, as testing at Les Renardieres EDF Research Center confirmed, on this type of valve there is a possibility of differential pressure locking and maintenance of high pressure under the bonnet many hours after the cancellation of the pressure differential. With such a behavior, the operator would no longer have been able to open the valve because of the added friction of the upstream disc that was not assumed in the operator torque calculation. Indeed, the total friction of both discs on their seats was then equivalent to the friction of only one disc under a pressure differential of 94 psi (0.65 MPa). Furthermore, EDF tests also showed that the bonnet cavity pressure followed the ambient temperature 16 psi/°F ($\sim$0.2 MPa/°C) and that there was a potential of pressure locking by liquid entrapment effect. However, in that case the valve inlet piping is always kept full of cold water by upholding a constant water level in the sumps, which acts as a water seal. Because the valve is located outside containment, the risk is negligible.

Consequences

On new 1400-MW plants not yet in operation (CHOOZ B1-B2 and CIVAUX 1 and 2), EDF decided to provide all safety-related active MOVs with bonnet cavity pressure limitation systems. For valves required to be tight in one direction only, an external bypass line fitted with a manual globe isolation valve will be welded on the bonnet and on the upstream nozzle.

For valves required to be tight in both directions, a circuit selector between two manual globe isolation valves will balance the bonnet cavity pressure with the higher of the upstream or downstream pressures. One type of circuit selector, manufactured by Vanatome, was successfully qualified at les Renardieres (see Figure 7). Another one, manufactured by Alsthom-Velan, is in the process of qualification.

For 900-MW plants already in operation, a more selective choice will be made. The choice will be based on functional analysis studies (position of valves before and after accident, risk relative to containment tightness, etc.) on tests of opening of valves submitted to liquid entrapment effect by expected environmental temperature increase (from a LOCA for valves located inside

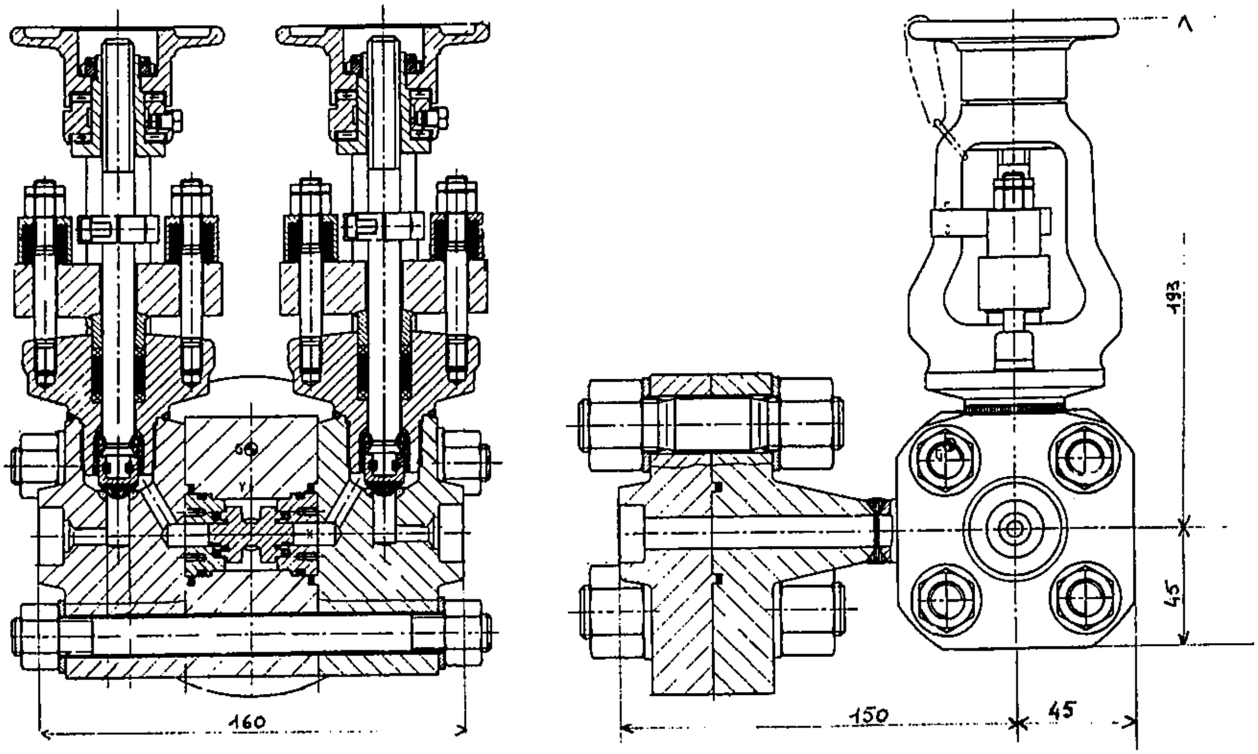

Figure 7. Circuit selector.

the containment, or from change in the ventilation duty during an accident for valves located in the auxiliary systems building), and on stress analysis for closed valves required only to keep their pressure boundary integrity.

PISTON EFFECT

Survey Findings

Statistical studies of valve leakage in 900- and 1300-MW EDF plants showed rates above the average for expanding parallel double disc gate MOVs. A premature tripping of the torque limit switch prevented a proper alignment of the discs to the seats. Indeed, as the seats began to seal the port area, the sealing was tight enough to allow pressure buildup in the bonnet cavity from the stem acting like a piston by further stroke travel.

This effect was first observed in 1983 during the qualification testing by EDF of a 3-in. 150-lb valve. The bonnet cavity pressure increase was measured and found to be equal to 189 psi (1.3 MPa). Testing in 1992 of a 16-in. valve of the same technology showed no pressure buildup and even, during some strokes, a decrease. It appears that for large valves of low pressure rating, the deformation of the discs from the stem wedging effect (see Figure 8) compensates for the stem piston effect.

This effect also occurs on wedge gate valves. However, its magnitude is limited by the very short travel of the stem after the wedging of the discs between the seats. Furthermore, when it occurs, the discs and the seats are already well-placed, and the consequences on the tightness of the valve are marginal.

Consequences

With the modification as described in the previous paragraph, changing all affected valves would have taken too long and been too costly. Because the guaranteed output of the installed operator torque allowed it for most cases, EDF asked Framatome to redefine new torque switch

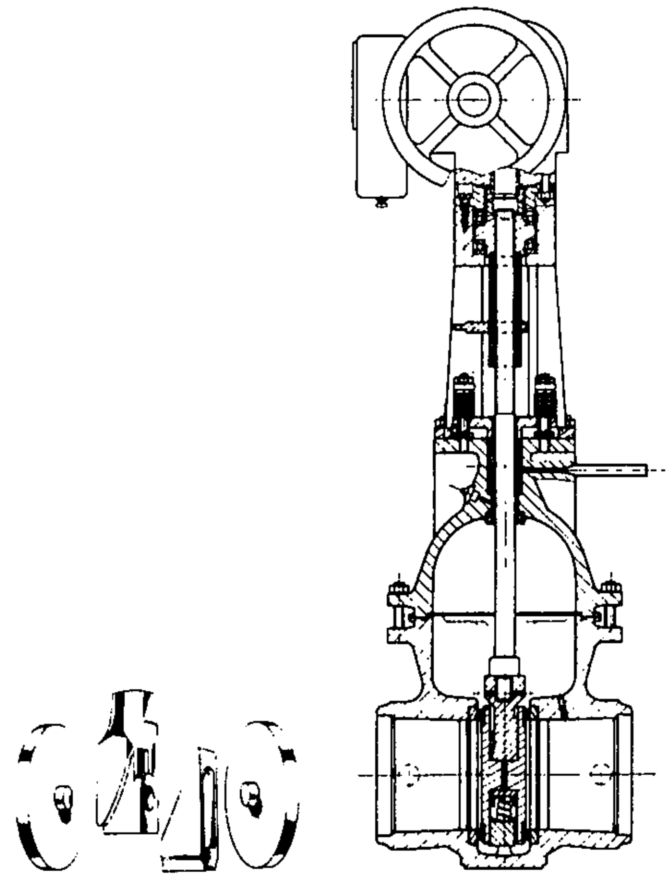

Figure 8. Parallel seats double discs expanding gate valve.

trip settings, taking into account the piston effect. So, added to the design differential pressure used for the stem thrust calculation was a term equal to two times the pressure buildup from the piston effect. This pressure buildup was supposed to follow a linear law, with 189 psi (1.3 MPa) for 3-in. valves and zero for 16-in. and above valves. This study also presented an opportunity to define a unique method of thrust calculation, based on indigenous and foreign experience that will be imposed on all suppliers of MOVs for EDF and Framatome.

GENERAL CONCLUSION

From the previous examples, it appears that many mechanisms involving trapped fluid under the bonnet of gate valves can induce malfunctions. However, the probability of malfunctioning is difficult to estimate because it depends not only on the packing and seating surface tightness of the fluid and ambient temperatures at the time of the event but also when the valve last operated and the plant operating procedures.

The number of reports of such cases is relatively rare. Most are undetected because valve actuator thrust margins are, in general, sufficient to overcome "mild" pressure locking events occurring during normal plant operation. However, special attention must be paid to accidental situations where operating conditions are the worst.

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Use of Motor-Operated Valve Diagnostic Systems in Japan

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ABSTRACT

The objectives of this paper are to (a) present an outline of the diagnostic devices and systems for motor-operated valves (MOVs) that were developed in Japan, (b) present diagnostic experience at Tokyo Electric Power Company's plants, (c) present the typical practices employed in the maintenance activities for MOVs in Japanese nuclear power stations, and (d) evaluate the prospect for future use of these diagnostic systems.

INTRODUCTION

In Japan, maintenance of motor-operated valve (MOV) actuators is usually accomplished during periodic overhaul. Recently, MOV diagnostic systems have been developed by Japanese manufacturers to test the valve actuator without overhaul. The use of the valve diagnostic system in Japan is neither commonly specified nor given by the regulatory position. However, because the equipment is available, we have been evaluating the new products at Tokyo Electric Power Company (TEPCO) facilities to find more effective ways of future maintenance, especially with respect to quality control and cost. We consider our evaluation results so far to be preliminary and expect them to be revised along the way. Recent computer technologies have progressed so rapidly that the available diagnostic systems are improving and our evaluation results are changing as a result.

OUTLINE OF DIAGNOSTIC DEVICES AND SYSTEMS AVAILABLE IN JAPAN

TOA Valve Company—TACS

The TOA Actuator Characterizing System (TACS) was developed by TOA Valve Company to obtain data relating to MOV actuators and to diagnose abnormal conditions.

The system takes in and records data during the plant outage from sensors installed on the actuators. Actuator torque is obtained by using the torque switch rotation angle, the stroke value is taken at the top of the stem, and status of the limit and torque switches in the terminal box is monitored. Data are analyzed by using a personal computer, and "good" or "no good" presentation is obtained from the display. The status of the torque switch bypass is also displayed on the screen.

TACS devices are available commercially. However, service is also provided in diagnosing the MOVs. System components and displays of TACS are shown in Figure 1. The diagnostic procedure is generally performed in five phases: (a) the valve system is isolated, (b) the valve control sensing wires are lifted, (c) sensors are attached and connected, (d) operations and data acquisition are performed, and (e) the valve system is returned to normal.

Major changes were made in developing the TACS, such as replacement of desk computers by portable devices and incorporation of improvements discovered in the field.

The basic problems commonly imposed on valve diagnostic systems are how to simplify the installation work and how to enhance durability in the site environment. Those ongoing needs, as well as the progress of computer technologies, have served to continuously improve and develop the machines.

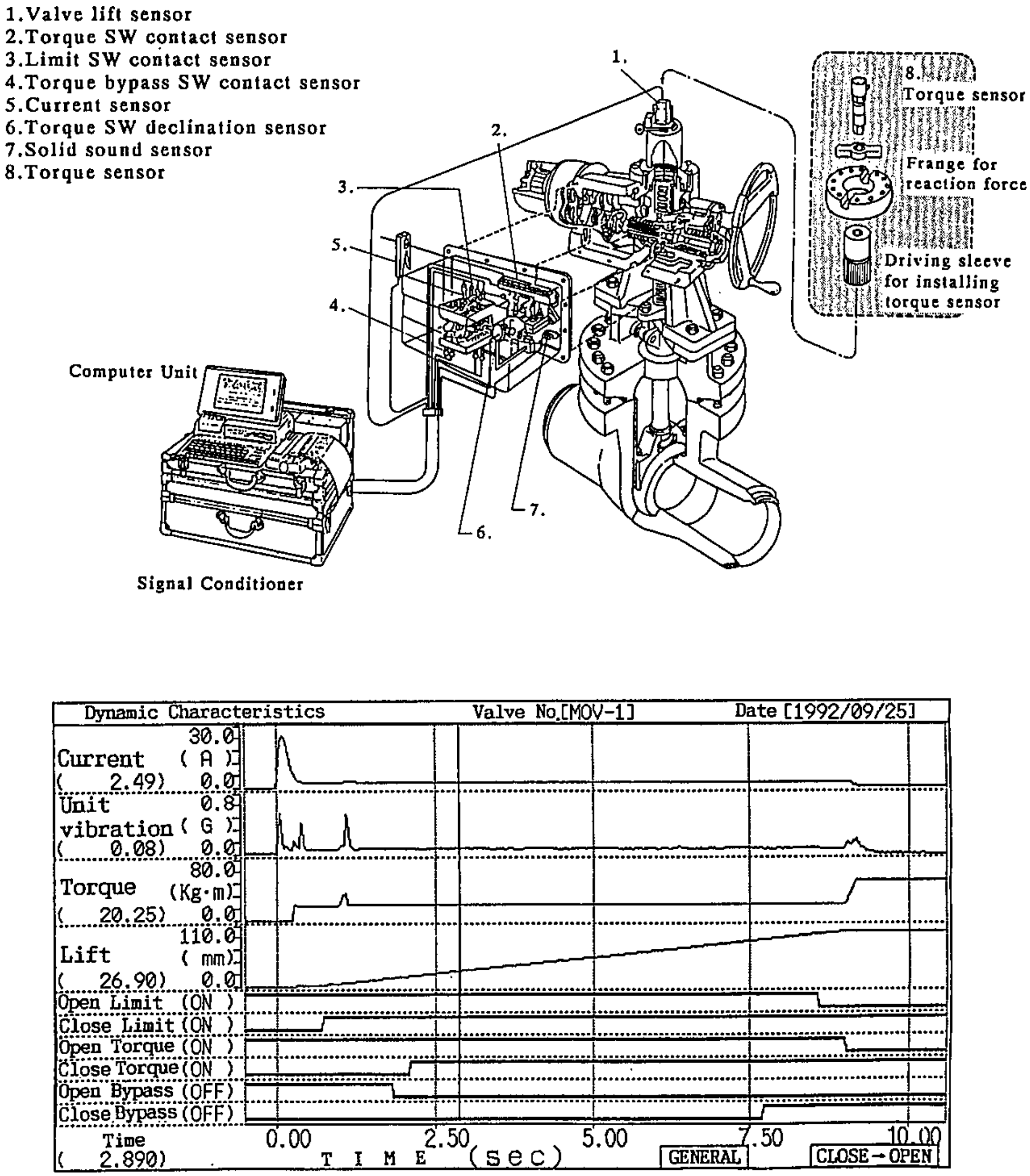


Figure 1. System components and the displays of TACS.

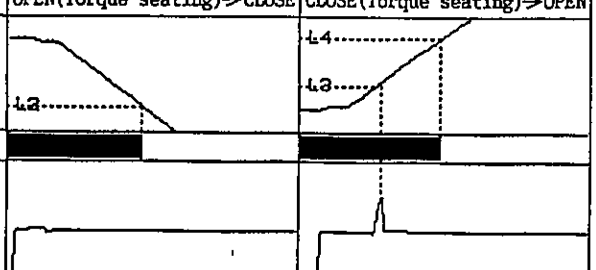
RESULTS OF DIAGNOSIS   VALVE No. [MOV-1]   Date [1992/05/25]

Diagnosis	No	Diagnostic Items
No good	01	Setting of valve lift
Good	02	Valve required operating time
No good	03	Setting of limit SW at opening side
Good	04	Setting of limit SW at closing side
Good	05	Setting of torque bypass SW
Good	06	Setting of torque SW
Good	07	Excessive torque of opening/closing
Good	08	Sliding resistance of gland packing
No good	09	Wearing of driving sleeve
Good	10	Loosening of lock nut
Good	11	Roughening of seating face
Good	12	Seizuring of stem
Good	13	Disc is fallen deep due to excessive inertia
No good	14	Wearing of disc
Good	15	Deterioration of wire dielectric resistance

Diagnosis	No	Diagnostic Items
Good	16	Deterioration of motor performance
Good	17	Operation delay of solenoid relay
Good	18	Wearing of actuator gears
Good	19	Seizuring of actuator gears
Good	20	Torque looseness of disc shut
Good	21	Vibration of unit
	22	
	23	
	24	
	25	
	26	Unconformity note
	27	Trend management
	28	Site diagnostic record of electric motor operated valve
	29	All diagnostic items copies (f.9)
	30	Previous menu (f.10)

[05] : Detailed Diagnosis : Setting of torque bypass SW (both side)

Power Plant : ○○ Electric Power Co.,LTD. ××Plant
Valve No. : MOV-1
Diagnosed Date : 1992/09/25
Performed maker : TOA VALVE CO.,LTD.
Operator : TARO TOA



	OPEN(Torque seating)→CLOSE	CLOSE(Torque seating)→OPEN
Lift (mm)		
Torque bypass		
Torque (Kg.m)		
Measure point(mm)	: L2= 85.5	L3= 5.4 : L4= 14.7
Setting scope (mm)	Open L.S.turn on 96.3≧L2 Good 85 ~ 90% to whole lift 83.9 ~ 88.8 83.9≦L2≦88.8 Good	Close L.S.turn on 2.0≦L4 Good 10 ~ 15% to whole lift 9.9 ~ 14.8 9.9≦L4≦14.8 Good
Judgment (mm)	——	L4-L3 > 1.0 Good

Setting of torque bypass SW are correct position.

f.2 function key to know in detail, because proper valve is torque seating at closing side and gate type as well.

Figure 1. (continued).

Nippon Gear Company—MAC

Motor Actuator Characterizing (MAC) was an MOV diagnosis system originally developed by the Limitorque Company in the U.S. However, in 1990 the MAC was improved using Nippon Gear's techniques and experience with both software and equipment. The latest MAC is completely different from the original. Data are acquired during the plant outage with sensors installed on the MOV actuators. Actuator torque is measured by the load cell at the worm gear, stroke is measured at the top of the valve stem, and limit and torque switch status are monitored. All data are sent to a personal computer and automatically analyzed. "Good" or "no good" status is displayed instantly. Nippon Gear Company engineers at the site evaluate the detailed results, and corrective action is taken within a day or so. MAC is used basically as a service provided by the Nippon Gear Company for diagnosing MOVs. System components and the diagnosis data of MAC are shown in Figure 2. The diagnostic procedure is essentially the same as was indicated above for the TACS system (Figure 1).

The requirements imposed on the valve diagnosis system are as indicated above. In order to simplify the installation of the valve diagnosis system, the company is developing a valve actuator with sensors installed at the factory. With such an actuator, MAC data can be taken without installing additional sensors, without lifting the wiring leads of the MOVs, and without disassembling and handling heavy parts of the valves. Therefore, MAC data can be obtained remotely during plant operation.

EXPERIENCE IN MOV MAINTENANCE AT TEPCO

Ordinary Maintenance Activities for MOVs

MOVs that are important for safety and operation are generally located in systems where maintenance during plant operation is difficult; consequently, they are overhauled about once every 10 years. Valve internal structures, including stem, disc, and seat, are visually inspected, contact conditions at the seat are checked, and consumable parts, such as packings and gaskets, are replaced. After the overhaul and reassembly, operational testing is performed, where limit switches are adjusted and the stroke time is measured.

Actuators and motors are overhauled once every 6 to 8 years, at which time visual inspections and applicable tests of each part are made. After the overhaul, the same kind of operational testing is performed as described above. An outline of MOV maintenance activities for a typical plant is shown in Table 1. A typical plant has approximately 345 MOVs.

The use of any automatic diagnosis for MOV status has not been introduced as a routine maintenance item, and no imminent need for this system is recognized.

Recent Experiences of Diagnostic System Application

The specific purpose of the valve diagnostic system in trial use comprises investigation of the root cause of incidents and confirmation of valve performance.

Measurement of Actuator Torque in the Investigation of an Incident. Fukushima-Daiichi Unit No. 2 experienced an incident in November of 1992 in which the steam inlet MOV of the high-pressure coolant injection (HPCI) turbine failed to open during testing of HPCI turbine manual start during the plant startup. As a result of the visual examination of the valve and motor, the motor had burned and lost its function. During the investigation, the required torque for valve opening was obtained both from measurement at the site and a simple analysis. The required torque was then compared with the motor specification. Measurement of torque at the site was taken at cold condition as basic data, and the simple analysis was used to estimate the hot condition value for that incident. It was concluded that the motor torque was smaller than the required torque.

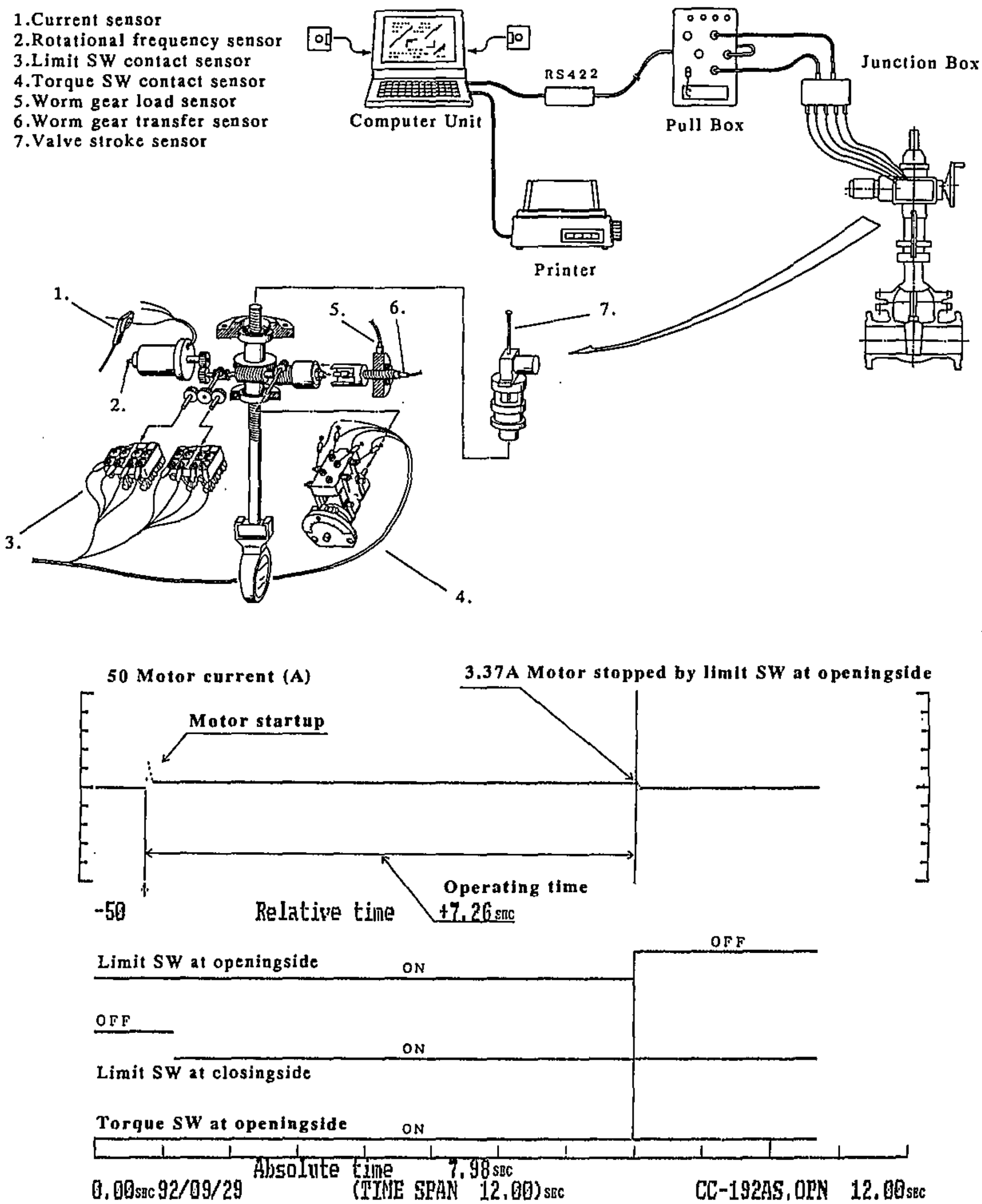
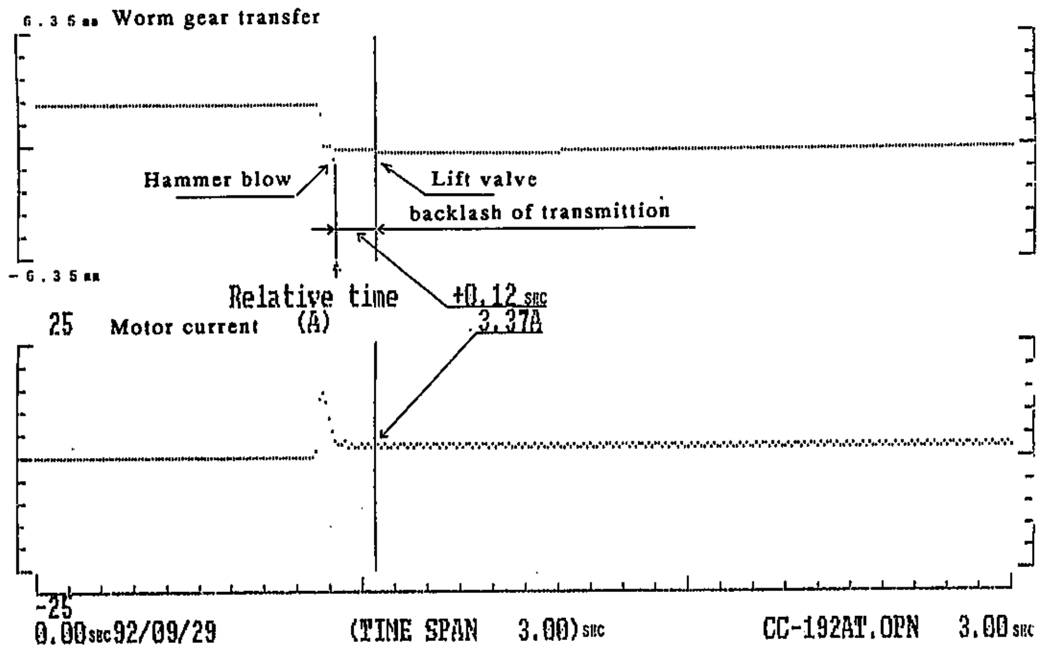


Figure 2. System components and the diagnosis data of MAC.



Results sheet sample of first diagnosis

No.	Diagnosis Items	Results	No.	Diagnosis Items	Results
1	Motor load(starting, running)		16	Torque seat current	
2	Mortor load, Running torque		17	Setting torque	
3	Running torque		18	Lowering torque after torque seat	
4	Running torque, Running thrust		19	Valve lifting torque	
5	Running thrust		20	Valve lifting thrust	
6	Trend of transmittance		21	Abnormal vibration	
7	Stem and stem nut		22	Deterioration of grease	
8	Wearing of stem nut		23	Loosening of spring pack	
9	Operation delay of reversing		24	Loosening of locking nut	
10	Operating time		25	Deterioration of limit SW	
11	Valve stroke		26	Deterioration of torque SW	
12	Setting of limit SW		27	Damage of wiring	
13	Setting of torque bypass SW		28	Insulation resisitance of power line	
14	Setting of torque SW		29	Insulation resisitance of control line	
15	Setting scale of torque Sw				

Figure 2. (continued).

Table 1. Outline of MOV maintenance (typical plant).

Items	Description
Maintenance Items	
Valve	Visual test (stem, disc, seat surface, internal surface) Penetration test (stem, body, disc) Contact at seat surface Replace gland packings and gaskets Measurement of stroke Measurement of operating time
Actuator	Visual test (assembly condition) Overhaul (change the grease) Setting point check of torque switch and limit switch Stroke meter test Declutch lever test
Motor	Visual test Measurement of insulation and coil resistance Commutator and brush test (only dc motor)
Period of Maintenance	
Valve actuator	Once every 10 years
Overhauls	Once every 6–8 years
Others	Once every 2–4 years
Motor	Once every 2–4 years

The following sections describe the application of the valve diagnostic systems in the investigation and the experience gained. The systems were used to identify any abnormal conditions in the valve in any parameters and to determine the required torque for opening at cold condition.

Diagnosis Using TACS. TACS was installed on the valve in question. The valve was opened and closed repeatedly, both by using the spare motor and manually. During the test, the stroke, valve actuator torque, and status of each switch were taken for each test case where the limit switch setting and torque switch setting values were varied, because the required torque for the valve opening depended on the limit and torque switch setting values. No anomaly responsible for the incident was identified from observing the data. The actuator torque value was taken from the angle of the torque switch, but a more precise measurement was desired.

Diagnosis Using MAC. MAC was installed on the valve in question. Sets of data were taken in almost the same kinds of tests as those using TACS (described above).

Using MAC, the worm gear torque was measured by a load cell attached to the end of the gear. It was considered that the data were more reliable because the load cell measured the torque precisely. In addition to directly measuring the stem axial force, strain gauges were installed. The results indicate there were no deficiencies of MOVs as with those of TACS. Because the required torque from the motor is directly influenced by stem thrust, the strain gauge data were judged to be appropriate for the investigation thereafter.

EXPERIENCE IN CONFIRMATION OF VALVE PERFORMANCE

Use of TACS for Evaluating Valves Before Plant Startup

Following the incident in Fukushima-Daiichi Unit No. 2 described previously and before the startup, valves in the emergency core cooling system important to safety and plant operation were randomly selected for TACS diagnosis. Twelve valves were diagnosed and the necessary actions, mainly limit switch adjustments, were made. At that time, the MOVs in the plant were categorized as A, B, or C, depending on their importance for operation and safety. Various testing items and data gathering were specified for each category. The tests were made either by conventional method or by TACS. Definition of valve category, corresponding testing items, and list of valves which were TACS tested are shown in Tables 2, 3, and 4, respectively.

Table 2. Definition of category.

Valve		Category
DC motor-operating valve		A
ECCS valve		
Open/close required for safety		A
Open/close required during plant startup		A
Open/close required during plant normal operation		B
Open/close not required during plant operation		C
Inside PCV valve		
Open/close required for plant safety		B
Open/close required during plant startup		B
Open/close required during plant normal operation		B
Open/close not required during plant operation		C
Others in reactor system		
Open/close required during plant startup		A
Open/close required during plant normal operation		B
Open/close not required during plant operation		—
Others in turbine system		
Open/close required during plant startup, located in main steam/feed water lines		B
Open/close required during plant startup		B
Open/close required during plant normal operation		C
Open/closed required during plant operation but is not essential for continued plant operation		—
Total number of Category A valves	44	
Total number of Category B valves	52	
Total number of Category C valves	239	

Table 3. Testing items.

Items	Category A	Category B	Category C
Visual test (valve, motor)	Yes	Yes	Yes
Operating test			
Before operation, check on the following conditions:			
Position (open, close)	Yes	No	No
Stroke indicator	Yes	No	No
Setting of torque switch	Yes	Yes	No
Megger	Yes	Yes	No
Coil resistance	Yes	No	No
Contact surface of limit switch	Yes	No	No
Terminal	Yes	No	No
Wiring	Yes	No	No
Grease	Yes	No	No
Grand bolt torque	Yes	No	No
Voltage of power source	Yes	No	No
During operation, to measure or confirm the following:			
Stroke	Yes	No	No
Motor current	Yes	Yes	No
Operating time	Yes	Yes	No
Operating condition	Yes	Yes	No
Stem surface (wear)	Yes	No	No
Switching (limit switch, torque switch)	Yes	Yes	No
Lamps (on/off)	Yes	Yes	No

Other Valve Performance Evaluations

TEPCO has had considerable experience with MOVATS, which is an early diagnostic system based on spring pack technology. Diagnostic trials using TACS, MAC, and MOVATS allowed an evaluation of the technologies. The results are shown in Table 5.

GENERAL ASPECTS OF MOV DIAGNOSTIC SYSTEMS IN JAPAN

Recently in Japanese nuclear power stations, valve diagnostic systems are increasingly being used or purchased for valve maintenance activities. Some of these are aimed at replacing the conventional valve or actuator maintenance

Table 4. List of valves that were TACS tested.

Valve number	Valve name
13-41	RCIC pump inlet isolation valve (from suppression chamber)
13-20	RCIC pump first outlet valve
13-21	RCIC pump second outlet valve
13-27	RCIC pump minimum flow valve
13-18	RCIC pump inlet valve (from CST)
13-39	RCIC pump inlet valve (from suppression chamber)
13-16	RCIC turbine inlet valve (outside PCV)
10-17	RHR pump inlet valve (outside PCV)
12-18	CUW line isolation valve (outside PCV)
23-17	HPCI pump inlet valve (from CST)
23-57	HPCI pump second inlet valve (from suppression chamber)
02-77	Isolation valve of main steam drain line

Table 5. Experience diagnosing MOVs at TEPCO.

Year	Plant	Diagnosis system	Total number of valves
1988	Fukushima-Daiichi Unit No. 3	MOVATS	34
1989	Kashiwazaki-Kariwa Unit No. 2	MAC	10
	Fukushima-Daiichi Unit No. 3	MOVATS	47
	Fukushima-Daiichi Unit No. 5	MOVATS	77
1990	Kashiwazaki-Kariwa Unit No. 1	MAC	40
	Fukushima-Daiichi Unit No. 3	MOVATS	103
	Fukushima-Daiichi Unit No. 5	MOVATS	76
1991	Kashiwazaki-Kariwa Unit No. 1	MAC	2
	Fukushima-Daiichi Unit No. 3	TACS	20
1992	Fukushima-Daini Unit No. 3	MAC	3
	Fukushima-Daiichi Unit No. 2	MAC	2
	Fukushima-Daiichi Unit No. 2	TACS	13
1993	Fukushima-Daiichi Unit No. 3	MAC	3

activities with diagnosis systems. However, we understand that no common evaluation results have yet been obtained.

EVALUATION FOR MOV DIAGNOSTIC SYSTEMS

Based upon the diagnostic experience described in this paper, the following items summarize our current evaluation of MOV diagnosis systems.

Diagnostic System Function Considerations

The MOV diagnostic systems currently available in Japan are mainly for the actuator and not for the valve internals.

The experience gained from investigating Fukushima-Daiichi Unit No. 2 incident suggests that it is necessary to measure the stem load directly to obtain the valve actuating load.

It is not desirable to increase the measuring parameters, but to limit them to the essential ones.

Automatic diagnostic functions should be limited because professional engineers are required at the site if the diagnosis results indicate "No Good."

Conventional valve maintenance activities are sufficient to keep the MOVs in good condition.

Economic Aspects

The cost of valve diagnosis is higher than conventional valve maintenance, and conventional maintenance activities will be retained for those valves that can be overhauled or adjusted.

Because currently available valve diagnostic systems are improving dramatically, it is desirable to request some diagnostic services to monitor current technology. It is realistic to request the service of the company who develops the diagnostic system when the diagnosis is made.

It is possible to diagnose three valves per day with the current diagnostic system at the site, considering the time for system isolation, installation, and removal of sensors. One way to decrease cost is to simplify the installation or preparation work.

Effective Use of MOV Diagnostic Systems

Use of currently available diagnostic systems is considered to be effective for the following activities in the maintenance of MOVs:

- Monitoring MOV conditions when located where system isolation is difficult
- Investigating an incident when more quantitative and detailed data on the MOV condition are required
- Making a quantitative evaluation of the operating condition based on data from the outage
- Keeping a record of the MOV adjustment or setting of switches.

CONCLUSION

Future developments desired for currently available MOV diagnostic systems are (a) cost reduction per valve, (b) toughness or durability for diagnostic systems equipment in field use, and (c) simple machine design that meets the fundamental minimum functions.

Conventional MOV maintenance activities should be continued, while watching the status of the development of diagnostic systems.

When the cost for using a diagnostic system is less than conventional maintenance activities, it will become meaningful to replace the current maintenance activities with an appropriate diagnostic system.

Session 3B
Risk-Based Inservice Testing

Session Chair
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Applying Reliability Centered Maintenance Analysis Principles to Inservice Testing

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ABSTRACT

Federal regulations require nuclear power plants to use inservice test (IST) programs to ensure the operability of safety-related equipment. IST programs are based on American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requirements. Many of these plants also use Reliability Centered Maintenance (RCM) to optimize system maintenance. ASME Code requirements are hard to change. The process for requesting authority to use an alternate strategy is long and expensive. The difficulties of obtaining this authority make the use of RCM methods on safety-related systems not cost effective. An ASME research task force on Risk Based Inservice Testing is investigating changing the Code. The change will allow plants to apply RCM methods to the problem of maintenance strategy selection for safety-related systems. The research task force is working closely with the Codes and Standards sections to develop a process related to the RCM process. Some day plants will be able to use this process to develop more efficient and safer maintenance strategies.

MAINTENANCE STRATEGIES TODAY

Industrialists know that maintenance is a key to efficient, reliable operation of their facilities. Today, industries employ a multitude of maintenance strategies to ensure proper plant operation. Nuclear power plant operators employ the full range of strategies.

Approximately 25 years ago maintenance engineers in the aircraft industry developed a new maintenance strategy process. The new process analyzed system functions and developed a maintenance program to preserve those functions. The new strategy ensured the functions' availability. The program provides the most reasonable, cost-effective preventive maintenance program. This strategy is Reliability Centered Maintenance (RCM) (Nowlan and Heap, 1978).

The American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Standard has been in use for a century. Based on proven principles, these standards proscribe inspections and tests to ensure the integrity and operability of key equipment. The nuclear industry relies on portions of the ASME Code, and the newer Operations and Maintenance Code, for this purpose. These programs are called inservice inspection (ISI) and inservice testing (IST). Unfortunately, the Code inspection and testing processes are often not up to date. The code often bases the selection and scheduling of tests and inspections on the worst-case analysis for *all* components of a particular type, whatever the plant application. A strategy based on RCM eliminates this inefficiency.

Nuclear plant operators who hope to employ RCM to improve the efficiency of their ISI and IST programs have a major problem. The U.S. Nuclear Regulatory Commission (USNRC) procedures allow an operator to propose new ISI and IST methods, other than those proscribed, to meet Code requirements. The operator, however, would have to prove to the USNRC that the new technology protects public safety as effectively as the old. This is theoretically possible, but, by

necessity, the USNRC typically demands a rigorous proof. The widespread feeling among operators is that the analysis would be too difficult and a waste of time and resources. If their improvements conflicted with the Codes, the USNRC would not accept them and the plants could not implement the changes. If one operator justified the effectiveness of RCM, others would have an easier time, but nobody wants to be the first to try.

NEW PRESSURES, NEW TECHNOLOGIES

A new competitiveness is now sweeping the electric utility industry. Utilities must be cost efficient and profitable to survive. Nuclear plant operators need a maintenance strategy that reduces costs, maintains safety, and uses the latest technology. And the strategy must provide effective tests and inspections, with realistic schedules, that recognize the relative importance of the components tested.

The ASME Council on Research (not part of Codes and Standards) is sponsoring a research task force on risk-based testing. This task force is developing a maintenance definition process that combines methods similar to RCM with some new analytical tools. The task force includes representatives from many organizations. Coordination with these agencies promises acceptance of the process when the task force publishes its report.

Plant maintenance would benefit tremendously if nuclear plants could benefit from the application of RCM process efficiency to safety-related systems.

Risk-based inservice testing has some major technologies that could enhance the RCM process (Balkey et al., 1991). With these new technologies, analysts can rigorously demonstrate the value of one maintenance strategy over another. Risk-based inservice testing should become a tool for all utilities to determine the safest, most efficient, and most cost-effective maintenance strategy.

ASME CODES AND STANDARDS ORGANIZATIONS

The ASME Codes and Standards Council operates through several boards. The boards are each composed of committees. The construction and operation of nuclear plants is under the cognizance of the Board on Nuclear Codes and Standards (BNCS). BNCS oversees the Operations and Maintenance Committee and the Section XI and Section III Subcommittees.

The decisions of the boards and committees must be made by consensus—that is, the decisions must be substantially unanimous. Committees, subcommittees, and their working groups meet quarterly. Because of the infrequent meetings and the need for consensus, changes in the codes and standards arena come slowly.

This slow pace can be a benefit. Committees make changes carefully. The standards writing process ensures that all views and opinions are considered. Where safety is a primary concern, operators must not discard what has worked and been accepted without careful consideration of the consequences.

This benefit is also a liability. Codes and standards are stodgy. New technologies are introduced slowly. Improved methods—either safer or more cost effective—are not easy to introduce.

RELIABILITY CENTERED MAINTENANCE

As discussed above, RCM is a preventive maintenance optimization method. Preventive maintenance includes all maintenance except corrective maintenance, including scheduled maintenance, predictive maintenance, and monitoring. Run-to-failure, which includes corrective maintenance, is acceptable as a preventive maintenance strategy if the failure consequences are well understood. The RCM process has proven effective in many industries and with all types of systems and components. It is accepted and encouraged by several nuclear power industry

research and management groups and by the USNRC.

RCM experience has shown areas where some plant maintenance uses obsolete inspections and tests. RCM is especially effective at improving maintenance efficiency on systems that have a high failure rate and that are critical to availability, expensive to run, or expensive to repair.

Several variations to the RCM process exist. All, however, follow the same general pattern:

1. RCM analysts delineate the system boundaries. They divide systems along functional lines. That is, components grouped within each system boundary are related to a particular function (e.g., cool the core by providing cooling water).

2. Plant management decides upon which systems to carry out an RCM analysis. Usually plants select systems that get the higher return for their analysis dollar. The first input to this decision is likely to be a probabilistic safety analysis. Other common inputs are failure rate data and management's sense of a system's criticality.

3. Determine which functions are important to preserve.

4 RCM analysts perform a failure modes and effects analysis (FMEA) or a failure modes, effects, and criticality analysis (FMECA) or criticality checklist analysis (CCA). These analysis techniques determine the dominant critical component and failure mode combinations (e.g., x valves fail to close) that produce significant failure consequences. Determining combinations of dominant critical component and failure modes and their most likely failure causes sets RCM apart from most other maintenance programs. This thorough analysis tool finds and describes the dominant failure modes and associated components constituting the major challenges to the important system functions. As with system selection, analysts often use failure rate data and life expectancy data to assist their maintenance program selection. After the FMEA or FMECA system analysts will know which components are associated with critical failure modes. Once the system analysts know what equipment to protect, they can focus resources on failure prevention and mitigation.

5 After determining the failure modes, effects, and possibly, criticality, the analysts identify failure causes.

6 RCM analysts select the optimum maintenance strategy for each failure mode and cause. The purpose of the maintenance program is to prevent or mitigate these failures. Strategies can be any combination of scheduled maintenance, monitoring, fix-when-fail, or hidden-fault-finding. The analysts use their best engineering judgment to make their selection because there are no governing rules. As with system selection, analysts often use failure rate data and life expectancy data to assist their maintenance program selection. They usually use a combination of generic and plant-specific data. They also use failure rate data to select the proper maintenance frequency.

7 Analysts next perform a task comparison between the old maintenance strategy and the RCM-determined strategy. Plant management can then decide which strategy to follow.

8 After the analysts select the appropriate maintenance for each failure cause, appropriate site organizations prepare procedures, establish organizations, conduct training, prepare software, and purchase equipment.

A wise plant management will have used site maintenance personnel, probably in combination with contractors and corporate specialists, to develop the RCM program. When management uses existing personnel, the personnel will already understand the new procedures and

accept their merit, making implementation already complete.

RCM EXPERIENCE TO DATE

Many plants have implemented RCM programs. The nuclear power industry and other industries have many success stories for RCM. Plants have eliminated much extra maintenance, and plant equipment is more reliable. When done well, the programs have typically saved time and money. As a minimum, the RCM process produces a technical basis for the existing maintenance program. To date, implementation has been primarily on balance of plant systems. On these systems, the plant is usually free to change maintenance programs as they desire. Systems with regulatory-directed maintenance, such as ISI and IST, face a serious problem implementing RCM, however. The RCM analysis process will work as well on safety-related systems to optimize the preventive maintenance program. Plant personnel recognize, however, they are not free to implement their RCM findings. Even when RCM points to a different maintenance strategy, regulations (the Code) will constrain the maintenance selection. The plants can request a change in their program from the USNRC. The first plant to request a change, however, will face a monumental job. Even a receptive USNRC will demand thorough proof of the new concept.

Another problem RCM analysts face is the lack of a numerical basis of the analysis. Analysts need this information to gauge the probability and frequency of failures. They have available some plant failure data, industry failure data, and life expectancy data. They rarely have enough maintenance history on individual components. These data point to weak plant areas, but they are rarely specific enough to select between alternate maintenance strategies.

Occasionally, plants have had problems implementing RCM programs. Often this is the result of inadequate planning for implementation. At some plants an isolated plant group or a contractor does the RCM analysis without involving the actual maintenance organization and its personnel. When this happens, maintenance personnel will feel no pride of ownership, and will resist trying the unknown.

Some plants have not followed through on implementation. After completing RCM analysis on an initial group of systems, these plants have not followed through with a plant-wide program.

THE IDEAL MAINTENANCE STRATEGY

The ideal maintenance strategy would be based on the RCM process. RCM analysts would back up their program with good, quantified data. If these data were not available from plant and industry databases, the analysts could quantify data from other sources, such as expert elicitation, which will be explained later. The analysts would select the optimum strategy through a rigorous decision analysis process.

And, ideally, maintenance analysts could implement this strategy process on any system, whether covered by ISI/IST or not. The Operations and Maintenance or Section XI Code would allow plants to use the most effective maintenance strategy, as long they could demonstrate its efficacy and value.

RISK-BASED INSERVICE TEST TASK FORCE

A new organization has entered the scene, the Risk-Based Inservice Test Task Force (RB-IST TF). ASME, through their Council of Technology, has created this organization to meet industry's needs for a scientific approach to risk. The Task Force charter directs it to determine appropriate risk-based methods for developing guidelines to be used in the inspection of light water reactor (LWR) nuclear power plant components. Although the process can be applied to components within an entire LWR plant, the longer term objective is to make comprehensive recommendations to the Operations and Maintenance Code. Like the codes and standards committees, members of the research task forces represent every facet of the nuclear power

industry—plant operators, manufacturers, regulators, insurers, and research organizations.

The RB-IST TF defines risk as the product of the probability of an event occurring and the consequences of it occurring. For example, if you have one chance in fifty (0.02) of losing $100, the risk is $2. *Cost* can be defined several ways: dollars, human lives, radiation exposure, etc. Savings are analyzed as negative costs. The RB-IST TF is developing an analysis process to evaluate alternate maintenance strategies and select the strategy with the lowest risk.

The maintenance strategy selection process developed by the RB-IST TF determines not only the risk of the current strategy, but can also be used to determine the risk of alternate strategies not yet tried. This process is similar to RCM analysis. First, analysts partition the facility into systems. They then perform FMECAs on selected systems. The FMECA pinpoints the critical failure modes and causes. After selecting candidate maintenance strategies, the RB-IST TF process uses sophisticated analysis tools to find the total expected cost of each candidate strategy. *Cost*, again, can be denominated in dollars, exposure, or mortality. Analysts then select the strategy with the lowest cost.

IMPROVED ANALYSIS TOOLS

The risk-based process has some new and very effective analysis tools. I will discuss each briefly in the following paragraphs.

Used now by RCM analysts, probabilistic safety assessments (PSAs) [previously called probabilistic risk assessments (PRAs)], structural reliability and risk assessments (SRRAs), and reliability and availability assessments rank systems on importance. Analysts can measure this through contribution to core damage frequency or other risk-based measure. Plants use these importance rankings to decide which system to analyze. Analysts also can use these assessments in a quantified risk valuation. Another effective, but less well-known tool is expert elicitation. Expert elicitation quantifies the first-hand experience of knowledgeable personnel. These experts often are operators and maintenance personnel with field experience in power plants, both professional or craft. They know of undocumented failures, undocumented human errors, and they have a sense of failure causes and background that also often does not get documented. Expert elicitation is a highly specialized skill based on scientific research. Analysts should use only qualified practitioners for an expert elicitation operation.

Analysts can use analysis algorithms such as risk achievement worth, risk reduction worth, or Fussell-Vesely. These algorithms establish the contribution of a particular component's failure likelihood to overall risk. Although these techniques have recently become available to RCM analysts now, they are not widely used.

Decision tree analysis totals the risks (costs) of all possible outcomes of a decision or strategy. Once again, the risk is the product of the likelihood of an event happening and the consequence. The sum of the likelihoods of all outcomes must equal one (100%). For instance, assume a maintenance strategy calls for monitoring a parameter so that the plant can replace the component before failure. Outcomes, each with its probability of occurrence, might be one of the following: the part does not fail; the part fails and the monitoring detects the failure (timely replacement of the part); the part fails and is not detected by the monitoring (failure of the system); or the part does not fail, but the monitor indicates it does (unnecessary part replacement). Decision tree analysis finds the total cost of each outcome, including monitoring costs, consequential system damage costs, and repair costs. Each total cost is multiplied by its likelihood. The total cost of the monitoring strategy is the sum of the costs of the different outcomes. Not all costs can easily be quantified (i.e., bad publicity or increased USNRC scouting). It is worth the effort, however, for analysts to assign a cost or range of costs to each of these, because, in fact, *they are costs*, and plants should account for their costs.

Analysts can use standard definitions of failure probability estimates to derive credible data from subjective estimations. For instance, an event that

individually may be expected to occur infrequently but more than once during the lifetime of the component can have its failure probability set to 10E–1 per year. An event of such low probability that an event is rarely expected to occur can have its failure probability set to 10E–6 per year. A not credible event can have its failure probability set to 10E–6 per year. Obviously analysts must use such values with caution.

WHAT CAN WE EXPECT

The RB-IST TF's output is a report due approximately in September 1995. The report will explain the risk-based process and how plants can learn to apply it. In the meantime, the RB-IST TF is working with the ASME Operations and Maintenance Committee. This cooperation will determine if the Codes and Standards organization can adopt RB-IST TF principles. If Codes and Standards can use the principles, the two groups will work out how to best implement the changes.

Implementation will possibly involve both an interim and a final approach. In either case, the first step will be ranking the systems in order of the safety significance. This could include two, three, or more groups. The top group would be those systems clearly of safety significance. The bottom group would be those systems clearly of no safety significance. Middle groups, if any, would fall somewhere in between. This group might be systems that are safety significant in some modes of operation but not others.

For the interim period, codes and standards organizations might prescribe the maintenance for each ranking group, or, at least, the more safety-significant systems group. A final approach would have each plant, *by following the prescribed process*, select the optimum maintenance strategy for *all* systems.

PLAN OF ACTION

The organizations concerned are interested in implementing risk-based testing into the O&M Code and are investigating the feasibility of such a move. The RB-IST TF is still developing its process and is not ready to issue its final report. The codes and standards organization has only been introduced to the risk-based testing concept and is discussing possible implementation paths with the RB-IST TF. Therefore, these groups have only begun limited development of an implementation process. To facilitate implementation, the RB-IST TF schedules its quarterly meetings to coincide with the Operations and Maintenance Committee meetings. In addition, three members of the RB-IST TF are also codes and standards committee or subcommittee members.

The Special Committee on Standards Planning of the Operations and Maintenance Committee is preparing a plan of action to implement the RB-IST TF process with the O&M Code. While only in a preliminary form, the plan of action will probably include the following:

- One or more of the O&M working groups will develop a prototype risk-based code for some sample systems. Volunteer utilities will implement these on systems at pilot plants.
- Task force and special committee members will identify implementation requirements, identify required technology, and develop specifications for implementation tools (e.g., software). At the same time the plants will develop training plans.

THE PROMISE

The nuclear power industry needs a system that quantifies risk. When utilities have that, they can develop a system that minimizes risk.

When the codes and standards organization adds RB-IST principles to the Code, plants will have a valuable tool to develop a comprehensive, risk-based maintenance program. To the degree the plants have dependable failure data, they can accurately determine the true risk of the current maintenance strategy and each proposed maintenance strategy.

Analysts can evaluate the change in the failure rate of a component with time. Using the

probabilistic safety analysis, they can link the failure rate to risk. The test frequency can be set so as to maintain the overall risk at an acceptable level, and at the lowest cost.

RCM is the best system developed so far for finding and deciding on key plant equipment and its critical failure modes and causes. The risk evaluation and decision analysis tools developed by the RB-IST TF give an added dimension to RCM. This new dimension gives the RCM analysis results a more quantifiable basis, which then allows the substantiation for use with the Codes and Standards.

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Evaluation of the Safety Benefits and Costs of Proposed Revisions to Inservice Testing Requirements for Pumps and Valves

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ABSTRACT

This paper describes the results of an evaluation of the potential safety benefits and costs associated with a set of proposed revisions to American Society of Mechanical Engineers (ASME) Code requirements for inservice testing of pumps and valves. In September 1991, the U.S. Nuclear Regulatory Commission (USNRC) requested that the ASME Operations and Maintenance Committee consider the incorporation of revisions to the Code. The revisions would require that inservice pump and valve testing verify all safety functions and be performed at or near design-basis conditions. Probabilistic risk assessment models developed for the USNRC and the failure data used in performing these probabilistic risk assessments were evaluated to estimate the potential reduction in public risk. Pump and valve failures that might be prevented by the proposed testing were identified. Estimated potential reductions in core damage frequency and associated reductions in public risk were calculated. The results of this evaluation indicate that the proposed revisions to the ASME Code requirements for inservice testing would result in minimal safety benefits that would not meet the "significant additional protection" standard established in the backfit rule. Safety benefits estimated in this analysis are several orders of magnitude lower than those that would be required for the proposed revisions to be cost effective. An alternate approach that optimizes inservice testing requirements based on the contribution of each pump or valve to the risk of core damage would be a preferred means of enhancing safety.

INTRODUCTION

In a letter dated September 9, 1991, from James E. Richardson of the U.S. Nuclear Regulatory Commission (USNRC) to Forrest T. Rhodes of ASME (Richardson, 1991), the USNRC requested that the American Society of Mechanical Engineers (ASME) Operations and Maintenance (OM) Committee consider revising existing requirements for inservice testing. The letter requested revisions to ensure the ability of certain pumps and valves to perform their intended hydraulic and mechanical safety functions. The following revisions were requested:

- Expand the scope to include specific components that are not constructed in accordance with the ASME Code Section III rules for construction or tested in accordance with the ASME Code Section XI
- Require verification of each safety function of each included component
- Require that such verification be accomplished at design-basis conditions, or, where such verification is not possible, with a test

at less than design-basis conditions combined with an analysis

- Require that data collected during component testing be compared with data taken during previous tests to determine the condition of the component.

This request was made in part as a result of USNRC concerns with the ability of some components to perform their safety functions under design-basis conditions, such as motor-operated valves and check valves, and concern that the inservice tests required by ASME Section XI and incorporated by reference into 10 CFR 50.55a(f) do not (a) include each component that has a hydraulic or safety-related function (b) accomplish verification of each safety function of each safety-related component, or (c) require that such verification be accomplished at the design-basis conditions.

The USNRC asked ASME to consider initiating, as a high priority item of work, an OM Code development effort that would incorporate such revisions. To assist in its evaluation of this USNRC request, utilities participating on the ASME OM Special Committee on Standards Planning requested assistance from the Electric Power Research Institute (EPRI) Plant Support Engineering (PSE) in estimating the safety benefits and costs that would be associated with the proposed revisions.

In response to this request, EPRI PSE reviewed the existing probabilistic risk assessments and related data to provide an estimate of safety benefits. Where necessary because of lack of data or resource constraints on the evaluation, simplifying assumptions were made that would maximize the estimate of the potential safety benefit. Cost data were obtained through review of existing power plant inservice testing programs and interviews with personnel responsible for implementation of those programs.

This evaluation was managed by Mr. William Houston of EPRI PSE, Charlotte, North Carolina. The principal investigators were C. Wesley Rowley of Rowley Consultants, Cashiers, North Carolina, and Daniel L. Maret of Sequoia Consulting Group, Inc., Randolph, Massachusetts. The results of this evaluation are documented in EPRI Report TR 102240, *Evaluation of the Safety Benefits and Costs of Proposed Revisions to Inservice Testing Requirements for Pumps and Valves*, August 1993.

METHODOLOGY AND ASSUMPTIONS

Methodology

The evaluation of the potential safety benefits and costs associated with the USNRC proposed inservice testing revisions was performed in a manner similar to that used in the USNRC regulatory analysis for the Maintenance Rule (USNRC, 1991a). USNRC guidance on performance of value/impact analyses (Heaberlin et al., 1983) was also used as input.

The methodology used was to identify the potential effects of the proposed revisions on failures important to risk of core damage in two representative probabilistic risk assessments; to estimate the reduction in core damage frequency that might result, and to estimate the associated reduction in the risk of public radiation exposure that might result.

The major steps in the evaluation included the following:

1. Definition of the "Base Case"

The "base case" for the evaluation was defined as the set of tests performed under current inservice testing programs at operating nuclear power plants.

Data were obtained for eight operating nuclear plants to identify current inservice testing practices. In particular, the scope of the programs was reviewed to determine whether the existing tests (a) include all safety related pumps and valves in their scope, (b) verify all safety related functions of those pumps and valves, and (c) are performed at or near design-basis conditions.

2. Definition of the "Change Case"

The change case was defined as full implementation of a revised inservice testing program that includes all of the features requested in the Richardson letter (Richardson, 1991).

3. Estimation of Safety Benefits

Sources of information regarding pump and valve failure rates, failure causes, and associated public risks developed by or for the USNRC in previous analyses were used as input to the estimation of safety benefits. The probabilistic risk analyses performed under NUREG/CR-4550 for the Surry (Bertuccio and Julius, 1989) and Peach Bottom (Kolaczkowski et al., 1989) plants were used to estimate the impact of the proposed inservice testing revisions on public risk. NUREG/CR-1150 (USNRC, 1990), which summarizes the methodology and results of the NUREG/CR-4550 analyses, was also used. NUREG/CR-1205 (Trojovsky, 1982) was the primary source of data on pump and valve failure rates and causes for the NUREG/CR-4550 analyses.

An estimate of the reduction in pump and valve failures that could result from implementation of the proposed inservice testing revisions was made. Each source of pump or valve unavailability in the probabilistic risk assessments was reviewed. Failures for which the proposed revisions could reasonably be expected to result in improvements in availability were identified.

The primary source of information used for evaluation of the effects of component failures was NUREG/CR-4550, Volume 1 (Ericson et al., 1990), which describes the methodology, analyses, and results of probabilistic risk assessments for five operating U.S. nuclear power plants. NUREG/CR-1205 (Trojovsky, 1982), which contains an analysis of pump failure probabilities and causes, was the source of much of the failure rate data used in the NUREG/CR-4550 analyses.

The potential reduction in core damage frequencies and risk of public radiation exposure were calculated using data from NUREG/CR-4550 Volume 3 (Bertuccio and Julius, 1989) and Volume 4 (Kolaczkowski et al., 1989), with additional information taken from NUREG-1150 (USNRC, 1990), and the Maintenance Rule Regulatory Analysis (USNRC, 1991a).

A review of the failure rate data used in the NUREG/CR-4550 analyses indicated that the majority of the failures identified resulted from command faults in power or control circuits, not from hardware failure of the pumps and valves themselves. Table 1 provides the distribution of failure causes for failures modeled in the NUREG/CR-4550 analyses. Based on a review of the information in Table 1 and the relative contribution of various failures to the probability of core damage in the Surry PRA, it was estimated that approximately 30% of the core damage frequency associated with pump and valve failure resulted from hardware failure of the pump or valve.

An estimate of the possible reduction in core damage frequency that might result from the avoided pump and valve failures was made by a review of the Surry and Peach Bottom PRA accident sequences to determine the effect of the reduced pump and valve failure rates on core damage frequency.

An estimate of the possible reduction in the risk of public radiation exposure that might result from the avoided pump and valve failures was made using the estimated reduction in core damage frequency and dose conversion factors developed in previous regulatory analyses.

4. Estimation of Costs

An extensive cost estimate for implementation of the proposed revisions was not completed in this evaluation. The typical approach used by the USNRC in evaluating proposed new regulatory requirements is to first evaluate the potential safety benefits of the proposed change. The cost evaluation is prepared only if the safety benefits are determined to be significant.

The results of the safety benefit estimate indicate that the safety benefits associated with the proposed changes are not significant enough to

Table 1. Failure probabilities used in NUREG/CR-4550.

Component	Failure mode	Total probability	Contributors
Motor-driven pump	Failure to start	3.0E–3/d	2.5E–3 Circuit breaker command faults
			4.0E–4 Pump hardware faults
	Failure to run	3.0E–5/hr	No distribution of causes
Turbine-driven pump	Failure to start	3.0E–2/d	2.0E–2 Circuit breaker command faults
			1.0E–2 Pump hardware faults
	Failure to run	5.0E–3/hr	No distribution of causes
	Failure to remain open	1.0E–7/hr	No distribution of causes
Motor-operated valve	Failure to operate	3.0E–3/d	2.5E–3 Valve control circuit faults
			5.0E–4 Valve hardware faults
	Failure to remain closed	5.0E–7hr	No distribution of causes
	Failure to remain open	1.0E–7/hr	No distribution of causes
Air-operated valve	Failure to operate	2.0E–3/d	1.0E–3 Valve control circuit command faults
			1.0E–3 Valve hardware faults
	Spurious closure	1.0E–7/hr	No distribution of causes
	Spurious open	5.0E–7/hr	No distribution of causes
Solenoid-operated valve	Failure to operate	2.0E–3/d	1.0E–3 Valve control circuit command faults
			1.0E–3 Valve hardware faults
Hydraulic-operated valve	Failure to operate	2.0E–3/d	1.0E–3 Valve control circuit command faults
			1.0E–3 Valve hardware faults

proceed with a full cost analysis. For that reason, a complete cost analysis were not prepared. Some cost data on the current testing programs were collected during the plant visits in anticipation of the need to perform a complete cost analysis. These data are presented in EPRI Report TR 102240.

ASSUMPTIONS

The key assumptions that guided the evaluation are described below with justifications for their use:

1. All components were assumed to be properly designed and installed, and to have been initially capable of performing their design-basis safety functions in their undegraded state.

The purpose of inservice testing of pumps and valves is to assess their operational readiness. The goal of this testing is to identify degradation of the pumps and valves so that corrective actions can be taken, minimizing the occurrence of pump and valve failure during actual demands in response to accidents or transients. The purpose of this analysis is to estimate the potential benefits of the proposed revised inservice testing requirements in detecting degradation, as compared with testing performed under current inservice testing programs.

Assurance that the pump or valve is initially capable of performing its design functions is provided by the controls applied during design, manufacturing, installation, and startup testing. Many of the concerns regarding motor-operated valve (MOV) performance documented under Generic Letter 89-10 are related to the adequacy of initial MOV design, selection, or installation. This is a case where additional testing to augment the original startup testing has been prescribed by the USNRC to provide assurance of the initial capability of the equipment to perform its intended functions. However, this additional testing is beyond the intent of inservice testing requirements.

Estimation of the potential benefits of one-time testing to provide additional assurance of the initial capability of pumps and valves to perform their design basis functions was beyond the scope of this analysis.

2. Failure data used in USNRC sponsored probabilistic risk assessments are representative of the inservice failure behavior of pumps and valves that were initially capable of performing their design basis safety functions.

Data from the NUREG-4550 probabilistic risk assessments were used in performing this analysis. These assessments were selected because they are often used as reference analyses by the USNRC in evaluations of regulatory issues.

Other sources of component failure rate data exist in the industry, some of which may be more current or complete than those used in preparation of the NUREG-4550 analyses. An evaluation of other available sources of failure rate data was not undertaken. It is assumed that the failure rate and cause data used in the NUREG-4550 analyses reasonably represent the actual performance of properly designed and installed pumps and valves.

3. The additional testing necessary to satisfy the proposed inservice testing revisions will not result in degradation of the pumps or valves.

Repetitive testing at or near design-basis conditions would likely result in degradation of some of the components tested. However, this analysis assumed that no degradation would occur in order to maximize the estimated safety benefits of the proposed revisions and simplify the analysis.

4. No additional safety benefit will be realized for check valves, which are tested at essentially design-basis conditions in current inservice testing programs.

Inservice testing of check valves has been enhanced significantly over the last several years in response to USNRC concerns and The Institute

for Nuclear Power Operation (INPO) recommendations. Current testing includes valve closure, valve seating, and valve operation (fully opens and passes full flow). No further changes to check valve testing requirements would be anticipated if the proposed revisions were implemented; therefore, no additional safety benefit was attributed to the change case.

5. Safety relief valve failure rates would not be affected by the proposed revisions.

Current ASME Code inservice testing requirements for safety relief valves are comprehensive. No changes in testing requirements would be anticipated if the proposed revisions were implemented. No additional safety benefits were attributed to the change case.

6. Only active safety-related pumps and valves are of concern to this evaluation.

Testing of passive components is addressed by the inservice inspection program. Only active components are addressed in the inservice test program. Also, passive component failures are not a significant contributor to risk in most plant PRAs.

RESULTS

Surry Plant

The Surry NUREG/CR-4550 evaluation resulted in a mean core damage frequency from internal events of 4.0E–5 per year. Twenty-two accident sequences contributed to this total core damage frequency.

The estimated contribution of all valve and pump failures of interest to mean core damage frequency is 1.2E–6 per year, or 3% of the total mean core damage frequency.

The average dose conversion factor for the Surry NUREG-1150 analysis is 1.1E+5 person-rem per core damage event. The maximum population dose reduction that could be achieved through elimination of all modeled pump and valve hardware failures is then

1.2E–6 event/yr × 1.1E+5 person-rem/event
= 0.13 person-rem per year.

Peach Bottom Results

The Peach Bottom NUREG/CR-4550 evaluation resulted in a mean core damage frequency from internal events of 4.5E–6 per year. Eighteen accident sequences contributed to this total core damage frequency.

The estimated contribution of all valve and pump failures of interest to mean core damage frequency is 2.87E–7 per year, or 6% of the total mean core damage frequency.

The average dose conversion factor for the Peach Bottom NUREG-1150 analysis is 1.6E+6 person-rem per core damage event. The estimated reduction in population dose is then

2.8E–7 event/yr × 1.6E+6 person-rem/event
= 0.45 person-rem per year.

CONCLUSIONS

Hardware failures of pumps and valves are not significant contributors to the risk of core damage in the Surry and Peach Bottom NUREG/CR-4550 probabilistic risk assessments. Risks of core damage in these and many other PRAs tend to be dominated by major failures, such as loss of offsite and emergency power, and human errors, which result in equipment unavailability without actual hardware failure. Further, the number of hardware component failures that make a measurable contribution to the risk of core damage is small. Very few safety-related pumps and valves are associated with the great majority of the total contribution of all pump and valve failures to the core damage frequency.

This result implies that application of substantially increased inservice testing requirements to all safety-related pumps and valves may not be cost effective. An alternate approach that optimizes inservice testing requirements based on the

contribution of each pump or valve to the risk of core damage would be a preferred means of enhancing safety.

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Innovative Application of Probabilistic Risk Assessment Techniques to Limit Operating and Maintenance Expenses

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ABSTRACT

Utilities that run nuclear power plants are expending significant resources in responding to U.S. Nuclear Regulatory Commission Generic Letter 89-10 for testing motor-operated valves (MOV). Probabilistic risk assessment (PRA) can be used to determine the relative importance of different MOVs to allow management of resources. There is some concern that typical PRA analysis does not adequately address some issues with respect to MOVs, specifically MOV failure rate and common cause failures. This paper addresses several ways in which the PRA models and data can be adjusted to address these concerns.

INTRODUCTION

Most nuclear plants have recently completed an Individual Plant Examination (IPE) in response to the U.S. Nuclear Regulatory Commission (USNRC) Generic Letter (GL) 88-20. Most of them were completed with probabilistic risk assessment (PRA) models. Now that these models exist for each plant, they can be a useful tool for various purposes, including determining the appropriate application of resources commensurate with an item's safety significance (i.e., saving money). In this paper I will try to provide some ideas that can be applied with the current PRA models to evaluate the benefits of motor-operated valve (MOV) testing in particular, and also by extension, to other potential high-cost activities.

BACKGROUND

Most of you are familiar with GL 89-10 (USRNC, 1989), which requires utilities to perform significant analysis and testing for all safety-related MOVs. I'm sure you are also aware of rising operation and maintenance costs of nuclear plants and of various industry pressures to control costs with the intent of being more competitive to avoid extinction. And I'm sure you all recognize that some valves are more important than others, whether your measuring criterion is protection of the public or making power. With these considerations in mind, Illinois Power (IP) set about defining how we could address the concerns of GL 89-10 in the most cost-effective manner.

PRA CONCERNS

PRA provides a method of ranking components by their importance to risk, using several different measures. Appendix A provides a brief description of the construction of a PRA and how importance is measured.) You may think, then, that the prioritization of MOVs for GL 89-10 work would be a simple process once the PRA is done. There are, however, several concerns that complicate the picture. I'll discuss these concerns here, and then in the next section I'll describe one way that they can be addressed.

Failure Probabilities

The first issue is the estimation of MOV failure rates. As indicated, the estimation of valve failure rates is based on previous experience, generally a combination of your own plant's and industry collections. As valves are operated in the process of performing surveillances or in response to

system demands, in some cases they fail. The number of times a valve fails to stroke divided by the number of times it is challenged to stroke is the failure rate of the valve to stroke on demand. Of course data are not collected for each valve, but for classes of valves, such as all MOVs, for example, and for failure-to-open and failure-to-close separately. This number is typically on the order of 3E–3 to 8E–3 per demand. The issue here is, although the historical failure rate for valves is small (because they're always tested under nominal conditions), when an accident precursor occurs, the MOV will see much different conditions (pressure, flow, temperature, voltage, etc.). Therefore, past history cannot be a dependable indication of the reliability of the MOV under accident conditions.

One response to this condition may be to set the failure rate of all MOVs to a very high value—0.087, 0.1, or 0.5. The problem with an artificially large failure rate for MOVs is that it will inflate the perspective of the importance of MOVs. In the extreme, it could lead to a conclusion that pumps and operator actions are not important at all. This skewed perspective does not reflect actual plant conditions and is obviously not desirable. In addition, high failure rates make getting meaningful solutions to the PRA models very difficult.

Common Cause

In addition to the concern about what is the likely failure rate of valves under accident conditions, there is the concern that many valves could fail concurrently as a result of the postulated accident scenario. Because it is postulated that MOVs are, in general, under-designed and that an accident precursor could challenge them all, many MOVs could fail at once, disabling all injection systems, which would lead to core damage. As an illustration, if some event could fail valve A, valve B, and the normal supply valve in our example system (Appendix A, Figure A-1) all at once, the heat source could not be cooled. This is obviously of greater concern than if any one valve failed by itself.

Modeling Scope

While the PRAs are useful tools and model both safety-related and nonsafety equipment, there is a practical limit on the extent to which a plant can be modeled. This limit is determined to a large extent by judgment, considering the time and money that is available, the computing tool (both hardware and software) capabilities, and previous experience of those doing the modeling. Because of these limits, it could be argued that some important MOVs are not included in the PRA models.

Operating Modes

The IPEs were performed assuming that the reactor was initially operating at nearly full power. Consequently, they don't model well the potential risk from events that could happen while the reactor is shut down or in a refueling mode. Some studies (very expensive) have shown that the risk during shutdown is on the same order of magnitude as the risk from full-power operation. This raises the concern that maybe some MOVs that appear unimportant in the PRAs are really very important in some other plant operating mode.

ADDRESSING THE ISSUES

In the previous section, I identified four issues that challenge the use of PRA techniques to prioritize work on MOVs. In this section I will describe the actions taken at IP to address these issues. Some of them may be unique, but some may be considered common sense when I describe them. With this background, you may think of even better ideas.

Failure Probabilities

The first issue addressed was valve failure rates. The baseline MOV failure rate used for the Clinton Power Station (CPS) PRA was 3E–3 per demand for fail-to-open and fail-to-close. Various industry studies used failure rates from 1E–3 to 9E–3, but CPS concluded that 3E–3 was most appropriate, based on its use in NUREG CR-4550 (USNRC, 1990).

For the GL 89-10 evaluation, several steps were taken to assign more conservative values.

First, a conservative failure rate of 8E–3 was assigned as a minimum threshold for all valves to ensure that the generic failure rate was not understated. Raising the failure rate from 3E–3 to 8E–3 did not identify any more valves as important than were originally identified, other than those that were identified from symmetry in similar systems. With this threshold established, new MOV failure rates were established in three categories:

- Category 1: MOVs that will be fully modified and tested according to GL 89-10. A conservative threshold failure rate of 8E–3 was applied in both opening and closing directions, because we had essentially eliminated the failure mode of insufficient torque or settings under high hydraulic challenge conditions, and historical failure rates should be applicable.

- Category 2: Valves that were tested under high differential pressure in the Inspection and Enforcement (IE) Bulletin 85-03 (USNRC, 1985) program. As a result of IE Bulletin 85-03, many of the important MOVs in high-pressure injection systems, both high-pressure core spray and reactor core isolation cooling, had already had their torque and limit switches set and verified and had been tested in the opening direction under high pressure. For any of these MOVs not in Category 1, the failure rate in the opening direction was set to the threshold, 8E–3, because they have been demonstrated to open under high differential pressure. Failure rate in the closing direction was set as in Category 3, following.

- Category 3: All other MOVs modeled in the PRA. Conservative failure rates for both the opening and closing direction for the remainder of valves were assigned based on the following three factors:

1. The probability that the valve is out of its safety position when the safety function is required

2. The probability that the valve would be exposed to high differential pressure or flow when required to function

3. The probability that the valve would fail to function under the above differential or flow.

These three factors were multiplied together to obtain failure rates to apply to the valves in the PRA models. Each factor is developed in the following sections.

Factor 1

Many safety-related valves are installed to allow testing of various modes of the systems while the plant is operating. Consequently, they are normally in the position that supports the safety function and are only out of position for short intervals periodically, such as for stroke time testing or pump surveillance runs. For example, if a valve is out of position for 8 hours every quarter, then the probability that it is out of position when needed (when an accident precursor occurs) is

$$\frac{8 \text{ hr per test} \times 4 \text{ tests per yr}}{365 \text{ days per yr} \times 24 \text{ hr per day}} = 3.7\text{E}-3$$

Because this probability is lower than the threshold of 8E–3, 8E–3 was assigned as the failure rate in the PRA. Note that for this case, Factors 2 and 3 could be assigned unity without affecting the result.

On the other hand, some MOVs, for example, are installed to provide the capability to pump lake water into the reactor vessel as a backup cooling method. These MOVs are practically always shut, and Factor 1 is unity because these MOVs will always have to be opened to support the safety function during an accident.

Factor 2

This step of the analysis used as an input the design scenarios that had been used to develop the thrust requirements for the MOVs. We found that many of these scenarios were highly unlikely. I think the best way to describe this is to provide some examples.

Figure 1 represents two divisions of safety-related essential service water (SX). The design conditions for 1SX011A and 1SX011B (divisional cross-connection valves) should be able to operate under assumed cross-connected conditions with the Division 1 pump running with its loads all isolated, the Division 2 pump out of service with the Division 1 pump supplying its loads, the Division 1 pump at shutoff head and a pipe break in the Division 2 pump loads. At the outset, this case appears impractical—if the pump is at shutoff head, it must not be supplying any loads. However, for this analysis, it is assumed that such a case could occur. Then the question becomes, "How often could this be possible?" First, this system lineup can only be done during an outage or accident because the lineup is otherwise precluded by technical specifications. If it is assumed that the lineup could exist 1 week of an 18-month operating cycle, then the probability that the system is in this lineup when an accident initiator happens is about 1.3E–2. Even so, non-safety service water normally supplies both divisions of safety-related service water; therefore, it must be out of service, too, in order for this lineup to be of concern. Then, a conservative estimate for pipe breaks in this system is about 5E–5. Therefore, an upper bound for the fraction of time that these MOVs could see maximum challenge is about 7E–7. The generic failure rate of 8E–3 from all other causes is the overriding failure rate for these MOVs.

Figure 2 represents the cross-connection between safety-related essential service water (SX) and the residual heat removal (RHR) system for reactor flooding, MOVs 1E + 12–F094 and 1E + 12–F096. This analysis was based on the SX pump being at shutoff head, meaning that offsite power is available and the respective diesel is not running. In addition, the reactor must be at low-pressure. The fraction of low-pressure core damage events in which SX is available is about 0.11. Therefore, 0.11 was used as the challenge rate (Factor 2) for these valves.

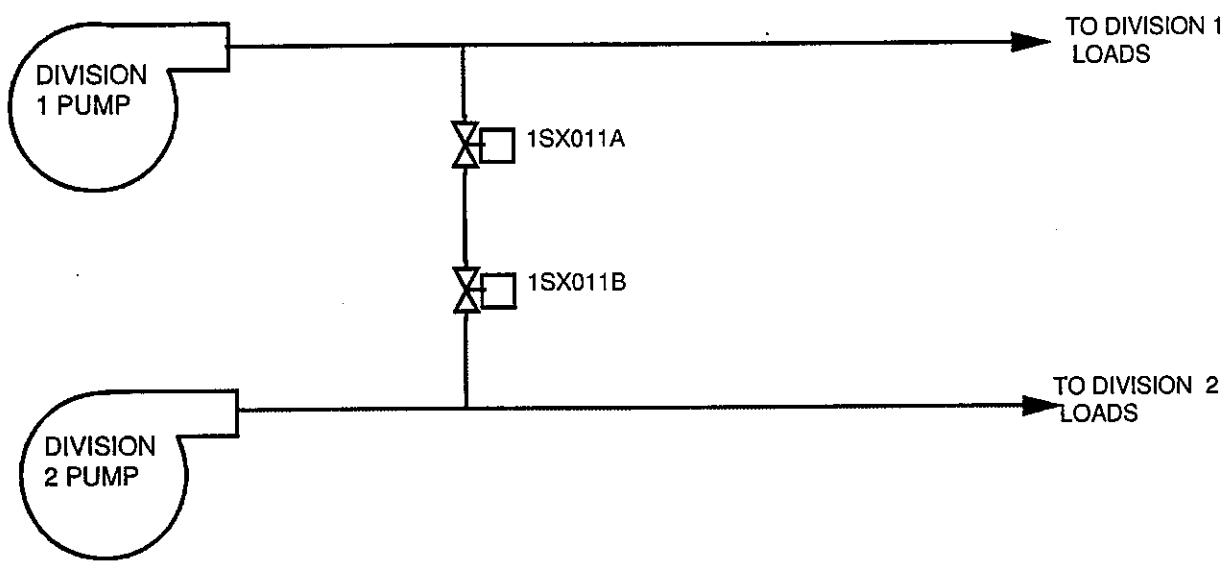

Figure 1. Safety-related service water cross-connection.

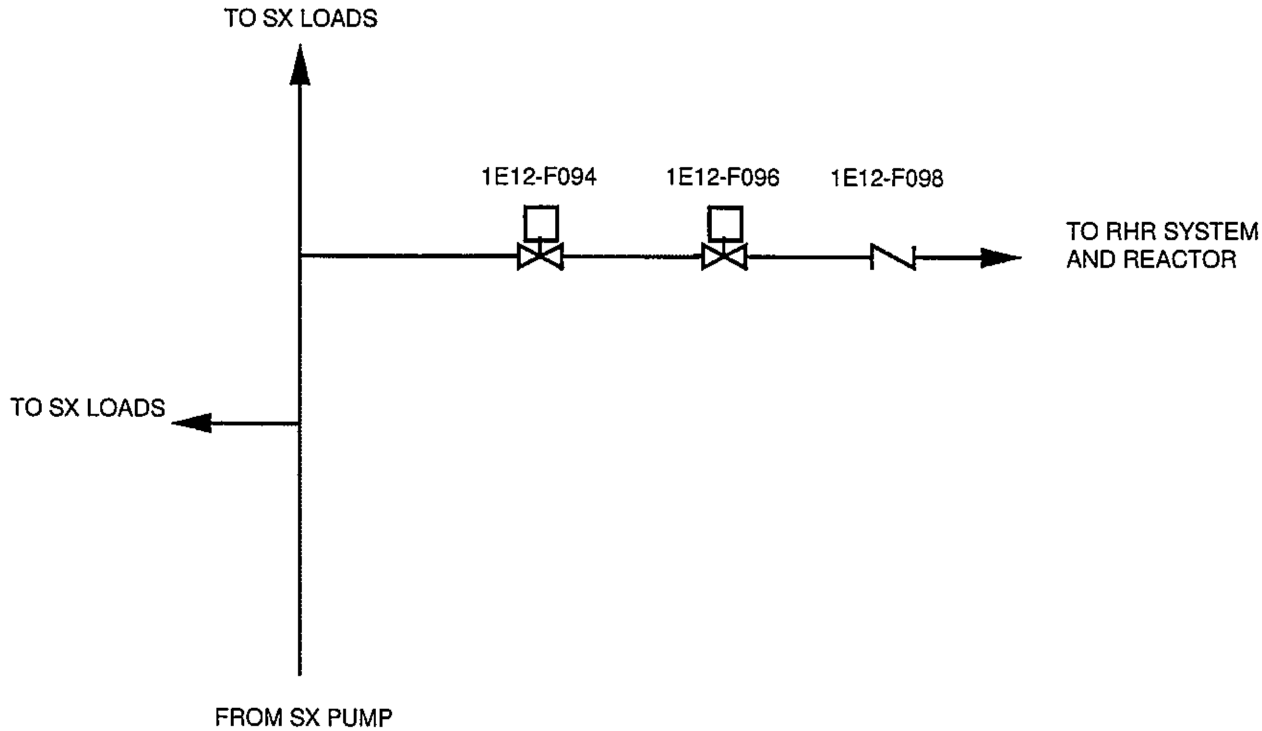

Figure 2. Safety-related service water cross-connection to residual heat removal.

Figure 3 represents the use of the RHR system in the shutdown cooling mode. The analysis is for the pump suction MOVs 1E+12–F006A and 1E+12–F006B (Division 1 and 2 RHR pump suction from the reactor, respectively) to be able to shut to isolate a potential drain-down path. 1E+12–F008 and 1E+12–F009 (shutdown cooling suction from reactor recirculation inboard and outboard valves) are assumed to be open with the reactor at maximum allowable pressure and level for shutdown cooling. Based on outage history, the plant is in shutdown cooling approximately 32% of the time (if these data include startup and initial cycles, the current value would be much less). The need to shut these MOVs could come from a pipe break or an operator error. While pipe breaks in this condition are very unlikely, operator errors were conservatively assumed to be likely (in spite of interlocks) and were assigned a value of 1.0 for this analysis. This yields a valve challenge rate (Factor 2) of 0.32. Note that the PRA was developed for full-power conditions, under which F006A/B, F008, and F009 would all be shut and their failure to shut would not appear in any PRA results. Because of the need to evaluate the importance of F006A/B, we developed this hybrid process, mixing full-power and shutdown configurations.

Figure 4 is a final example. This is the evaluation of a low-pressure injection system minimum flow valve to the suppression pool (1E+12–F064A/B). The evaluation is based on the pump being at maximum shutoff head, maximum containment pressure and suppression pool level, with a line break downstream. Neglecting the question of how the pump can be at shutoff head with this valve open, the probability of a pipe break in this line is about 1.5E–5 per year. The maximum containment pressure and suppression pool level occur during a large loss of coolant accident (LOCA) with the frequency of 1E–4 events per reactor year. The combined likelihood of high hydraulic challenge (Factor 2) on this MOV is 1.5E–9 per year.

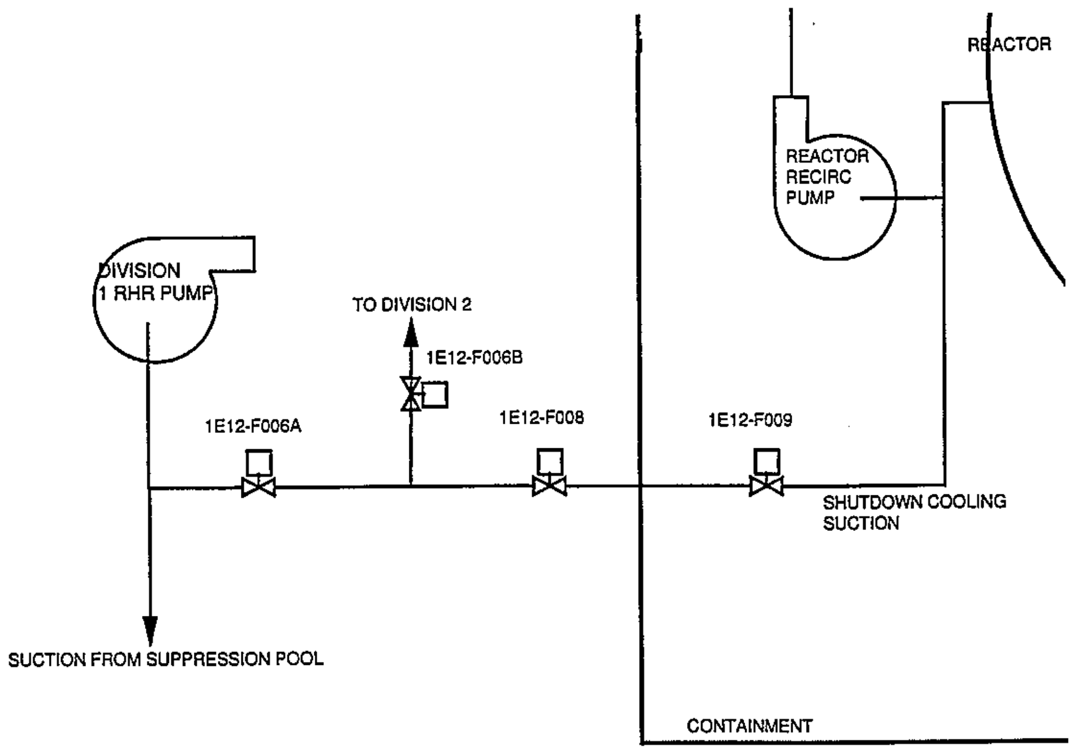

Figure 3. Shutdown cooling suction isolation.

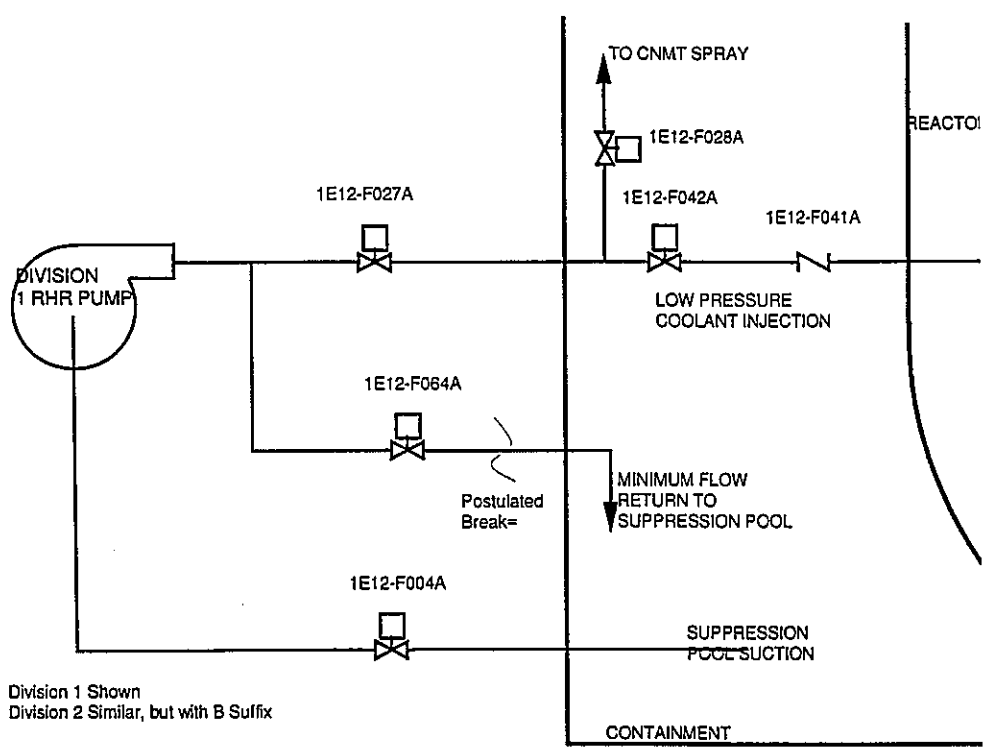

Figure 4. RHR minimum flow valve.

Factor 3

This probability was conservatively set to unity for the sake of this analysis. The case could be made that unity is too high, but as it turned out, when combined with Factors 1 and 2, this did not present a problem to the analysis or provide unreasonable results.

As indicated, if the product of Factors 1, 2, and 3 was less than 8E–3, the failure rate of 8E–3 was assigned. If the product was higher than 8E–3, the higher product was assigned. As a result, we had MOV failure rates assigned as high as 0.5, although most MOVs fill at the threshold value.

Common Cause

Similar to the finding for MOV failure rates, that the maximum challenges do not necessarily correspond to accident conditions, we found that accident conditions typically do not lead to common cause challenges. In fact, few scenarios could be postulated that could lead to high hydraulic challenges for many MOVs by the same event. In the process of reviewing the scenario-specific MOV failure rates, cases were identified in which different MOVs were challenged under the same conditions. About eight cases were identified. Figures 5 and 6 provide some examples.

Figure 5 indicates the MOVs that would be challenged if the RHR system were initially in the shutdown cooling mode. For each division, Valves 1E+12–F006A(B), 1E+12–F008, 1E+12–F009, and 1E+12–F053A(B) could be challenged by the same event (such as an operator error causing a flow diversion in the feedwater system, requiring a challenge to all these valves to shut). Therefore, an additional common cause event was added to each of these MOVs that fails them simultaneously. For this analysis, a simple Beta method (see Appendix A) of common cause analysis was used with Beta = 1.0.

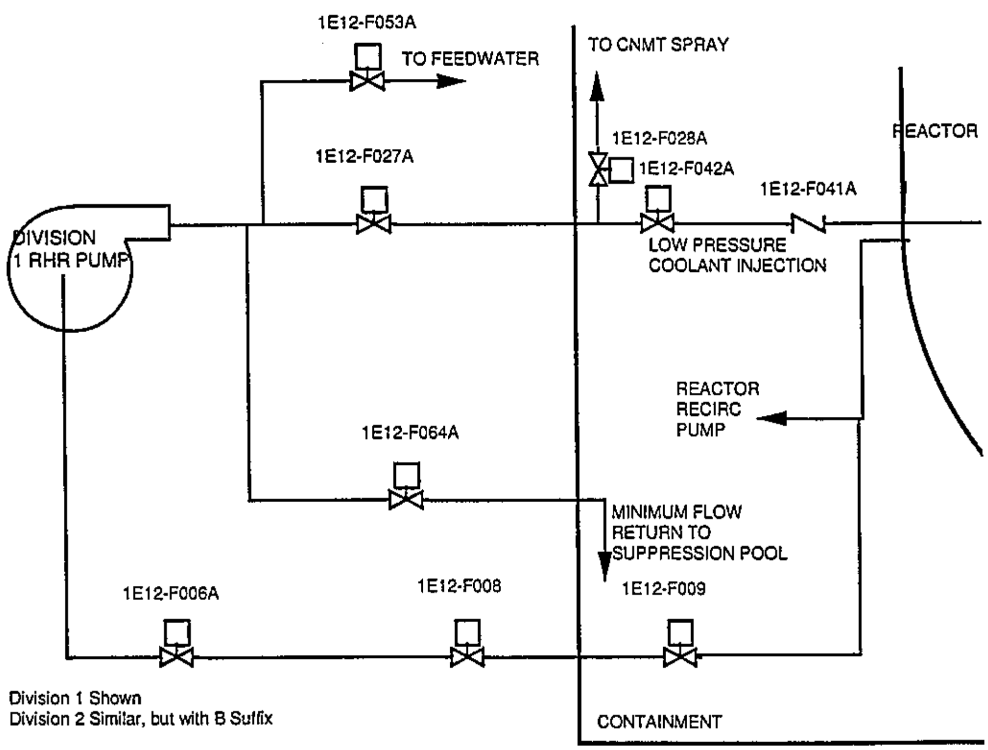

Figure 5. Shutdown cooling mode.

Figure 6 also shows RHR Valves 1E+12–F024A/B, 1E+12–F027A/B and 1E+12–F028A/B, which all require pump shutoff head for maximum challenge. An additional common cause event tying together the three MOVs in each division was added to the models, again with a Beta of 1.0.

Modeling Scope—Completeness

Initially, the PRA modeling scope was conservatively defined, based on including most of the equipment that must perform an active function to combat a potential accident, with its support functions, and passive piping system components that could plug. Based on advice from experienced consultants, certain equipment was not included, such as piping, closed vents and drains, and structures. The conservativeness of the original modeling was confirmed by the fact that of the 108 MOVs included in the models, 58 were not identified as important in any of the sensitivity analyses done for the GL 89-10 program. Nonetheless, an additional review was performed. Each of the safety-related MOVs that was not in the PRA model was reviewed individually to document the basis for its exclusion. This review did find one additional valve that was added to the model.

Another issue with respect to completeness is the extent of the analysis. If only core damage prevention is used for identification of valves, MOVs that maintain containment integrity or are important for severe accident mitigation would be missed. This shortcoming could be addressed by searching for important valves in the containment failure (Level 2 PRA) results. Because only a small fraction of core damage events lead to containment failure for CPS, very few MOVs are included in the Level 2 results. Therefore, it was decided to identify important valves for preventing core damage (Level 1 PRA results) and then separately address the functions of containment isolation, containment heat removal, containment venting, and containment/reactor flooding. These

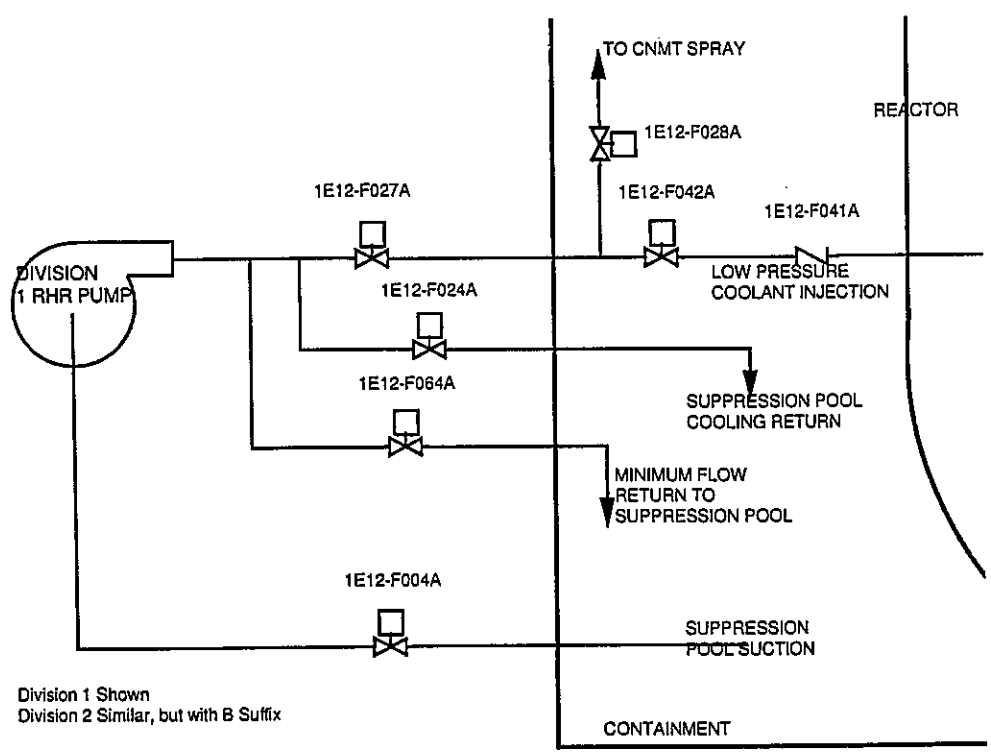

Figure 6. RHR common cause.

containment functions were evaluated with the fault trees that support the respective headings on the event trees. Any MOVs that appeared important in preventing core damage or any of the containment functions were identified as important for the GL 89-10 program.

Besides identifying MOVs based on their importance in all these cases, an additional review was performed to identify symmetrical MOVs. That is, if a given MOV appeared important in one train or system, but not in a similar train or system, the latter MOVs were also included in the GL 89-10 important population. Of course it should be noted that the PRA models were requantified from the beginning after the revised MOV failure probabilities and the new common cause groups were assigned. Had previous PRA results been used and modified with the new failure rates, MOVs that may not have appeared in results to this point, because of truncation levels, may still have been understated in importance. By re-quantifying the models from the beginning, no important MOV contributor could be lost because of truncation levels.

As an additional step in verifying completeness, we employed an expert panel made up of senior people from all departments. Four of the seven people on the team are current or former senior reactor operators. The team included representatives from operations and maintenance and training. This team was given the results of the PRA sensitivity studies and asked for their review, specifically to identify any other MOVs that they felt important or that we had identified as important that they felt were overstated. As a result of this review, two MOVs that were not well modeled in the PRA were identified.

Other Operating Modes—External events

Because the PRA is based on high-power operation and internal events only, it could be postulated that other valves could be important that had not been identified. This issue was addressed by a subjective review, with input from the expert panel, to identify what functions would be required in any other mode. We identified that if reactor inventory, heat removal, containment venting, and containment isolation were covered, core damage and containment failure could be averted in any operating mode. Valves to preserve these functions were already identified in the previous analyses.

A similar review was conducted to evaluate what functions would be required to address risks from external events, such as earthquakes and storms. It was concluded that these functions were also already covered.

SUMMARY

As a result of this analysis, IP was able to show, with confidence, that of the 230 safety-related MOVs in the GL 89-10 program at Clinton Power Station, only 50 were significant to risk—either to core damage or containment failure. Consequently, a lower priority could be placed on the modification and testing for the 180 valves that are not risk significant. This analysis not only allowed leveling the resources for GL 89-10 and spreading them over several years but also that less conservative assumptions may be used for the analysis associated with those valves. For example, a valve factor for Anchor Darling gate valves of 0.5 was used for the risk-significant MOVs, while a less conservative number may be used for the other MOVs. By extending the compliance interval, additional applicable testing results (from both CPS and other sources) may be factored into the analysis. Testing to date indicates that a number less than 0.5 is a value that represents the population of MOVs at CPS. By using the less conservative assumptions, several significant modifications may be eliminated. The importance ranking is also factored into the continuing verification over the life of the plant so that the less significant MOVs may be maintained at less cost.

OTHER APPLICATIONS

Gate Valve Concerns

A recent NRC document, "Special Study, Pressure Locking and Thermal Binding of Gate Valves," (USNRC, 1992) has brought up the issues of gate valve hydraulic locking and thermal binding. We have used a similar analysis for determining scenario-specific failure rates for the GL 89-10 valves, as identified above, to evaluate the valves that could be susceptible to these concerns. Then we determined the relative importance of the susceptible valves using the PRA.

Pumps

Similar analysis, of course, could also be performed for pumps. Additional factors, such as trading off time out-of-service for maintenance with probability of latent failure could be considered. Maybe we test pumps far more often than warranted (or less often than desired).

GLOSSARY

Event Tree—a graphical way of evaluating success or failure of systems (or operator actions) to mitigate the effects of an initiating event.

Sequence—a single path through an event tree representing a combination of successes or failures of the various event tree headings.

Fault Tree—logic diagrams for evaluating the contribution of components to potential failure of a system (or train or function).

Quantifying, Quantification—the process of reducing the event trees and fault trees to mathematical representations and solving for core damage and containment failure frequencies using Boolean logic and equipment failure probabilities.

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Appendix A

PRA Basics

Appendix A

PRA Basics

Probabilistic Risk Assessments (PRA) can be performed in a variety of ways, but most use some combination of event trees, fault trees, and cutsets. For those of you unfamiliar with these terms, I will explain with an illustration.

PLANT MODEL

Figure A-1 is a (very) simple model of a nuclear plant that I will use for illustrative purposes. In this model, there is a heat source inside the reactor vessel that must at all times be covered with water. There are three sources of water: the normal supply, System A, and System B. As you can see, System B has two pumps, while each of the other systems has only one; but System B has only one valve, like the other systems. The systems are designed such that the normal supply runs all the time and is adequate to keep the heat source covered. If the normal supply should fail, either System A or System B is adequate by itself to maintain the heat source covered. There is some possibility that the pipe loop connected to the reactor vessel could break. If it did, then two systems would be required to provide enough water to keep the heat source covered, but any combination of two of the three systems would be sufficient.

Event Trees

With that background, we can go on to the definition and description of an event tree. A simple definition of an event tree is a graphical way of evaluating success or failure of systems (or operator actions) to mitigate the effects of an initiating event. Figures A-2 and A-3 are example event trees. Figure A-2 is an event tree for the loss of normal supply event. Starting from the left, with

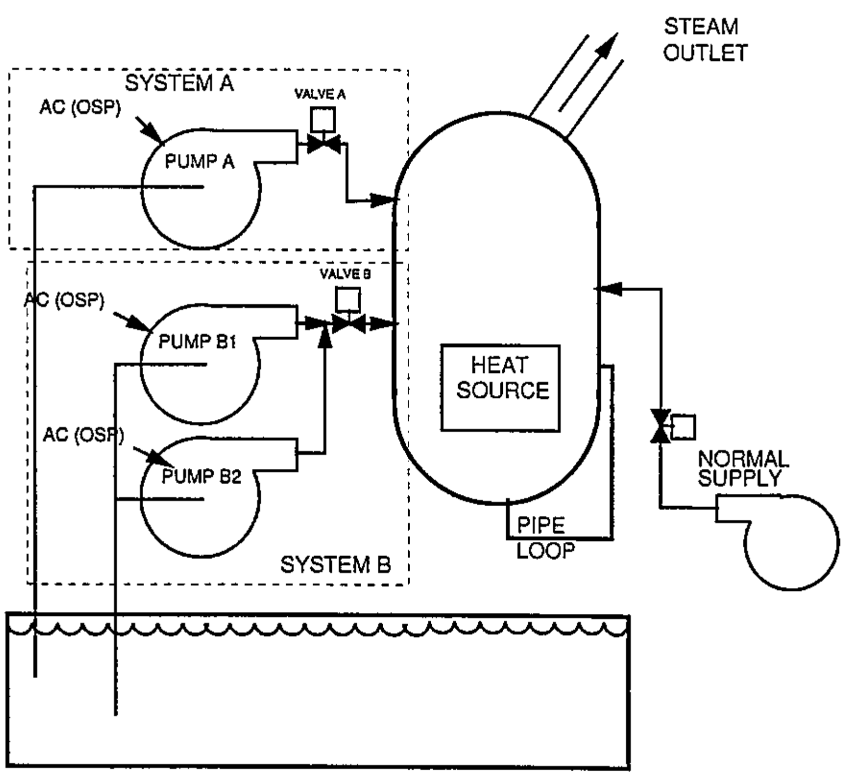

Figure A-1. Example systems.

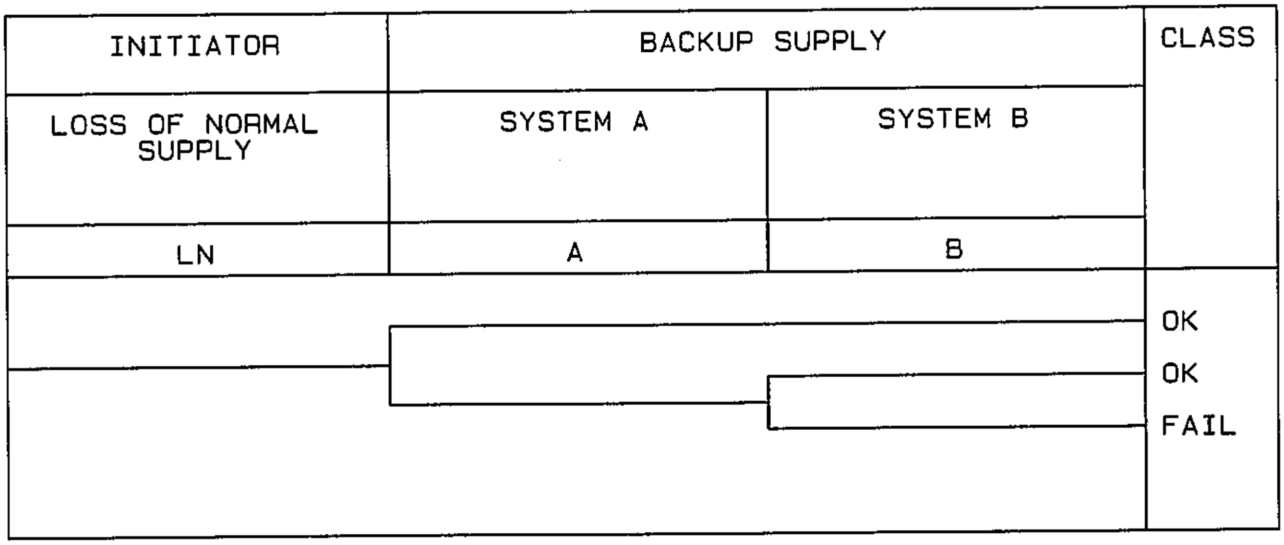

Figure A-2. Demonstration loss of normal supply.

the loss of normal supply heading (designated by LN), and moving right, the tree branches at System A. The up branch represents the case in which System A is successful. Following to the right, the sequence is labeled OK, meaning that in the LN event, with System A functioning, the heat source is covered. The down branch under System A leads to another branch under System B. The sequence taking the up branch here, System B successful, is also labeled OK. But the down branch, the sequence starting with LN and with both Systems A and B failing is a failure sequence. We'd like to know how likely that sequence is.

Figure A-3 is a similar tree for the event in which the pipe loop connected to the reactor vessel fails. If you follow the various sequences through this tree, you will see that all sequences in which there is success for any two systems are labeled OK. The others are labeled FAIL. We'd like to know how likely they are, as well as what are the major contributors to these failures.

Fault Trees

In order to determine the likelihood of any particular sequence, it is necessary to know how often the upper branch of an event tree should be taken, and how often the lower branch. In other words, we need to know the probability of failure of System A and System B. For this we use fault trees. Fault trees are logic diagrams for evaluating the contribution of components to failure of a system (or train or function). Figure A-4 is a sample fault tree for System B. It represents the various ways in which System B can fail. The funny shaped arrowhead pointing up to the label BSYSTOP, near the top of the tree, is called an OR gate. If any one of any number of inputs coming in from the bottom of the gate is a failure, the event above it will be a failure also. That is, if either BVALVEBMVO, "Valve B Fails to Open on Demand," or BGATE02, "Both Pump B1 and Pump B2 Fail to Provide Flow" are true (failure), the event BSYSTOP will be a failure. The rounded symbol under BGATE02 is called an AND gate. That means that all the inputs coming in from the bottom must be failures before the event above it is a failure.

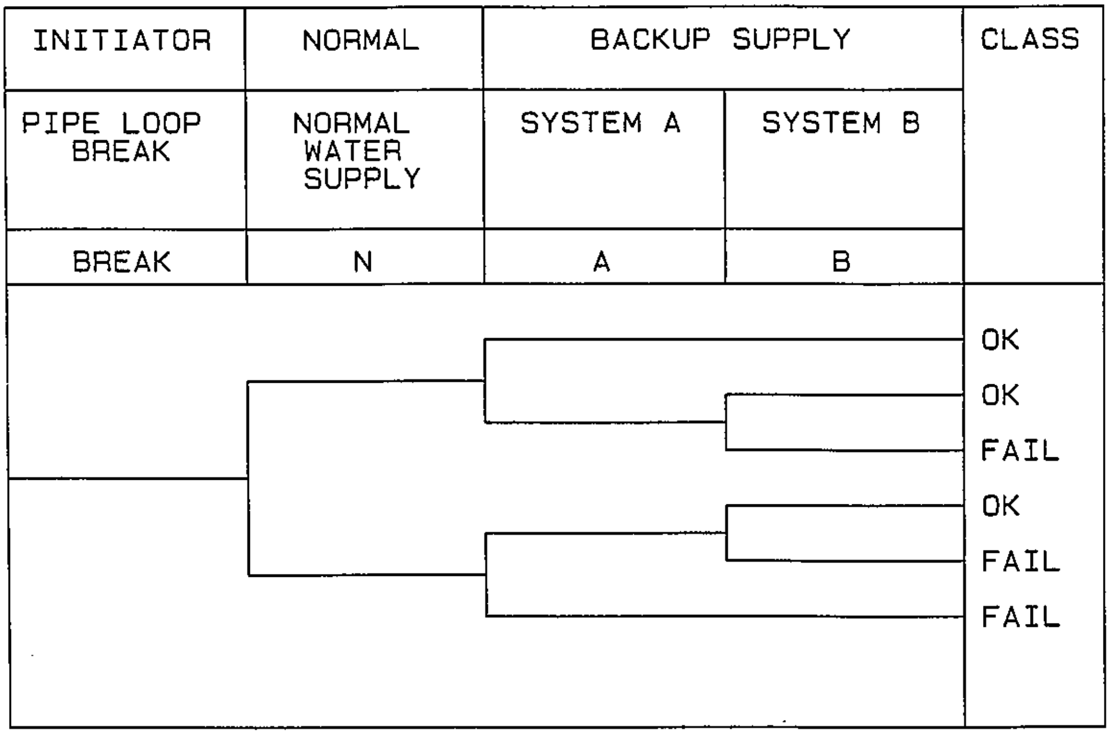

Figure A-3. Demonstration break.

From this discussion, it can be seen that several combinations of events can lead to failure of System B, BSYSTOP. For instance, if events BPUMPB1MPS (lower left center) and BPUMPB2MPM (lower right center) occurred simultaneously, BGATE02 would be a failure, leading to failure of BSYSTOP. On the other hand, occurrence of either BPWRSUPX (a transfer from an electric power fault tree that affects both pumps) or BVALVEBMVO, by itself, fails BSYSTOP. If we can assign probabilities to the various failures represented by the circle symbols on the figure, we can determine the probability of failure of System B, and the fraction of cases in which the lower branch on the event trees should be selected. Using the probabilities that have been arbitrarily assigned for illustration, the various combinations that can fail System B are listed in Table A-1. Then the probability of System B failing is the sum of the probabilities of all the ways that it can fail. This is the total (2.11E–1) shown at the bottom of the table.

This means that for either event tree (Figure A-2 or A-3) the fraction of cases in which the lower branch under the heading for System B should be taken is 0.211, and the fraction for the upper branch is (1–0.211) 0.789.

Failure Rates

The failure probabilities on Figure A-4 were trumped up for this example, but in order to determine risk of different events in your plant, you must estimate these failure probabilities for all the components and failure modes that are modeled. Typically, you will never have enough challenges and failures at your plant to assess these probabilities just from your plant data. You may have to use other sources that collect data from many plants and compare the data for similar equipment in order to assess, for example, the likelihood that a given pump will start when you turn the switch.

Table A-1. Combinations of events that can fail System B.

Case	Combination of events		Probability of combination
1	BPUMPB1MPS	BPUMPB2MPM	6.0E–2
2	BPUMPB1MPM	BPUMPB2MPM	3.0E–2
3	BPUMPB1MPR	BPUMPB2MPM	3.0E–2
4	BPUMPB1MPS	BPUMPB2MPR	2.0E–2
5	BPUMPB1MPS	BPUMPB2MPS	2.0E–2
6	BPUMPB1MPM	BPUMPB2MPR	1.0E–2
7	BPUMPB1MPM	BPUMPB2MPS	1.0E–2
8	BPUMPB1MPR	BPUMPB2MPS	1.0E–2
9	BPUMPB1MPR	BPUMPB2MPR	1.0E–2
10	BVALVEBMVO		1.0E–2
11	BPWRSUPX		1.0E–3
		Total (probability of B failure)	2.11E–1

Common Cause

There are several methods of accounting for common cause events in PRAs, but the simplest is called the Beta method. In this method, it is assumed that if one component were to fail, all other similar components would be more likely to fail because the first failure could be from some cause that could affect all similar components. In other words, the probability that all similar components fail at once is some simple factor times the probability of an independent failure of one component. This factor is termed Beta. If Beta is assumed equal to 1.0, then any time one component is assumed to fail, all similar components are assumed to fail simultaneously.

Importance Measures

Just from the example problem (looking at Figure A-1), you can intuitively conclude that failure of Valve B would have more impact on the likelihood of uncovering the heat source than, for example, failure of one of the B pumps. And you could probably conclude that failure of Valve B has more impact than failure of Valve A. If Valve A failed at the same time as Pump A, its failure would have no consequence, while failure of Valve B concurrent with failure of Pump B1 would still be significant because it would prevent water from Pump B2 from getting to the heat source.

With a bigger model, you would not be able to rank the relative importance of components just by inspection. One way to measure importances is illustrated using Table A-1. The percent of the total failures in which a particular event participates gives a measure of importance. For example event BPUMPB1MPS occurs in combinations 1, 4, and 5 with a total contribution of (6.0E–2 + 2.0E–2 + 2.0E–2) 1.0E–1. This divided by the total failure of 0.193 yields 52%. On the other hand, event BVALVEBMVO occurs in only combination 10, with a contribution of 1.0E–2, or 5% of the total failure. When a table similar in structure to Table A-1 is constructed to represent all the failure sequences in all the event trees, then the relative importance of all the basic events in Systems A, B, and the normal supply can be compared. Most PRA software calculates the relative importance of various components. The importance can be measured in many ways, but the description of the different importance measures is beyond the scope of this discussion.

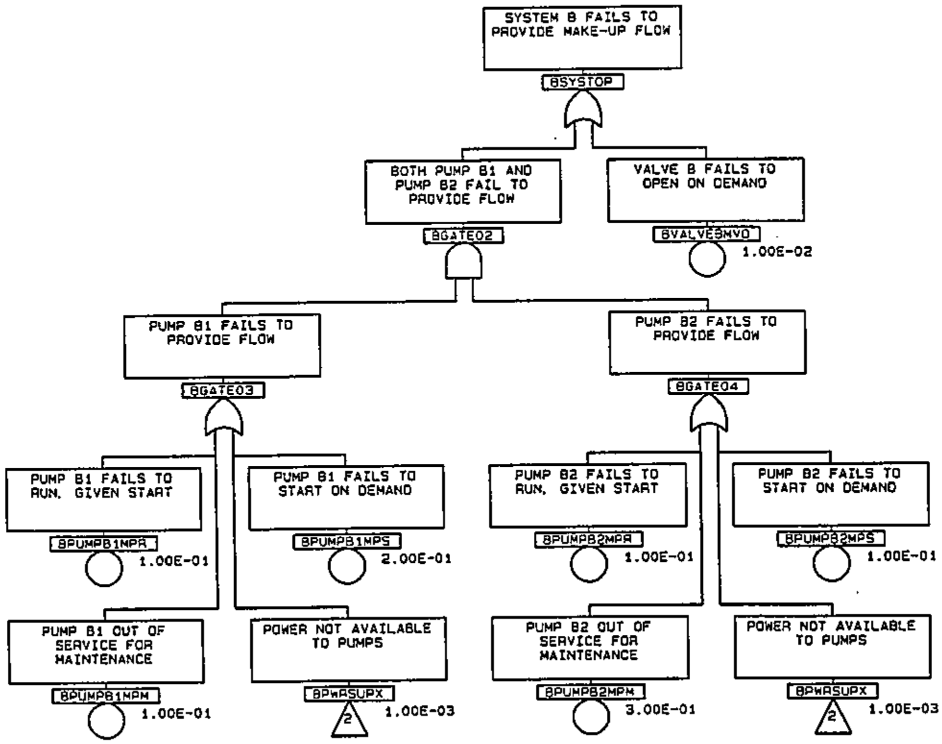

Figure A-4. Simple system fault tree example.

Equipment Modeled

A useful feature of PRAs is that they include both safety-related and nonsafety components. It is not unusual to find that some nonsafety equipment at a given plant is actually more important in preventing core damage than some of the safety related equipment.

The above discussion was intended to be a very quick overview of PRA methods. Any PRA practitioner at your plant can provide any amount of additional detail that you may need. In particular, the amounts of detail included in fault trees and event trees vary, but the result is typically similar—various sequences leading to core damage. Each of these sequences has a unique expected frequency of occurrence, and when they are taken together, the result is the estimated risk of core damage. Each method also has some way to evaluate the relative contributions of various pieces of equipment.

Ranking of Risk Significant Components for the Davis-Besse Component Cooling Water System

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ABSTRACT

Utilities that run nuclear power plants are responsible for testing pumps and valves, as specified by the American Society of Mechanical Engineers (ASME) that are required for safe shutdown, mitigating the consequences of an accident, and maintaining the plant in a safe condition. These inservice components are tested according to ASME Codes, either the earlier requirements of the ASME Boiler and Pressure Vessel Code, Section XI, or the more recent requirements of the ASME Operation and Maintenance Code, Section IST. These codes dictate test techniques and frequencies regardless of the component failure rate or significance of failure consequences. A probabilistic risk assessment or probabilistic safety assessment may be used to evaluate the component importance for inservice test (IST) risk ranking, which is a combination of failure rate and failure consequences.

Resources for component testing during the normal quarterly verification test or postmaintenance test are expensive. Normal quarterly testing may cause component unavailability. Outage testing may increase outage cost with no real benefit. This paper identifies the importance ranking of risk significant components in the Davis-Besse component cooling water system. Identifying the ranking of these risk significant IST components adds technical insight for developing the appropriate test technique and test frequency.

INTRODUCTION

Risk analysis studies, equipment failure databases, equipment histories, completed test data, operational analysis, and expert opinion can assist in identifying the likelihood of failure or the severity of consequences for components in nuclear power plants. Risk has been defined as the measure of the potential for harm or loss that reflects both the likelihood of failure (e.g., failure frequency) and severity of consequences (e.g., adverse effect to health, property, or environment). Risk may be the product of likelihood of failure and severity of consequences. Overall risk is dependent on what the owner will accept according to expert judgment, the insurer, or the regulator. Risk can be calculated and evaluated using engineering techniques.

Evaluation of risk can be used to justify the test technique or test frequency. It can also be used as the basis for design, reevaluation of safety significance, self audits, and by the regulators for inspections. Risk is being considered for its usefulness in several fields, such as regulatory compliance and maintenance (NUMARC, 1992).

This paper demonstrates the use or risk-based analysis techniques to establish a process for identifying the inservice testing (IST) or preventive maintenance levels for the Davis-Besse Nuclear Power Plant component cooling water (CCW) system.

ASME RISK-BASED INSERVICE TESTING RESEARCH

A detailed methodology has not yet been established for risk-based IST of light-water nuclear power plants as it has for inservice inspection (ASME, 1992). This paper provides an investigation of useful risk-based techniques for IST. At present, the American Society of Mechanical Engineers (ASME) Center for Research and Technology Development is working on the development of a "Risk Based Inservice Testing Guidelines Document." The author is a member of this research task force. It is intended that this "Risk-Based Inservice Testing Guidelines Document" will serve as the methodology basis for the development of future ASME Code IST requirements. At this time the author believes that the NRC will not accept probabilistic risk assessment (PRA) as the sole basis for relief from ASME IST requirements, but will also require a complementary deterministic analysis.

RISK RANKING OVERVIEW

The qualitative risk-based ranking matrix (Figure 1) is adapted from the State of California's guidance (Lercari, 1989) for the preparation of a risk management and prevention program. It is the basis for development of risk values. This qualitative risk-based ranking matrix represents a likelihood of failures versus the severity of consequences. An IST component (and a preventive maintenance structure, system, or component) may be defined on this matrix. The probability of failure is plotted on the Y axis, while severity of consequence is plotted on the X axis. Severity of consequence may be called the importance factors. Different risk rankings or levels can be defined on a matrix plot. A visual representation on the matrix would represent the relative risk of a component when compared with all components.

The owner should focus IST (or increased preventive maintenance) on those components that fall into the upper right matrix because these are high safety risk events. Target values for risk may be defined on the matrix.

The ability to develop a qualitative risk-based ranking matrix for inservice components with known failures and importance factors would allow the reallocation of IST, thus leading to the reduction of the probability of accidents by increasing the reliability of components.

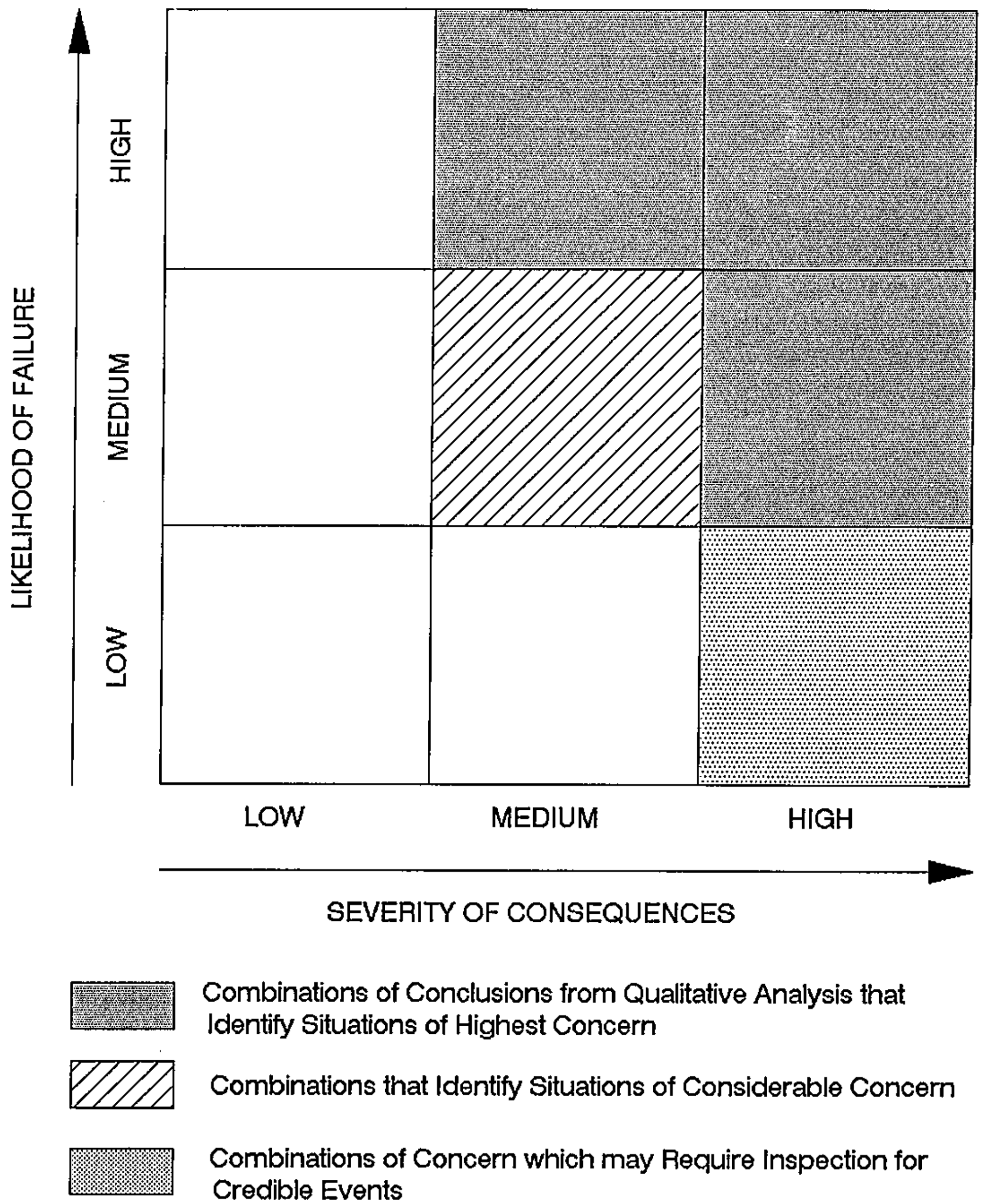
COMPONENT COOLING WATER SYSTEM OVERVIEW

Safety-related components are those required to shut down the reactor to a safe shutdown condition, maintain the reactor in the safe shutdown condition, or to mitigate the consequences of an accident. A majority of required testing at nuclear power plants is for safety-related components.

Nonsafety-related components may not be nuclear safety issues, but could still induce equipment damage, personnel injury, or replacement power cost. A nonsafety-related component failure could cause significant challenges to safety-related systems.

The purpose of the CCW system is to remove nuclear decay heat or provide heat removal support from other essential equipment so that a safe shutdown environment is maintained. The CCW system is an essential system. During a reactor shutdown decay heat is still produced at approximately 7% of previous power levels. If the decay heat is not removed, fuel damage could occur. The CCW system is the one of three safety trains designed to remove this heat. The CCW system transfers heat from the reactor coolant system via the decay heat system to the environment via the service water system.

The CCW system consists of two essential closed cooling loops. These loops supply CCW system water to essential and nonessential components. Both loops are redundant and independent. There are component interlocks and administrative procedures to ensure this independence.



*Adapted from State of California's Guidance for the preparation of a Risk Management and Prevention Program by Lercari (1989), which was modified from EPA Technical Guidance for Hazards Analysis (1987).

Figure 1. Qualitative risk-based ranking matrix.

Each independent essential CCW system loop removes heat from

- Decay heat removal coolers
- Essential pump bearing and oil heat exchangers
- Containment gas analyzer
- Emergency diesel generators.

The essential decay heat sinks to the service water system are two of three available CCW system heat exchangers. The third CCW system heat

exchanger is an installed spare and can be aligned to either essential loop. These CCW system heat exchangers remove heat from the above components. The heat is transferred to the service water system and then routed to the environment.

The CCW system supplies water to nonessential loads located inside the containment structure and radiation control area. These nonessential loads will be isolated automatically during an accident condition. The valves to containment will automatically close to ensure proper containment integrity and maintain CCW system integrity. The valves serving nonessential loads in the radiation control area will also automatically close to ensure proper CCW system integrity.

During normal plant operation the CCW system also supplies nonessential loads. If CCW system flow to a nonessential component were terminated, a forced plant shutdown could occur. These transients have been analyzed and would not cause an unsafe condition.

An example of a loss of CCW system to a nonessential component causing a plant shutdown is isolation of all flow to the control rod drive heat exchangers. For continued reactor power, all safety and regulator control rods must be maintained in a withdrawn position. To accomplish this, a mechanism must be latched by an electromagnetic field onto a screw rod connected to the control rod. This field, when energized, will keep the control rods latched and retained. Field coil heat is generated and nonessential CCW system flow is required to remove this heat. If CCW system flow is inadvertently lost, the control rod will overheat, causing the control rod drive (CRD) power to be removed. Upon CRD power removal, the rods will become unlatched and gravity will let them fall into the reactor, hence creating a fail-safe condition. Because this system is fail-safe and not expected to function during an emergency, it is considered nonessential. During a forced reactor shutdown, control room operators are instructed to ensure that all control rods are properly inserted into the reactor; this act will verify subcriticality.

An example of a loss of CCW system to a nonessential component that does not cause a plant shutdown is isolation of all flow to the boric acid evaporator. These evaporators separate reactor coolant into boric acid and high-quality distilled water. CCW system cooling flow is supplied to the boric acid evaporator's condenser. The water and acid are recycled back to the reactor coolant system to chemically control reactivity. Loss of CCW system to a boric acid evaporator is only an inconvenience; other systems can replace this temporary loss of water and acid.

CCW SYSTEM BOUNDARIES

This study is limited to the CCW system. This system is appropriate for investigation because of the number of previous reviews, significant operational expedience, identified failures, and independent study. The CCW system is large enough to give an adequate component sample representation. Attachments 1 and 2 contain a list of components that will be addressed. This study contains approximately 47 valves and 31 pumps or heat exchangers. These component types and faults are repeated to some extent because the CCW system contains two independent and redundant loops. Figure 2 is a schematic drawing of the CCW system. The scope will be limited to the CCW system components that are required for safe shutdown or, if failed that would cause a plant transient. One or two components that have no effect on safety will be evaluated to ensure that a low- or no-risk value is identified on the qualitative risk-based ranking matrix (Figure 1).

DEVELOPMENT OF RISK RANKING MATRIX

The process requires defining the individual components (pumps and valves) for the safety system. These IST components are defined by the owner according to the scope statements of ASME Boiler and Pressure Vessel, Section XI, and Operations and Maintenance (OM), Section IST, Codes.

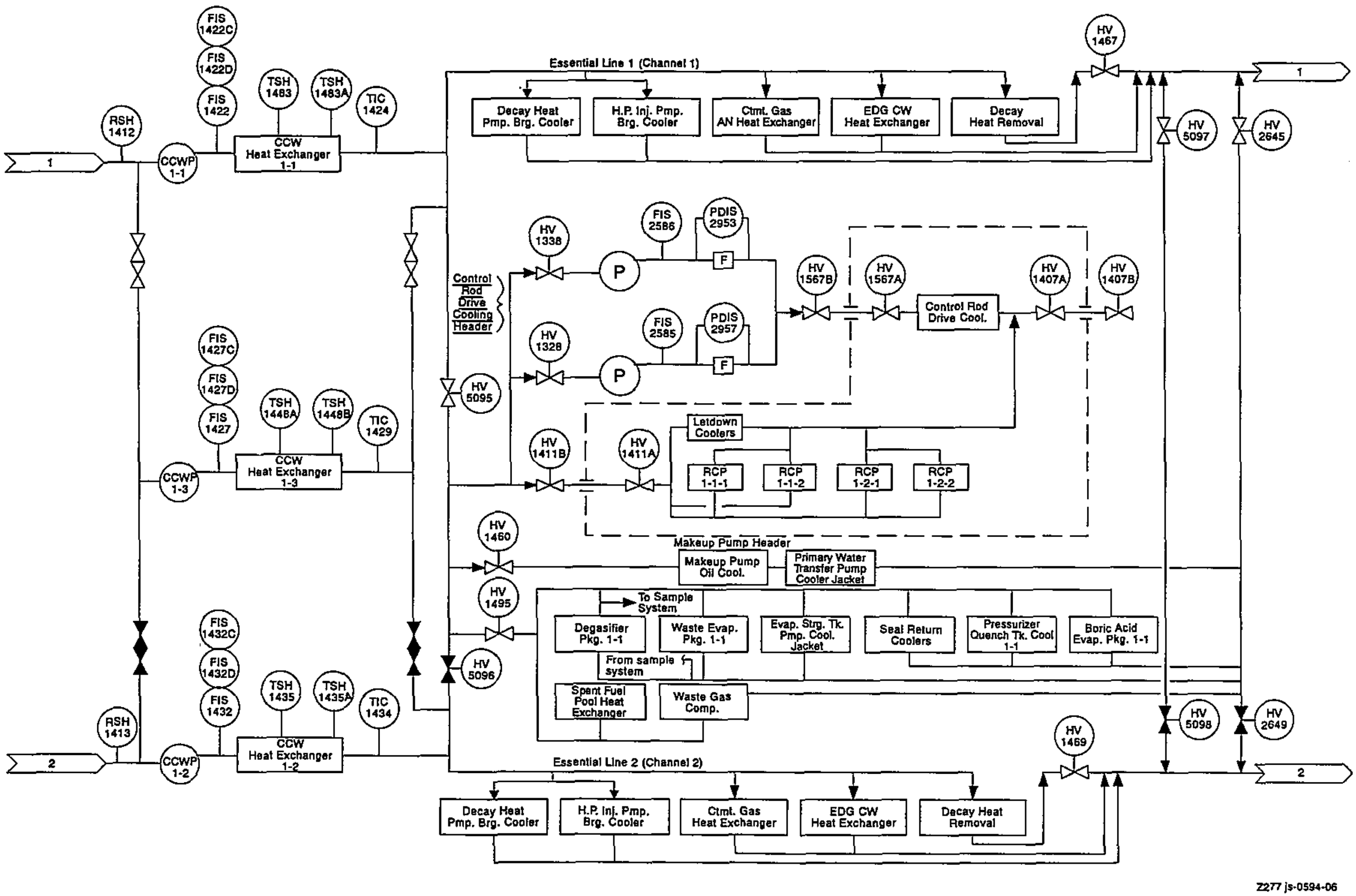


Figure 2. Component cooling water system schematic.

First, identify and rank the failures for the CCW system components. Obtain quantitative values for likelihood of failure. These values may be found in the owner's PRA. However, these values are not likely to be plant specific—generic values are normally used.

Second, develop the CCW system fault tree for the PRA to obtain importance factors. I am presently evaluating Davis-Besse's PRA fault tree for the CCW system. The CCW system fault tree was developed using system descriptions, design documentation, and expert opinion. All IST components should be identified within the fault tree. Component logic should be included. A fault tree analysis is required to obtain the severity of consequences or the importance factors for each IST component. Importance factors may be Birnbaum's Importance, Fussel-Vesely Importance, Risk Achievement Worth, or Risk Reduction Worth. These importance factor values are not attached, because they are being developed and finalized at this time.

Third, develop a qualitative risk-based ranking matrix (similar to Figure 1) for the CCW system based upon each component probability of failure and their importance factors. These matrices would be associated with safety risk.

LIMITED CONCLUSIONS

Investigation of the plant-submitted PRA as compared with the current IST program indicates some differences. Although PRAs were required by U.S. Nuclear Regulatory Commission Generic Letter 89-20, these PRAs are very difficult to update, while the IST program is safety driven to change. IST programs must be updated as plant design changes or after revised design basis and audit reviews occur. PRA programs are not required by regulation to be updated. An updated PRA is said to be a living PRA. Therefore, expect differences between the PRA and IST component databases.

PRA failures may be evaluated on the system or subsystem level, while IST addresses individual components. Hence, one may not find a specific IST component explicitly within the PRA. The PRA may need modification to address all individual IST components explicitly.

The PRA database is extensive compared with the IST program. A typical PRA encompasses approximately 3,000 components. A typical IST program contains approximately 500 pumps and valves. This difference implies approximately 2,500 components that are not required for a risk-based IST evaluation. Fault trees developed with many components require large computer-based programs and are very time consuming.

There are many PRA computer-based programs, such as CAFTA (SAIC, 1989), yet there are no standard databases nor evaluation criteria to ensure that risk importance is evaluated correctly. This practice should be standardized so databases can be used with different PRA software. This discrepancy concerns regulators and end-users.

Overall risk ranking does not necessarily need to reflect current PRA core damage frequency. A top event failure probability should not be a primary concern for IST. The focus should be on the relative ranking of the IST components.

IST based upon quantative risk is new. Overall acceptance is still required, among both industry and regulators. Many owners feel that risk-based IST programs will cause them to test high-risk-significant components more, with no relief from the low-risk-significant components. A statement of purpose or policy for future risk-based IST testing or acceptance from the regulators is needed to enhance risk-based IST program developments.

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Attachments 1 and 2

Component Cooling Water Valves Required for Safe Shutdown

Component Cooling Components Required for Safe Shutdown

Attachment 1

Component Cooling Water Valves Required for Safe Shutdown

Valve number	Type	Actuator	Valve description
CC17	CK	SA NA	CCW pump discharge line check valve.
CC18	CK	SA NA	CCW pump discharge line check valve.
CC19	CK	SA NA	CCW pump discharge line check valve.
CC127	SC	SA NA	Makeup Pump 1-1 nonessential isolation check valve.
CC128	SC	SA NA	Makeup Pump 1-2 nonessential isolation check valve.
CC129	SC	SA NA	CCW cooling return from makeup Pump 1 to CCW Loop 1.
CC130	SC	SA NA	CCW cooling return from makeup Pump 2 to CCW Loop 2.
CC148	SC	SA NA	Bearing cooling water inlet to decay heat Pump 1-1.
CC149	SC	SA NA	Bearing cooling water outlet from decay heat Pump 1-2.
CC151	SC	SA NA	Bearing cooling water outlet from decay heat Pump 1-1.
CC153	SC	SA NA	Bearing cooling water outlet from decay heat Pump 1-2.
CC183	SC	SA NA	CCW inlet to RCS Pump thermal barrier line check valve.
CC256	SC	SA NA	CCW cooling from Loop 1 for makeup Pump 1.
CC263	SC	SA NA	CCW cooling from Loop 2 for makeup Pump 2.
CC283	CK	SA NA	CCW inlet to RCS pump thermal barrier line check valve.
CC383	CK	SA NA	CCW inlet to RCS pump thermal barrier line check valve.
CC483	CK	SA NA	CCW inlet to RCS pump thermal barrier line check valve.

Valve number	Type	Actuator	Valve description
CC532	CK	SA NA	CCW pump discharge header isolation check valve.
CC533	CK	SA NA	CCW pump discharge header isolation check valve.
CC1328	GT	MO AI	CCW inlet to CRDC booster pump block valve.
CC1338	GT	MO AI	CCW inlet to CRDC booster pump block valve.
CC1407A	BF	MO AI	CCW return from letdown cooler containment isolation valve.
CC1407B	BF	MO AI	CCW return from letdown cooler containment isolation valve.
CC1409	GT	MO	CCW to inlet of the letdown cooler
CC1410	GT	MO	CCW to inlet of the letdown cooler
CC1411A	BF	MO AI	CCW to letdown coolers
CC1411B	BF	MO AI	CCW to letdown cooler containment isolation valve.
CC1460	GL	AO C	CCW to nonsafety-related loads isolation valve.
CC1467	BF	AO O	DH HX CCW outlet line isolation valve.
CC1469	BF	AO O	DH HX CCW outlet line isolation valve.
CC1471	BF	AO O	DG jacket cooling water HX CCW outlet line isolation valve.
CC1474	BF	AO O	DG jacket cooling water HX CCW outlet line isolation valve.
CC1495	BF	AO C	CCW to nonsafety-related loads isolation valve.
CC1567A	GT	MO AI	CCW inlet to CRD cooling containment isolation valve.
CC1567B	GT	MO AI	CCW inlet to CRD cooling containment isolation valve.
CC1643	RL	SA NA	CCW surge tank relief valve.
CC2645	GT	MO AI	Nonsafety-related CCW return line isolation valve.
CC2649	GT	MO AI	Nonsafety-related CCW return line isolation valve.

Valve number	Type	Actuator	Valve description
CC3602	RL	SA NA	CCW surge tank relief valve.
CC4100	GL	MO AI	RCS pump CCW outlet line block valve.
CC4200	GL	MO AI	RCS pump CCW outlet line block valve.
CC4300	GL	MO AI	RCS pump CCW outlet line block valve.
CC4400	GL	MO AI	RCS pump CCW outlet line block valve.
CC5095	GT	MO AI	CCW pump discharge header cross-tie line block valve.
CC5096	GT	MO AI	CCW pump discharge header cross-tie line block valve.
CC5097	GT	MO AI	Letdown cooler return to CCW line block valve.
CC5098	GT	MO AI	Letdown cooler return to CCW line block valve.

Attachment 2

Component Cooling Components Required for Safe Shutdown

Component number	Type	Description
P43-1	CCW pump	CCW for pump Loop 1
P43-2	CCW pump	CCW for pump Loop 2
P43-3	CCW pump (spare)	CCW for pump Loop 1 or Loop 2
E22-1	CCW heat exchanger	Primary heat sink for Loop 1
E22-2	CCW heat exchanger	Primary heat sink for Loop 2
E22-3	CCW heat exchanger (spare)	Primary heat sink for Loop 1 or Loop 2
E27-1	DH heat exchanger	Primary heat source for Loop 1
E27-2	DH heat exchanger	Primary heat source for Loop 2
EDG 1	EDG cooling jacket	Emergency diesel cooling and CCW Loop 1 minimum recirculation flow path
EDG 2	EDG cooling jacket	Emergency diesel cooling and CCW Loop 2 minimum recirculation flow path
E198-1	High-pressure injection pump exchanger	High-pressure injection pump oil bearing cooler for Loop 1
E198-2	High-pressure injection pump exchanger	High-pressure injection pump oil bearing cooler for Loop 2
P42-1	Low-pressure injection pump	Low-pressure injection pump bearing housing cooler for Loop 1
P42-2	Low-pressure injection pump	Low-pressure injection pump bearing housing cooler for Loop 2
A5027	Containment gas analyzer heat exchanger	Measure hydrogen concentration during a LOCA condition for Loop 1
A5028	Containment gas analyzer heat exchanger	Measure hydrogen concentration during a LOCA condition for Loop 2
E212-1 E198-1	Makeup pump Lube oil and gear lube cooler	Provides cooling to the makeup Pump 1 oil system.
E212-2 E198-2	Makeup pump Lube oil and gear lube cooler	Provides cooling to the makeup Pump 2 oil system.
P170-1 P170-2	CRD booster pump[a] CRD booster pump[a]	Nonessential pumps that ensure proper flow to the CRDs
F55-1 F55-2	CRD filter[a] CRD filter[a]	Filter CCW to the CRD coolers
E25-1 E25-2	Letdown Cooler[a] Letdown Cooler[a]	Cool RCS prior to entering the letdown system

Component number	Type	Description
P36-1	Reactor coolant pump cooler[a]	Each RCP has four coolers; they are motor, upper motor bearing, lower motor bearing, and seal cooler
P36-2	Reactor coolant pump cooler[a]	
P36-3	Reactor coolant pump cooler[a]	
P36-4	Reactor coolant pump cooler[a]	
E26-1	Seal return coolers[a]	RCP seal return has a dedicated return flow path.
E26-2	Seal return coolers[a]	

a. These components are not required for safe reactor shutdown, but have the potential to cause a plant transient.

Applying Risk-Based Methods to Inservice Testing

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ABSTRACT

Nuclear plants recognize the value of inservice testing (IST) of pumps, valves, and other safety-related components, but often spend large amounts of resources testing components of relatively little safety impact. Until the emergence of probabilistic risk assessment (PRA) as an accepted procedure, there was no easy method to quantitatively rank the importance of components. This paper addresses the ways that PRA techniques can be applied to IST in a way that focuses the testing on those components most critical to the safety of the plant, while at the same time reduces the amount of resources (and costs) required to have an effective IST program.

INTRODUCTION

Utilities are continually searching for ways to reduce operations and maintenance (O&M) costs, particularly where such costs appear to have little value in improving the safety or reliability of a nuclear power plant. The inservice testing (IST) program is one area where the application of risk-based methods may reduce or eliminate testing of pumps or valves that are marginal to safety. Requirements for IST are defined by the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, and the ASME Operations and Maintenance Code, Section IST. In September of 1991, the U.S. Nuclear Regulatory (USNRC) requested that the ASME O&M Committee consider revisions to the Code which would require that inservice pump and valve testing verify all safety functions, and be performed at or near design basis conditions.

A project has been started at TU Electric's Comanche Peak nuclear plant to develop technical information that can then help refine the Code requirements in a way that reduce the undue burden that might occur by testing components marginal to safety. ASME, the USNRC, the Electric Power Research Institute (EPRI), and the industry all recognize that overly restrictive requirements can unduly complicate plant operations, cause unwarranted system unavailability, and, most importantly, may reduce safety by degrading components through ineffective testing procedures and frequencies.

The typical IST program at a nuclear power plant today involves 30 pumps and 500 valves. The current cost of such a program varies considerably from plant to plant, but $500,000 per refueling cycle is about average. A main objective of the program described in this paper is to risk rank and categorize all the IST components at

a pilot facility, and attain exemption or relief on testing frequency for the components in the low risk category. A preliminary estimate is that it is possible to cut the current costs of the IST program by at least 50%, while maintaining or increasing overall plant safety.

RISK PERSPECTIVE

In a recent EPRI report (1993), a survey of eight nuclear plants showed that pumps and valves in their IST programs made up a relatively small percentage of total plant risk. For example, at the Surry unit, the contribution of all IST components contributed about 3% of total risk, as measured by core damage frequency (CDF). Similar results were obtained at the Peachbottom plant, where 6% of the risk came from IST components. PRA studies normally show that about 20% of any type of component represent 99.9% of the risk posed by those components as commonly estimated by core damage frequency or risk of offsite release of radioactivity. A good example of this statement is the motor operated valves (MOVs) studied[a] in conjunction with industry response to USNRC's Generic Letter 89-10. These two results suggest that of the 500 or so components in the typical utility's IST program, 80% of them taken all together will contribute less that 1 part in 10,000 to the total risk. Clearly, the resources being currently expended on IST programs are not commensurate with this new perception of risk. The work done with MOVs shows that (a) it is relatively easy to obtain a risk ranking of each component, (b) the ranking is quantitative, and (c) the final categorization into high-, medium-, and low-risk groups is relatively insensitive to the risk measure that is used. While there are still unresolved issues (such as truncation limits, "super-components," common cause failures, human event, and failure modes) associated with the use of PRA, these all can be handled in a way that allows an unambiguous ranking of IST components.

Moreover, the PRA is clearly a starting point, because the method for MOVs developed by EPRI and endorsed by industry specifically requires a "blended approach" for the final categorization of components. By this we mean that deterministic analyses, engineering judgment, and operational insights are added to the PRA results and can be used to explicitly consider factors not included in the PRA. It is often true that not all IST components are modeled in a PRA. For example, some important-to-safety components such as emergency diesel generator fuel oil transfer pumps are usually not modeled, but are implicitly included through initiating events or other means. The blended approach covers such circumstances. This defense-in-depth approach is consistent with the USNRC's Safety Goal Policy Statement (USNRC, 1986), and ensures a high degree of confidence in the PRA results.

RISK-BASED IST PILOT PLANT

The Comanche Peak pilot project is jointly sponsored by TU Electric and EPRI. Its objective is to ensure that both industry and TU Electric benefit from the project's outcome. Generic insights will be developed for use at other plants. The project will take advantage of IST work being jointly supported by the nuclear steam supply system (NSSS) owners groups, USNRC, Japan, and nuclear insurance companies, and will interface with the ASME research program. The project will also be coordinated with related Nuclear Energy Institute efforts, such as the Regulatory Threshold Working Group, and various owners' group activities, such as the Westinghouse Owners Group check valve program.

The intent of the pilot project at Comanche Peak is to develop a risk-based inservice approach consistent with other risk-based initiatives being pursued by industry. Related areas are inservice inspection (ISI); GL 89-10 MOV issues; Appendix B graded Q-list encompassing such issues as quality assurance, procurement, design verification, and commercial grade

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a. Electric Power Research Institute, *Application of PRA for the Development of the MOV Test Program described by Generic Letter 89-10*, Draft, April 1993.

replacement parts. It is also important to consider a new approach to re-engineering maintenance tasks being developed by EPRI, which integrates the Maintenance Rule, reliability centered maintenance, online maintenance, and related issues. While Comanche Peak will be the lead plant in the IST initiative, other plants will participate in the EPRI sponsored working group in order to make sure that a variety of plant types and vintages are covered. The mix of participants will ensure that the results have been widely tested, thus ensuring that they are industry generic.

A significant objective at Comanche Peak will be to determine what types of information will be necessary to support the ASME IST research effort and will be needed by the plant for an effective risk-based IST program. Compensatory measures will be examined to determine whether they will be required in some instances. The best way to accomplish this objective is to submit an actual code relief request to the USNRC based on the Comanche Peak (and other pilot plant) results, so that any real uncertainties (as opposed to hypothetical ones) can be resolved.

The project will develop generic processes to optimize IST. To do this, the project will examine testing frequencies (and other actions) needed to comply with USNRC and ASME requirements. The pilot project will address:

- Modified categorizations of component populations
- Modified testing frequencies
- Graded levels of testing
- Plant mode
- Testing effectiveness.

Results will be based on current technical requirements, current component populations, and their relative risk rankings. This project is not intended to remove components from the ASME IST Code requirements or USNRC oversight. Rather, it is intended to adopt a graded approach where the focus of testing and expenditures of resources are appropriately placed on the components that constitute the bulk of the risk.

APPROACH

To develop a generic approach, the project will use the Comanche Peak plant as prototypical of a Westinghouse four-loop plant, and then compare the results with other NSSS and architect-engineer combinations, plant generations, and identical units of a multiple unit plant. In order to assess how these factors impact ASME IST Code requirements, the Comanche Peak study will

- Apply risk-based technologies to IST components to determine their risk-significance
- Apply risk-based technologies to risk-significant components (identified in the IPE and outside ASME Code Class boundaries) to determine whether additional compensatory measures are appropriate
- Apply a combination of deterministic and risk-based methods to determine appropriate testing requirements or compensatory measures for IST components
- If feasible, determine if the IST testing methods and frequency intervals applied to the risk-significant components can be improved
- Submit code relief request(s) to the USNRC using project results
- Ensure that the results and insights from this project are available for use by the industry.

The Maintenance Rule Guidelines (NUMARC, 1993a) and MOV Guidelines (NUMARC, 1993b) will provide a starting point for establishing the risk-significance criteria. The results of the pilot plant efforts will then be provided to the ASME Risk-Based IST Research Task Force and the ASME O&M Committee to assist in the formulation of IST guidelines and IST requirements.

RANKING OF PUMPS AND VALVES

In addition to the Comanche Peak PRA, the risk-based approach being performed encompasses a review of critical safety functions and failure modes effects analysis for components in the IST program. The following sources provide useful data for monitoring component performance:

- Preventive maintenance program results
- Evaluations of industry-wide operating experience
- Generic common cause failure data.

The Comanche Peak pilot project will not only model the safety-related pumps and valves within the code class boundaries, as now specified by the 1989 edition of Section XI, but will also consider pumps and valves that are outside the code class boundaries, (e.g. emergency diesel generator fuel oil transfer pumps). A FMEA analysis is needed because components could be risk-significant for one failure mode and nonrisk-significant for others. Additionally, the analysis will also include pumps and valves that are functionally important in other modes of operation, such as shutdown. A breakdown of the Comanche Peak IST Pump and Valve Program is given in Table 1. The expected results of the IST pilot project is shown in Table 2.

CONCLUSIONS

A risk-based approach can improve IST programs now being implemented by operating nuclear power plants. Not only will safety be improved by focusing resources on risk significant components but significant cost savings can be realized in the following areas:

- Reduce testing for non-risk significant components
- Reduced number of engineering evaluations
- Reduced plant design modifications to test at or near design basis conditions
- Fewer new test procedures, and fewer tests during outages.

Table 1. Comanche Peak IST pump and valve program.

63 pumps in Units 1 and 2
1,252 valves in Units 1 and 2
Unit 1 is a mirror image of Unit 2
Some pumps and valves appear in systems common to both units

Table 2. Expected results of ranking IST components.

	Pumps (%)	Valves (%)
High	70	10
Medium	20	20
Low	10	70

Because risk-significant component reliability and availability will likely increase, it is therefore prudent for the industry to adopt a risk-based approach to IST in a timely manner.

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Risk-Based Ranking of IST Components at Seabrook Station

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ABSTRACT

Utilities that operate nuclear power plants are facing increasing cost-competitive pressures. In an effort to maintain, and in most cases improve, safety margins while reducing budgets, many companies are using probabilistic methods to help allocate resources efficiently. Probabilistic ranking methods and strategies are also receiving increasing acceptance from the U.S. Nuclear Regulatory Commission, The American Society of Mechanical Engineers, and other regulatory, standards, and oversight bodies. Application of probabilistic methods at Seabrook Station indicates that inservice testing (IST) has the potential for significant reductions in resource expenditures without compromising safety margins. This paper describes the preliminary results of a risk-based ranking of IST components at Seabrook Station and offers an overview of the strategy for applying these results to the IST program. The application will include additional ranking and sensitivity evaluations (beyond those described in this paper) to ensure the fidelity of the final conclusion.

INTRODUCTION

Seabrook Station is a four-loop Westinghouse pressurized water reactor. The Seabrook Station Probabilistic Safety Study (SSPSS) is a full-scope, Level III, living probabilistic risk analysis (PRA) and is updated for plant-specific data and modeling improvements on a refueling cycle basis. The risk model provides the capability to examine plant risk from a variety of perspectives. One of these perspectives is a ranked list of components based on their importance to risk (i.e., contribution to the core damage frequency or frequency of containment performance modes). Supplementary models can also be used to assess the importance of components to economic factors, such as forced outages, plant trips, and outage duration.

Component importance specifically includes consideration of multiple basic events (failure modes) where appropriate. Risk-based ranking of components and systems enables the company to focus and apply resources commensurate with the significance of the individual component. This approach results in increased understanding of the plant's level of safety, as well as efficient, prudent use of company and, ultimately, regulatory resources.

The inservice testing (IST) program (ASME, 1983) at Seabrook Station includes 462 components (27 pumps and 435 valves). Within the program, all of these components require essentially the same resource usage. A strategy to modify the IST program through application of a risk-based selection method has the potential to significantly reduce resource expenditures without compromising safety margins. In fact, a risk-based IST program offers the expectation of improved overall plant safety.

LIMITATIONS OF IMPORTANCE RESULTS

Risk-based importance ranking provides a useful way of prioritizing components based on the integrated risk model in the PRA. There are a number of potential uses for this ranked list; however, several points of caution are important for the user.

First, the rank should be used as a general indication of relative importance, not as an absolute numerical rank. Thus, the top components can be said to be more risk important than the lower components, but the absolute rank (1, 2, . . . 20) is less meaningful. Also, the importance measure cannot be used to say that one component is, for example, twice as important as another. Because of this, components are typically grouped into levels of importance, using the importance measure to determine the grouping. This interpretation compensates for uncertainties in data. It has not hindered insights, nor the use of ranking results.

Second, PRA system models, as detailed as they are, are limited in the extent to which they reflect actual plant conditions. Because Seabrook Station has just recently started commercial operation, the system models are quantified based on average data that, for example, consider motor-operated valves (MOVs) in all systems to have the same failure rate. If actual experience indicated differently (i.e., if a component is an outlier with respect to general component data), that may affect the component importance ranking. As an example, some MOVs that could experience high differential pressures during an accident have been demonstrated [prior to changes resulting from the U.S. Nuclear Regulatory Commission's (USNRC's) GL 89-10] to have failure rates that are one to two orders of magnitude higher than typical MOVs. The MOVs with higher failure rates may be ranked differently as a result of the higher failure rate.

Third, system models are analyzed with respect to severe accident risk (core damage and containment release) alone. Other functions, which may be important to economics or regulatory compliance, are not considered. PRA importance should be used along with other parameters of interest, including actual performance, to set overall plant priorities.

Finally, system and component importance calculations are inherently based on the way systems and components are modeled. Systems that were judged to be important to risk are modeled in detail; other systems are modeled only for specific components. For example, the reactor coolant system is modeled explicitly by the power operated relief valves and safety valves alone. The diesel generator is modeled as a single super-component, based on generic and plant-specific data. The performance of individual components (e.g., the pneumatic flow and temperature control valves) within this super-component are included implicitly. Some systems are entirely modeled implicitly, through initiating events (e.g., main feedwater). In all cases, systems are modeled to the level of detail for which data are available or needed to characterize risk.

SEABROOK RANKING METHODOLOGY

A number of probabilistic ranking methods are available to the industry. NUMARC 93-01 (1993) briefly describes measures known as risk reduction worth, core damage frequency contribution, and risk achievement worth. Another common measure, called Fussel-Vesely (FV) importance, is discussed in NUMARC 93-05 (1993b), and was used to rank the IST components at Seabrook Station. Fussel-Vesely importance is basically expressed as the fractional contribution of a system or component failure to the end state of interest (core damage, containment performance modes, capacity factor, etc.). While other importance measures are calculated by making bounding success or failure assumptions, FV importance has the advantage of using best-estimate values for system/component availability and reliability. FV importance also reflects the overall effects of existing design, procedures, and operational performance.

Seabrook Station does not rank based on raw importance values, but groups components having similar importance results. Table 1 displays the limits used to develop the risk significance groups.

Table 1. Risk significance group limits.

Risk significance	Fussel-Vesely importance
HI	FV > 0.01
MED	FV > 0.001
LO	FV > 0.0001
NONE	FV < 0.0001

RESULTS

The IST program at Seabrook Station includes 462 components, 193 of which are modeled in the PRA. The remaining 269 IST components are not modeled because they would not be needed to mitigate an accident, nor would they be included in an initiating event. However, as can be seen in Table 2, only a minority of these components individually have any noticeable contribution to plant risk for reasonable changes in their failure rates. An even smaller minority could be considered appreciable contributors (e.g., HI and MED).

Seabrook Station's current annual core damage frequency (CDF) is 8×10^{-5}. Using the 0.001 threshold for medium risk significance yields approximately a 8×10^{-8} cutset frequency. A cutset is defined as the combination of failures necessary to create core damage. Because total CDF uncertainty typically spans an order of magnitude, the lower threshold for the medium risk category is still below the 10^{-6} frequency that is used as a cutoff in ANSI/ANS 51.1 (ANSI/ANS, 1983). Section 3.2.3 discusses using a probabilistic approach to determine the events that need to be considered for design basis. While application of this section to IST may be considered a broad interpretation, a graded approach to surveillance and testing, consistent with component and/or system importance to safety is receiving increased attention by both the industry and the USNRC.

Table 2. Summary of IST component importance ranking.

Risk significance	Number of components
HI	17
MED	43
LO	49
NONE	353

STRATEGY

When proposing changes to the IST program, we must carefully consider the overall change in plant risk. In this regard, we must be cautious with respect to component groups versus individual components when using ranking results. Seabrook Station's strategy will therefore include a combination of risk ranking, sensitivity evaluations of various component groups, reliability considerations (e.g., periodic stroking to ensure component function), and measures beyond safety risk. The specific approach will also build on our successful implementation of GL 89-10.

CONCLUSION

Because most IST program components have little risk significance, reductions in test scope, and frequency, or both for these components should be acceptable. For example, typical valve failure rates are 10^{-2} to 10^{-4} per demand, and many IST valves see no more than one to two demands per quarterly test interval. One therefore expects to see much less than one failure per test interval. Because many of these valves get a demand only during testing, the interval could be extended to 18 months without a significant change in failure probability. Alternatively, the valves that are not risk-significant could be removed from the IST program and be maintained and tested as appropriate under the Maintenance Rule (10 CFR 60.65). Components with HI or MED risk significance would then be subject to more effective surveillance testing and performance monitoring strategies.

IST program modifications of this type are currently being explored by the ASME Research Task Force on Risk Based Inservice Testing. Decreasing the size of the IST program would allow resources to be better applied to those components and systems most important to safe operation of the power plant.

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Risk-Based Maintenance Method and Applications

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ABSTRACT

Effective maintenance programs can play a significant role in minimizing equipment and structural failures. All aspects of maintenance (i.e., scope, method, timing, and acceptance criteria) can significantly affect the likelihood of component failures. For many pressure-boundary components or others that are subjected to various service conditions in the nuclear power, as well as other industries, inservice maintenance requirements are either based upon prior experience and engineering judgment or are nonexistent. At best, some include an implicit consideration of risk (probability of failure times consequence).

To guide the development of an effective maintenance program that focuses on critical plant equipment with the right frequencies and techniques, a risk-based method to maintenance planning has been developed. The method uses results of probabilistic risk assessment, related studies, and relevant industry experience to provide guidance for managing the risks associated with system, structure, and component (SSC) failures. This paper provides suggestions that may be considered during the development of maintenance practices/policies intended to focus on the management of risk associated with SSC failures. The benefits of incorporating these suggestions are also discussed.

BACKGROUND

Maintenance is the primary means of mitigating and managing the effects of component degradation at nuclear facilities. Maintenance directly affects the safety of nuclear power plants. Several recent plant events have shown that improper maintenance or a lack of maintenance can contribute significantly to plant incidents (e.g., transients at Rancho Seco and Davis Besse, and the Salem anticipated transient without scram events). In these and other events, safety-related plant equipment functions have been impaired by poor maintenance practices or a lack of maintenance on the specific equipment or on ancillary equipment that affects the ability of the safety-related equipment to function. In some cases, time-related degradation of equipment that has not been detected, corrected, or managed by the maintenance program has been a significant contributory factor to equipment failure.

For many pressure-boundary components or others that are subjected to various service conditions in the nuclear power, fossil fired-power and chemical processing industries as well as others, inservice maintenance and inspection requirements are either based upon prior experience and engineering judgment or are nonexistent. At best, some include an implicit consideration of risk (probability of failure times consequence).

Since the early 1980s, a number of research programs sponsored by various Federal Government agencies have been developed for addressing the general question of how to formally incorporate risk considerations into plans and/or requirements for the inservice inspection and maintenance of components and structural systems at nuclear power plants (ASME, 1991 and 1992; USNRC, 1989, to name a few). Generally, the overall recommended approaches for developing these plans are through the use of

probabilistic risk assessment (PRA) results and plant relevant information.

PRA technology, used extensively in the nuclear industry following the Reactor Safety Study (WASH-1400) (USNRC, 1975), has been successfully applied in several other industries [see the November 1984 issue of *Mechanical Engineering* (Moghissi, 1984)].

This paper describes some of the methods and results directly applicable to risk-based maintenance. Approaches are provided that may be considered during the development of maintenance practices, intended for managing of the risk associated with system, structure, and component (SSC) failures. The approaches can be applied to (a) assess the impact on plant risk from failures of critical SSCs, (b) develop a risk-based graded method to testing and maintenance, and (c) develop a comprehensive maintenance program to manage the risk associated with failures of safety-significant SSCs. This approach can also be applied to inservice testing and inservice inspection, since testing or inspection is a specialized subset of maintenance.

OVERALL METHODOLOGY

Figure 1 shows the technical method and information that is needed for the development of a risk-based maintenance program (Vo, 1994). Descriptions of the method are provided in the following paragraphs. To effectively develop a maintenance program, sensitivity analyses need to be performed throughout the overall process.

This method has similarities to the approach adopted by industry in responding to the maintenance rule (NUMARC, 1993a) and NUMARC maintenance guideline (NUMARC, 1993b).

System Definition

The development of the maintenance program begins by defining the systems, structures, and components and their boundaries and success criteria. For nuclear power plants, this part of the process is already well defined. Information related to SSCs that are being considered for maintenance is also assembled in this step.

SSC Identification and Prioritization

A risk-based graded approach to maintenance involves selective and judicious assignment of resources to maintain facilities and equipment based on site-specific risk quantification. Thus, it is essential that a site-specific maintenance plan ensures that the risk associated with safety significant SSCs be included in this risk quantification.

For nuclear applications, techniques normally employed in formulating an approach to maintenance for a specific facility are the PRAs described in NUREG/CR-2300 (ANS and IEEE, 1983). PRA is a systematic method that identifies and delineates the combinations of events that, if they occur, will lead to a severe accident (core damage) and/or other undesired events. The method is used to estimate the frequency of occurrence for each combination and to estimate the consequences.

PRA results are plant-specific. The key advantage of using PRA information is that its results can be used to allocate resources to develop an effective maintenance program. PRA results can also be used to support the ongoing prioritization of potential safety issues and related research. This includes a means for investigating where safety improvements might best be pursued, the cost-effectiveness of possible plant modifications, the importance of generic safety issues, and the sensitivity of risks to issues as they arise.

Using the PRA results, the most risk important SSCs can be identified and prioritized. There are a number of importance measures that can be used to achieve this purpose. Vo et al. (1989a), Vo et al. (1993), and Taylor et al. (1986) provide applications of importance measures in identifying and prioritizing nuclear systems and components for maintenance as well as inspection. In these references, the authors describe the techniques and their applications through the use of PRA information to assist the inspector in identifying risk important systems, components,

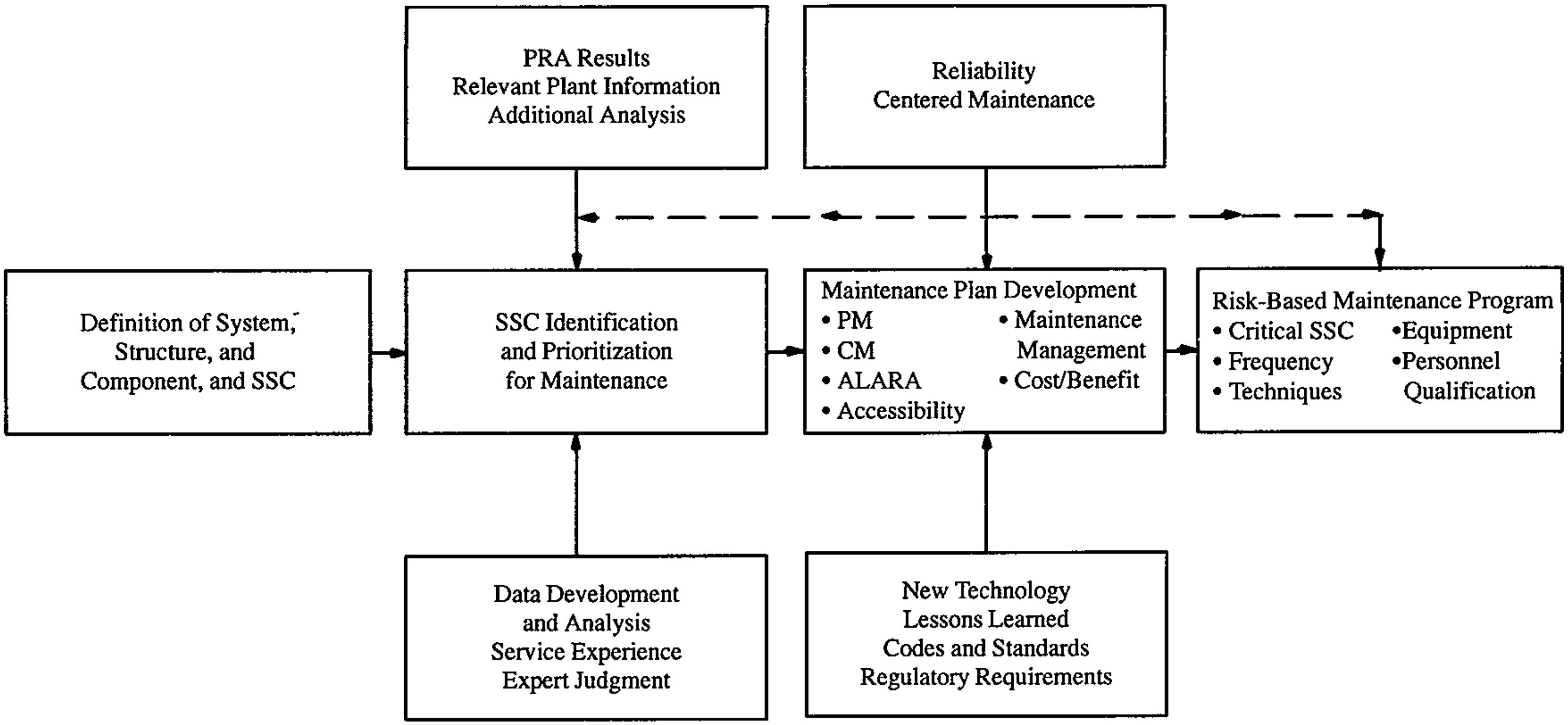

Figure 1. Technical methods and information for developing a risk-based maintenance program.

maintenance activities, and procedures. Vo et al. (1990) also provide a comprehensive technique for identifying generic system importance for light water reactors. Detailed results of the risk important systems for pressurized water reactors and boiling water reactors are provided in this reference. Vesely et al. (1983) discuss the approach of including the system and component aging in the prioritization process. The ASME has published *Risk-Based Inservice Inspection Guidelines for Nuclear Power Plants* (ASME, 1992). The procedures provided in this document may be used for prioritizing and identifying critical SSCs.

Like other safety analyses techniques, the PRA approach to prioritization of safety-significant SSCs has limitations. These limitations can relate to the quantitative measurement of certain types of human actions (e.g., errors of commission), high failure rate of equipment resulting from common-cause effects such as aging, and an incomplete understanding of the physical progression and consequences of core damage accidents.

For those plants that have existing Reliability Centered Maintenance (RCM) programs, these are other resources for identifying and prioritizing the critical systems, structures, and components. The RCM concepts will be further discussed in the next subsection. In addition, information from other techniques such as Hazard Operability (HAZOP) studies (Lees, 1980) can also be used as part of the safety and risk evaluation process. The HAZOP technique has been applied to several nuclear facilities owned by the U.S. Department of Energy (DOE). Generally, the HAZOP technique uses the same concept as the FMEA. Results from HAZOP analysis can be used to identify the critical SSCs. HAZOP, however, does not address aging degradation specifically.

Maintenance Plan Development

Generally, an effective maintenance plan should include the following key elements: (a) the preventive maintenance, predictive maintenance, and corrective maintenance (PM/CM) plans for critical SSCs, (b) equipment accessibility, (c) as low as reasonable achievable (ALARA) radiation exposure considerations, and (d) maintenance management and cost/benefit analysis.

The maintenance plan development should focus on critical SSCs, as identified from the previous step (Figure 1). The PM/CM plans should be developed for each of the critical SSCs, depending on their criticalities. For example, effort should be focused on the most important components within the plant. Given critical SSCs, existing approaches may be used to determine the PM/CM plans for each component. For predictive maintenance, plans may include oil analysis, vibration monitoring, MCE, MCSA, and thermography. McCormick (1981) and Lewis et al. (1987) discuss the development of the PM/CM for components. Enderlin and Vo (1992) describe how to develop maintenance plans for SSCs including plant equipment aging. In this reference, the authors describe a comprehensive approach using PRA results and RCM technique in combination with plant-relevant information, including lessons learned from other industries (e.g., the commercial airline industry, U.S. Air Force, U.S. Navy Ballistic Submarine, and the Japanese nuclear power industry) for developing effective maintenance plans to manage the risk associated with failures of nuclear power plant components. Valuable lessons learned identified from this work include (a) increasing the use of standardization throughout the nuclear industry, (b) developing accurate long-range forecasting techniques for determining spares requirements, (c) using multiyear procurement in spares acquisition, and (d) maintaining sufficient flexibility in design and performance specifications to permit parts substitutions.

Some of the most important elements of the maintenance plan are ALARA considerations. A maintenance plan should center on minimizing radiation exposure to the workers, particularly for nuclear facilities. The ALARA considerations should be incorporated into the development, and recommended ALARA considerations from the USNRC should be exercised. Permanently installed shield walls, portable shielding, and

decontamination facilities should be located to reduce radiation fields consistent with ALARA guidelines. Components and systems should incorporate valves to allow for decontamination and flushing before maintenance or removal.

The developed plan should also address the accessibility for performing the maintenance. Access should be provided to equipment used for performing maintenance and equipment to be maintained. Each system should be designed to allow for maintenance of its components. Large components should be located in an area that allows overhead lifting, removal to a shop location, or complete disassembly during the life of the facility and component. System components that require local reading or calibration should be situated for easy access by operating and maintenance personnel.

Maintenance management perspective as well as cost/benefit analysis may be used to determine which of the PM/CM plans are most economically beneficial without compromising the plant risk. Heaberlin et al. (1983) provides a good description for performing a risk/cost benefit study. Vo et al. (1991) discusses in detail risk and cost analyses for modifying system components for nuclear power plants.

It is also useful to review the lessons learned by others who have been confronted with similar issues. Where appropriate, these lessons learned can be used for developing maintenance plans. For instance, information related to RCM or new technology may be incorporated into the development of the maintenance plan.

Reliability-centered maintenance was developed within the context of the aerospace industry. The success of RCM programs in the commercial airline industry, as well as in the U.S. Air Force and the U.S. Navy, encouraged the Electric Power Research Institute (EPRI) to investigate the feasibility of applying the concepts of RCM to commercial nuclear power plants. Because of the favorable results produced by the EPRI investigation and the work of the EPRI RCM User Group, many U.S. nuclear plants are currently developing and applying RCM (80 to 100 plants). The general objectives of the RCM programs currently employed by U.S. nuclear power plants have been to document the basis for plant preventive maintenance programs, optimize the maintenance and plant resources, and increase plant safety, reliability, and availability. Detailed discussions of EPRI's approach and the development of the RCM are summarized in *The Energy Daily* (1992). During the last 5 years, EPRI has tested the RCM program at Rochester Gas & Electric's Ginna Plant and Southern California Edison's San Onofre Plant, Units 1 and 2. Chockie et al. (1991) discusses RCM lessons learned from the nuclear power industry.

Codes, standards, and regulatory requirements should be included in the maintenance plan development. For nuclear power plants, the recommended testing and maintenance practices for important components are provided in the ASME OM standards and guides. For critical components, inservice testing requirements are provided in the ASME OM Code. Comprehensive considerations of the activities and functions, as required in 10 CFR 50, should be included in the development. References, standards of guidelines, such as those developed by The American Nuclear Society, American Society of Mechanical Engineers, Institute of Electrical and Electronics Engineers, American Society for Testing Materials, or EPRI, should be used to provide specific programmatic requirements or guidance for maintenance of specific types of equipment.

Risk-Based Maintenance Program

One the important aspects of maintenance is to have a program that provides effective maintenance for the right components with the proper frequency and techniques. Maintenance program activities should be focused on critical SSCs, as identified from the previous step.

Depending upon component criticalities, the recommended maintenance frequencies on components (e.g., by manufacturers) may need to be reanalyzed to adjust the plant risk to a minimum level. Technical analyses, including testing and

maintenance effectiveness, should be performed to set the required frequencies for performing maintenance of critical SSCs. Lewis et al. (1987) discusses the evaluation of maintenance frequencies, including component replacement policy and age replacement on the maintained safety system components. This technique may be used along with plant-specific information to determine the maintenance frequencies for specific critical SSCs. Information regarding existing RCM programs in the nuclear industry may be used to evaluate the required maintenance frequencies.

Regarding maintenance equipment and techniques, advanced equipment and techniques should be used when performing maintenance. The program should allow for adopting new innovative technologies as they are validated. For personnel qualification, EPRI has published *Guidebook for Maintenance Proficiency Testing*, EPRI NP-6679. This guide is designed as a workbook for developing proficiency tests for maintenance personnel in nuclear power plants. The tests can document the competence of personnel on plant-specific maintenance tasks, allowing qualification without additional training for experienced hires, contract workers, and experienced employees needing refresher training (EPRI, 1989).

EPRI has also published a handbook on RCM concepts to guide the nuclear utilities in performing their maintenance. With RCM, the idea is to inspect, test, and repair systems and components only when they experience or show evidence indicating that they will soon fail (*The Energy Daily*, 1992). This handbook may also be used to develop maintenance frequency and techniques for critical components or structures.

The maintenance program should define the methods and techniques to be used for each system component of the facility. The program should be based on a balanced combination of preventive, corrective, and predictive maintenance in combination with inservice inspection and testing. The program should cover equipment from the time it is installed until it is removed from the plant for disposal.

RISK-BASED APPLICATIONS FOR MAINTENANCE

The applications of the approaches discussed in the preceding section are provided in this section. The discussions are centered on nuclear applications. Following are recommendations that may be used in developing risk-based maintenance programs, including inservice testing. The discussions below closely follow the steps identified in Figure 1.

Following the definition of SSCs, the next step in the evaluation is to identify and prioritize SSCs for maintenance. For maintenance, importance measures involving small changes in risk may be of interest because the purpose of maintenance is to prevent large changes in risk. Tables 1 and 2 show examples of system and component rankings for typical PWR and BWR systems (Vo et al., 1992; Enderlin and Vo, 1992). The order of system and component rankings in the tables was determined by the Fussell-Vesely Importance Measure, which is defined as the fraction of the total risk (core damage) that results from failures involving the system or component of interest. The failure modes associated with component failures are also included in the Table 2.

Results similar to those shown in Table 1 may be found in most recently developed PRAs. For PRAs where this information is not included, the approach summarized in the preceding section is recommended for use. Where important systems are reported in PRAs, the important components and structures can be identified by a number of techniques, such as fault tree analysis and failure modes and effects analysis (FMEA). Vo et al. (1989a) provides a comprehensive discussion on component identification and selection. McCormick (1981) provides a brief overview of some of the more widely used computer programs currently available for event tree and fault tree analyses. Additional computer software is referenced in ASME (1991).

Table 1. Fussell-Vesely system importance for typical LWR systems.[a]

Fussell-Vesely ranking	PWR system	BWR system
High	DC power	DC power
	High-pressure injection	Reactor pressure vessel[b]
	Low-pressure injection	Emergency service water
	Service water	High pressure injection
Medium	Reactor pressure vessel[b]	—
	Reactor protection	Reactor core isolation cooling
	Auxiliary feedwater	Standby liquid control
	AC power	AC power
Low	Safety relief valve	Power conversion[c]
	Power conversion[c]	—

a. Obtained from Vo et al., 1989b.

b. Prioritized from separate study.

c. Includes the main steam, main feedwater, and condensate systems.

Table 2. Component importance for a typical PWR auxiliary feedwater system and a typical BWR emergency service water system.

Ranking	Component	Failure mode
PWR auxiliary feedwater		
1	Pump suction valves (control, motor-operated valves, etc.)	Failure to operate
2	Pump discharge valves (check, control, motor operated valves, etc.)	Failure to open/close
3	Turbine-driven pump	Failure to start and run
4	Motor-driven pump	Failure to start and run
5	Instrumentation/control	Loss of function
BWR emergency service water		
1	Pump discharge valves (MOVs, CVs)	Failure to open
2	Heat exchanger discharge valves (MOVs, manual values)	Failure to open
3	Motor-driven pump	Failure to start and run
4	Instrumentation/control	Loss of function
5	Heat exchanger inlet valves (manual valves)	Fail to remain open

It is also recognized that some safety-significant SSCs may not be addressed in PRAs because they exhibited a low failure frequency in the years preceding the PRA, which constitute the early part of the useful period of the SSCs under consideration. In this case, the detailed results of PRAs, supplemented by plant-specific information, are required for analysis. In some cases, reconstruction of event trees or fault trees are recommended.

After the SSCs have been identified and prioritized, detailed maintenance plans must be developed for all SSCs. The plans should be based on a balanced combination of preventive, corrective, and predictive maintenance in combination with inservice inspection and testing. Table 3 shows an example of the current testing requirements for typical PWR auxiliary feedwater system components. Table 4 shows an example of the current testing requirements for typical BWR emergency service water system components. This information was derived from the current ASME O&M Code requirements (ASME, 1990), and by discussions with the expert in pump and valve testing. Maintenance activities should be planned along with test activities to minimize plant downtime.

Component-specific failure information, lessons learned, generic component failure history, and cost/benefit analysis may be incorporated into the development. The ASME Inspection Guidelines (ASME, 1992) provide a database related to structural failures that may be useful for the development of maintenance programs.

Table 3. Example of testing requirements for typical PWR auxiliary feedwater system components.

Component	Frequency	Technique
Pump Suction Valves		
Motor-operated valves	Quarterly, refueling, shutdown	Exercise test Stroke time Valve position indicator Obturator test Operator movement indicator
Pneumatic-operated valves	Quarterly, refueling, shutdown	Same as the above plus fail-safe testing
Pump Discharge Valves		
Check valve	Quarterly	Full stroke testing exercise, open and close verification
Pneumatic control valve	Quarterly	Same as pump suction valves
Motor-operated valve	Quarterly	Same as pump suction valves
Turbine-Driven Pump	Quarterly	Set speed, measure vibrational test, differential pressure and flow rate
Motor-Driven Pump	Quarterly	Same as the above plus measure speed
Instrumentation/Control	Quarterly	Instrument accuracy

Table 4. Example of testing requirements for typical BWR emergency service water system components.

Component	Frequency	Failure/techniques
Pump Discharges		
Motor Operated Valves	Quarterly	Exercise test, stroke time, valve position indicator verification (2 year), obturator movement verification
Check Valves	Quarterly	Full-stroke testing exercise open, closure verification
Heat Exchanger Discharge Valves		
Motor-operated valves	Quarterly	Same as pump discharge MOV
Manual valves		Passive component, Category B, normally open, no testing
Motor-Driven Pump	Quarterly	Record speed, measure bearing vibration, differential pressure, and flow rate
Instrumentation/Control	Quarterly	Instrument accuracy
Heat exchanger Inlet Valves		
Manual valves	Quarterly	Same as heat exchanger discharge manual valves

The final risk-based maintenance program should specify the SSCs to be maintained, the maintenance frequency, the procedures and techniques, and personnel qualification. During maintenance, critical components undergo manufacturer's recommended periodic testing and surveillance. The components are replaced in a specified time before they lead to failure. The effect of maintenance on component failures may be included by reducing component failures by a "maintenance effectiveness factor." On the basis of this reduction in failure probability, a suitable maintenance frequency may be determined to keep the component failure probability below target levels during their life. Research in this direction is in progress, and results can be expected soon. EPRI has published a handbook to guide nuclear utilities to use the RCM technology to keep plant components and systems operating reliably (*The Energy Daily*, 1992). This information may be used in determining the maintenance and testing frequencies, equipment, and techniques for SSCs.

SUMMARY AND CONCLUSIONS

In summary, the risk-based graded approach to maintenance presented in this paper should prove to be a useful tool for planning testing and maintenance activities at nuclear power plants and other facilities. The approach recommended uses PRA results, RCM techniques, or both in combination with plant-specific information and relevant industry experience to provide guidance for developing testing and maintenance practices. Once the high-risk systems and components have been identified, effective maintenance and testing programs can be developed (method, frequency, and extent) to manage risk associated with system, component, and structure failures. There are

potential situations where high-risk importance areas and current practices may not adequately control plant risk because of component failures, thus requiring additional measures to minimize the potential impact of component degradation. Improvements may be required in optimizing maintenance or overhaul frequencies, selecting maintenance methods, or selecting replacement components or modifications to component design requirements.

The recommendations in this paper could also be useful in establishing overhaul frequency, developing outage plans, and establishing control procedures. These recommendations could also be useful in selecting the proper balance among maintenance methods (e.g., preventive maintenance versus corrective maintenance), selecting replacement components, especially where a diminishing manufacturing source is an issue, and establishing design modifications to ensure adequate maintainability with respect to aging issues. Moreover, the approach set forth has the potential to enhance aging management by providing suggestions that focus maintenance on risk-significant SSCs. Research in maintenance frequencies for the SSCs is currently underway in various industries. When available, the data will be used to develop improved maintenance plans for critical SSCs.

Improved performance of plant testing and maintenance has been increasingly emphasized by the nuclear and other industries. As a result of insights from PRA and recognition that many significant plant event precursors continue to occur, the USNRC is reassessing whether some current practices and initiatives are in the best interest of plant safety. An example of an important issue that has been a concern to the USNRC is maintenance and testing during shutdown. Applying a risk-based maintenance approach may provide valuable insight regarding outage planning and control.

The most significant benefits that can be derived from the technology presented in this paper provide a framework for allocating maintenance resources in a cost-effective manner, which helps to focus maintenance where it is most needed.

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Safety Significance of Inadvertent Operation of Motor-Operated Valves in Nuclear Power Plants[a]

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ABSTRACT

Concerns about the consequences of valve mispositioning were brought to the forefront following an event at Davis Besse in 1985. The concern related to the ability to reposition "position-changeable" motor-operated valves (MOVs) from the control room in the event of their inadvertent operation and was documented in U.S. Nuclear Regulatory Commission (USNRC) Bulletin 85-03 and Generic Letter (GL) 89-10. The mispositioned MOVs may not be able to be returned to their required position due to high differential pressure or high flow conditions across the valves. The inability to reposition such valves may have significant safety consequences, as in the Davis Besse event. However, full consideration of such mispositioning in safety analyses and in MOV test programs can be labor intensive and expensive.

Industry raised concerns that consideration of position-changeable valves under GL 89-10 would not decrease the probability of core damage to an extent that would justify licensee costs. As a response, Brookhaven National Laboratory has conducted separate scoping studies for both boiling water reactors (BWRs) and pressurized water reactors (PWRs) using probabilistic risk assessment (PRA) techniques to determine if such valve mispositioning by itself is significant to safety. The approach used internal events PRA models to survey the order of magnitude of the risk-significance of valve mispositioning by considering the failure of selected position-changeable MOVs. The change in core damage frequency was determined for each valve considered, and the results were presented as a risk increase ratio for each of four assumed MOV failure rates. The risk increase ratios resulting from this failure rate sensitivity study can be used as a basis for a determination of the risk-significance of the MOV mispositioning issue for BWRs and PWRs.

INTRODUCTION

During the Davis Besse event in 1985 (USNRC, 1985a), multiple motor-operated valves (MOVs) were mispositioned by the control room operators, and then could not be returned to their correct position due to incorrect torque switch settings that prevented them from operating under the existing high differential pressure (dP) conditions. After the Davis Besse event, the U.S. Nuclear Regulatory Commission (USNRC) staff issued Bulletin 85-03 (USNRC, 1985b), which recommended that licensees establish programs to ensure that MOV switch settings for several high-pressure safety-related systems were selected, set, and maintained correctly to accommodate the expected maximum differential pressures during both normal and abnormal events within the plant's design basis. The bulletin also indicated that inadvertent equipment operations (such as valve closures or

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a. Work done under the auspices of the U.S. Nuclear Regulatory Commission.

openings) that are within the plant design basis should be assumed when determining maximum dPs. Supplement 1 (USNRC, 1988) to Bulletin 85-03 clarified which valves were to be included when verifying the ability to recover from mispositioning and defined inadvertent equipment operations, as discussed above.

After evaluating the responses to Bulletin 85-03 and performing a Regulatory Analysis, the USNRC staff issued Generic Letter (GL) 89-10 (USNRC, 1989), which extended the recommendations of Bulletin 85-03 and its supplement to "all safety-related MOVs as well as all position-changeable MOVs." Supplement 1 (USNRC, 1990a) to GL 89-10 limited the scope to all MOVs that are both in safety-related piping systems and that can be mispositioned by operators from the control room.

The Regulatory Analysis for Generic Letter 89-10 included a value-impact analysis of the proposed expansion of the scope of Bulletin 85-03 to all safety-related systems, as presented in NUREG/CR-5140 (Higgins et al., 1988). Because Bulletin 85-03 already included the valve mispositioning issue, the value-impact analysis did not separately consider the value-impact justification of the inclusion of position-changeable valves. Further, current probabilistic risk assessments (PRAs) rarely include errors of commission during an accident sequence, such as the inadvertent mispositioning of a valve. Therefore, a comprehensive quantitative evaluation of the effect on core damage frequency (CDF)[b] resulting from the inclusion of position-changeable valves would require substantial remodeling of the PRA and was not performed in NUREG/CR-5140. However, it was qualitatively concluded that the inclusion of valve mispositioning in the analysis would enhance the benefit (value) obtained for the expansion of Bulletin 85-03 to all safety-related MOVs.

b. Some PRAs use core melt frequency instead of CDF. For consistency, this paper uses the term CDF to represent risk.

The Boiling Water Reactor Owner's Group (BWROG) agreed to address mispositioning of nine MOVs under Bulletin 85-03, but subsequently Beck (1990) and Beck (1991) argued that valve mispositioning need not be considered in the licensees' responses to GL 89-10. The Westinghouse Owner's Group (WOG) has taken a position (Eliasz, 1992) concerning position-changeable valves in PWRs consistent with that taken by the BWROG. Among the owners groups' arguments is the statement that the PRA analysis in NUREG/CR-5140 does not clearly indicate that consideration of additional position-changeable valves under GL 89-10 would decrease the probability of core damage to an extent that would justify the additional licensee costs. As discussed earlier, the analysis in NUREG/CR-5140 was performed to extend Bulletin 85-03, which already considered position-changeable valves, to all safety-related systems. Therefore, that analysis did not separately justify the consideration of valve mispositioning.

As a result, Brookhaven National Laboratory (BNL) conducted two separate scoping studies (Ruger et al., 1991 and 1993) using PRA techniques to determine if valve mispositioning (considered by itself) is significant to safety in boiling water reactors (BWRs) and pressurized water reactors (PWRs). Based on the sensitivity analysis in the BWR study, the USNRC accepted (Murley, 1992) the BWROG argument that the licensees for BWRs need not include consideration of valve mispositioning from the control room in their programs for GL 89-10. The modified USNRC staff position for BWRs is formally presented in Supplement 4 (USNRC, 1992) to GL 89-10. The USNRC staff is currently using the PWR study to determine a position concerning valve mispositioning in PWRs.

The remainder of this paper discusses the methodology used in the BNL studies and a summary of the results obtained.

ANALYSIS METHODOLOGY

Objective and Scope

The objective of these scoping studies was to use PRA techniques to determine if valve mispositioning is a safety-significant issue. It was clear from the outset that a comprehensive evaluation of all mispositionable MOVs would not be possible using existing PRAs. Current PRAs rarely include errors of commission during an accident sequence, such as inadvertent mispositioning of valves. This is due to the difficulty in modeling such errors, which have an extremely large number of possibilities. However, within program constraints, the risk-significance of the more important, active and passive, position-changeable MOVs was estimated.

The "position-changeable" valves under consideration include all MOVs in safety-related systems that are not prevented from inadvertent operation from the main control room (i.e., by keylock switch or breaker racked out). These MOVs may be considered as active or passive. Consistent with the American Society of Mechanical Engineers (ASME) Code, Section XI definitions, active valves are considered to be valves that are required to change position in order to perform a specific function in shutting down the reactor to a cold shutdown condition or in mitigating the consequences of an accident. Passive valves are not required to change position to accomplish these specific functions. Passive valves are generally test or maintenance valves. In this work, active valves include any MOVs that receive an automatic actuation signal or that may require remote manual operation during postulated scenarios. Mispositioning of valves with either active or passive safety functions is of concern. Mispositioning can occur prior to an event (e.g., test valve left open after completing a test) or during the course of an event.

Mispositioning of passive valves was clearly part of the original concern, and these valves certainly warrant consideration. However, valves that perform an active safety function are also capable of being mispositioned. After an active valve performs its required function during an event, either by manual or automatic activation, the potential exists for a subsequent mispositioning (either inadvertently or intentionally due to misdiagnosis) by the operator, back to its original position. Also note that many mitigation systems are in a standby mode during normal operation, with relatively low dP and flow conditions. Sometime later during an event, after initial valve actuation, higher dP or flow conditions may develop that could prevent recovery from a subsequent mispositioning, even though the valve initially actuated from its standby condition. In analyzing their MOVs under GL 89-10, licensees may not have considered such mispositioning of active valves, and hence, may not have addressed the worst case dP and flow conditions.

Some utilities have used the practice of blocking a passive valve from inadvertent operation to prevent its mispositioning. Blocking can be done by several means such as keylock switches, physically locking the valve, and racking out the circuit breaker to the motor operator. However, because the location of blocked valves is very plant-specific and their identification is difficult, valves prevented from inadvertent operation from the control room, at some plants, were still included in the present analysis. Therefore, all active and passive MOVs that could be identified as capable of degrading safety systems by the process outlined above were evaluated for their risk-significance.

Valves that are considered "passive" are candidates for blocking because they will not have to automatically change position on automatic system operation. A utility may choose to block a passive valve in order to avoid the need for a GL 89-10 analysis. However, the blocking of even passive MOVs can cause concerns because it limits the flexibility that operators have in reconfiguring the system in response to ongoing events and component or system level failures. Therefore, blocking should be approached with

caution, and each case should be carefully evaluated.

PRA Models

The approach uses an internal events PRA model to determine the change in CDF of selected position-changeable MOVs. The first step identifies all active and passive position-changeable valves in the PRA. They are then failed (failure rate increased to 1.0 failures per demand) one at a time. The resulting change in CDF is then calculated, with the nonfailed MOV failure rates remaining at their standard, base case, PRA values (usually 10^{-5} to 10^{-3} failures per demand). This calculation initially assumes that the probability of both inadvertent operation and the inability to subsequently reposition (due to high dP or flow) is a certainty (probability = 1.0). Valves that are not risk-significant can then be screened out. For those valves, where this first step results in a notable (>2X) change in CDF, a parametric sensitivity study is used to estimate the effects of the probabilities of both mispositioning (e.g., due to operator error) and the failure to correctly reposition due to differential pressure and flow conditions.

Two BWR and two PWR plant PRA models were selected for the studies in order to include as wide a range of dominant accident sequences and plant systems as practical. Two criteria affected the selection process: (a) the availability of PRA models on the Integrated Reliability and Risk Analysis System (IRRAS) (Russel et al., 1991) and the System Analysis and Risk Assessment System (SARA)[c] and (b) the inclusion of different nuclear steam supply system vendors. IRRAS/SARA contains PRA data for the dominant accident sequences for the NUREG-1150 (USNRC, 1990b) power plants. Three NUREG-1150 plants were used for these studies: Peach Bottom (BWR), Grand Gulf (BWR), and Surry 1 (Westinghouse PWR). Oconee 3 (B&W PWR) was selected as the fourth IRRAS/SARA model, even though it is not a NUREG-1150 model, because it was the only B&W plant available. Use of these four IRRAS/SARA models should provide a reasonable sampling of risk-significant MOVs in both BWRs and PWRs. This approach should therefore identify the most risk-significant valves. However, this position-changeable valve identification process will not be exhaustive, as described below.

First, certain passive MOVs may not be modeled, even in the full PRA, because they were not perceived to have a risk-significant safety function, (e.g., motor-operated drain valves). Secondly, since the IRRAS/SARA model contains only the dominant accident sequences for each plant, both active and passive MOVs in the remaining nondominant sequences will not appear. Before truncation, these nondominant sequences were quantified using standard PRA MOV failure rates (approximately 10^{-5} to 10^{-3} failures per demand.) These sequences were not risk-significant with these standard MOV failure rates, but could possibly be more significant if the higher valve failure rates appropriate to the mispositioning issue were used. For the same reason, certain MOVs in the dominant sequences are also not included. These are valves that are in cutsets that were truncated from the sequence when the standard failure rates were used. Again, use of larger failure rates would make these cutsets more significant. Finally, because the dominant accident sequences and system designs are plant specific, consideration of selected plants also limits the systems and valves considered.

There is some concern that the base-case PRA MOV failure rates should actually be considerably above base-case values to account for poor MOV operation under high dP or high flow conditions, as discovered during GL 89-10 testing. The current base-case failure rates were derived from experience obtained from stroke testing and operation of MOVs generally, without high dP or flow across them. To be consistent with existing PRAs, standard MOV failure rates were used as a base case in this analysis. It should be noted that the occurrence of scenarios resulting in the maximum design dP or flow at a particular

c. IRRAS 2.5 and SARA 4.0 were used for this analysis. Use of SARA is equivalent to the use of the sequence/cutset analysis portion of IRRAS.

valve, when it is called upon to operate, is somewhat unlikely. Further, the use of lower base case failure rates typically results in a larger risk increase upon failure. Thus, such an assumption should be conservative.

MOV Identification

Several steps were taken to include as many position-changeable MOVs in these scoping studies beyond the limitations of the IRRAS/SARA models. Most of the truncated valves are identifiable from the PRA documentation or the system flow diagrams. Once identified, their relative risk significance (at a failure rate of 1.0 failures per demand) can be estimated by failing the equivalent function modeled in the PRA, which is affected by the MOV failure. For example, if a normally open MOV in a pump suction line is to be evaluated in a failed closed position, but it does not specifically appear in the PRA, the change in CDF due to its failure can be approximated by the failure of the pump. This procedure can be used to evaluate valves in truncated cutsets, as well as valves that were not modeled, but only for plant systems that appear in the dominant accident sequences.

MOV failure rates are adjusted, and where necessary, functionally equivalent components are failed as well. The appropriate MOVs and components are determined through reviews of the PRAs and system flow diagrams. An additional analysis of each PRA was performed with IRRAS/SARA to identify any other systems that had no MOVs in the dominant sequences but, when failed, result in noticeable increases in the CDF. These systems were then reviewed to determine if they contained MOVs that had been eliminated during the truncation process discussed previously. System flow diagrams were then used to determine if any functionally equivalent components to these MOVs could be identified. However, no equivalent components were found for valves determined in this manner, that could be used to determine their increase in CDF when failed. Because neither the MOVs or equivalent components are in the dominant cutsets, it is likely (although not certain) that the risk-significance of mispositioning these MOVs is low.

This process should identify most of the risk-significant position-changeable MOVs, and will provide a quantitative estimate of the risk importance of mispositioning the individual MOVs. However, it should be clear that the results are not intended to be a comprehensive list of all mispositionable valves that must be included under GL 89-10.

Multiple Valve Mispositionings

In identifying valves for evaluation at BWRs, only single valve mispositionings were considered. An investigation, which included a visit to the Shoreham (a BWR-4) Control Room Simulator, revealed that no single control could operate valves in different system trains. Therefore, it was not considered credible for BWRs that an operator would inadvertently misposition more than one valve. There is multiple control of some valves in series, i.e., in the same piping with the same function. However, these are usually isolation valves where the inadvertent closing of two valves would have the same effect as closing one. Also, valves that are aligned in series with another valve having the same function, but with separate controls, were not evaluated in cases where inadvertent operation of both was required for system degradation. Inadvertent opening of one of two MOVs in series would not change the dP across it.

For the PWR plants, several pairs of valves in each plant were evaluated for the potential for simultaneous mispositioning. These valves were identified from system diagrams as similar valves in multiple train systems, whose common-cause failure (CCF) could result in significant system consequences. This CCF evaluation also considered the location of the controls for these MOVs. As in the case of BWRs, operation of valves in series, (i.e., the same piping with the same function) was not considered as part of the CCF analysis.

SAFETY SIGNIFICANCE OF MOVS

Sensitivity Study

The methodology described in the previous section can be used to determine the increase in the plant CDF, assuming that any of the identified MOVs is mispositioned and a differential pressure or flow condition exists that prevents the valve from returning to its required position. When the risk importance of the position-changeable MOVs is calculated, the failure rate of these MOVs was increased to 1.0 failures per demand. This was a simplification and can more properly be expressed as follows.

First, one assumes that an initiating event for a particular PRA accident sequence (e.g., station blackout) has occurred. For the valve to fail through the mispositioning scenario considered in this analysis, the following must occur:

1. The MOV must be moved to an incorrect position. (Probability = $P_{misposition}$)

2. There must be a high dP or high flow condition at the valve. (Probability = $P_{Hi\ dP}$)

3. The valve must then fail to reposition when (and if) recovery is attempted. (Failure Rate, FR = $FR_{reposition}$)

Thus, the correct expression to use for the failure rate of the MOVs in the PRA calculations would be

$$FR_{PRA} = P_{misposition} \times P_{Hi\ dP} \times FR_{reposition}\ .$$

As stated above, the initial calculation, performed separately for each valve, assumed that both probabilities were 1.0 and that $FR_{reposition}$ was 1.0 failure per demand. One should note, also, that even this more detailed expression is somewhat of a simplification. For example, other possibilities that could be considered are the failure of the operators to even attempt repositioning, or normal hardware failures of the MOV during an attempted repositioning.

The actual determination of probability values for $P_{misposition}$ and $P_{Hi\ dP}$ is quite difficult and beyond the scope of this study. Also $FR_{reposition}$ may not be as high as 1.0 failures per demand. Therefore, a sensitivity study was performed to determine the effect on CDF as the value

$$FR_{PRA} = P_{misposition} \times P_{Hi\ dP} \times FR_{reposition}$$

is varied between the lower base case MOV failure rate values of the PRA and the high value of 1.0 failure per demand.

The PRA base case values for MOV failure rates are generally in the range of 1×10^{-5} to 3×10^{-3} failures per demand. The sensitivity study was done for three values of FR_{PRA} between 10^{-3} and 1.0 failure per demand. This sensitivity study included only valves having a CDF for a failure rate of 1.0 failure per demand greater than two times the base case PRA CDF (with standard valve failure rates). The change in CDF for these valves at failure rates less than 1.0 failure per demand would be less than twice the base case PRA CDF, and would not be considered significant.

A summary of the results is shown in Tables 1 and 2. More detailed results and explanations of some anomalies in the tables are presented in Ruger et al. (1991) and Ruger et al. (1993). The tabulated results are presented in the form of a risk increase ratio (RIR) that represents the ratio between the CDF with the indicated valve failure rate and the CDF of the base case PRA model with the standard valve failure rate. Note that none of the identified valves for Oconee 3, for which RIRs could be obtained, had RIRs greater than 2.0. Therefore, no Oconee MOVs appear in Table 2.

The base case CDF of each PRA model is taken as the "point estimate" of the total CDF for internal events. Note that the point estimate of CDF is different from, and slightly lower than, the statistically derived mean value of CDF. The RIR is a measure of the relative risk-importance of each of the MOVs listed in the table. Valves that do not receive an automatic signal to change position, but which may be required to perform a function

by remote manual (Rem. Man.) activation, are considered as active and are so indicated. Valves that are blocked (e.g., power removed) from inadvertent mispositioning are also indicated and are included in the analysis because similar valves at other plants may not be blocked.

It should be noted, that while the maximum RIRs for unblocked MOVs are about the same order of magnitude for both PWRs and BWRs, the base case CDFs for the two PWRs considered here are significantly larger than the CDFs for the two BWRs. This difference in internal event CDF is typical for BWRs and PWRs in the U.S. (USNRC, 1990b). This was also supported by a survey of the CDFs from 20 recent Individual Plant Examinations, which included 10 PWRs and 10 BWRs. Therefore, even though the RIRs may be comparable, the actual CDFs and changes in CDF will be larger for PWRs.

Calculations for Multiple Valve Mispositioning

In addition to the single MOV mispositionings considered in Tables 1 and 2, several pairs of valves were considered to have the potential for simultaneous mispositioning resulting in CCF at PWRs. These valves were identified from the flow diagrams for systems contained in the dominant accident sequences. The valves were selected when their CCF could result in significant system consequences, such as disabling of redundant trains. The identified MOVs are shown in Table 3, which also includes the results of a sensitivity study that considers both valves of each pair to have the indicated failure rate. As a check of the completeness of the CCF valve selection process, an earlier PC-based version of the Oconee 3 PRA (NSAC, 1984), which can evaluate pairwise failures of all MOVs in the dominant sequences, was run. All of the pairs of MOVs with significant RIRs determined by this calculation were already included in Table 3, thus providing a confirmation of the valve selection process.

As expected, the RIR for multiple valve mispositionings is noticeably higher than for single valve mispositionings. However, the three probabilities contributing to the MOV failure rate discussed above are most likely lower for multiple valve events than for a single mispositioning event. This observation should be considered when evaluating the risk-significance of multiple mispositionings.

To provide some basis for evaluating the potential for the occurrence of the multiple valve failures identified in Table 3, control room drawings for the respective plants were consulted to determine the relative locations of the controls for these pairs of MOVs. Information obtained from this study is provided in Table 3. Except for the Oconee 3 EFW valves, 3C-156 and 3C-158 that have a relatively low paired RIR to start with, all other MOV pairs have controls that are in close proximity on the same control panel.

No analysis of the probability of simultaneously mispositioning these pairs of valves was performed, but this probability is expected to be small. However, the possibility of multiple valve mispositionings is worthy of consideration due to the high risk potential associated with such events.

In discussing multiple MOV mispositionings it is appropriate to consider the Davis-Besse event (USNRC, 1985a). The relevant portion of this event concerns the inadvertent pushing of the wrong two buttons, which closed two MOVs and isolated both steam generators from the emergency feedwater supply. The valves apparently could not be reopened because of high differential pressures that had developed, which then caused the torque switches in the valve operators to trip.

While this represents a significant common cause mispositioning event, the system involved is not typically found in PWRs. The MOVs involved were controlled by the steam and feedwater rupture control system (SFRCS). The SFRCS was designed as an engineered safety features actuation system for postulated transients or accident conditions initiated in the secondary side of the plant. The system senses loss of main feedwater (MFW) flow, rupture of an MFW line, and rupture of a main steamline. The safety function

Table 1. Failure rate sensitivity analysis for risk-significant MOVs (BWRs).

Number	System[a]	MOV	Active/passive	Failure rate (failures/demand)			
				10^{-2}	10^{-1}	0.5	1.0
Grand Gulf				Risk increase ratio[b]			
1	SSW	MV11	Active	1.07	2.0	5.9	10.9
2	SSW	MV1A, MV1B, MV5A, MV5B, MV18A, MV18B	Active	1.04	1.6	3.8	6.7
3	RCIC	MV68	Active	1.01	1.2	2.2	3.7
4	RCIC	MV10, MV13, MV19, MV23, MV31, MV45, MV46, MV63, MV64	Active	1.01	1.2	2.0	3.0
5	HPCS	MV1, MV4, MV12, MV15	Active	1.01	1.2	1.8	2.6
6	HPCS	MV23	Passive	1.01	1.2	1.8	2.6
Peach Bottom				Risk increase ratio[b]			
7	HPCI	MV14, MV15, MV16, MV19	Active	1.01	1.2	1.8	2.6
8	HPCI	MV17, MV57, MV58	Active	1.01	1.1	1.7	2.4
9	HPCI	MV20	Passive	1.01	1.1	1.7	2.4
10	SLC	Pump suction	Active	1.05	1.8	4.9	8.9

a. System acronyms: HPCI—high-pressure coolant injection system, HPCS—high-pressure core spray system, RCIC—reactor core isolation cooling system, SLC—standby liquid control system, SSW—standby service water system.

b. The risk increase ratio indicated in the table represents the ratio between the CDF with the failure rate of that valve set to the indicated value and the CDF of the base-case PRA model with the standard valve failure rate. The "point estimate" base case CDF is 2.06×10^{-6} events/Rx yr for Grand Gulf and 3.62×10^{-6} events/Rx yr for Peach Bottom.

Table 2. Failure rate sensitivity analysis for risk significant MOVs (PWR).

				Failure rate (failures/demand)			
Number	System[a]	MOV	Active/passive	10^{-2}	10^{-1}	0.5	1.0
Surry 1				Risk increase ratio[b]			
1	ACC	1865A	Active	1.1	2.6	8.8	16.6
2	ACC	1865B	Active	1.1	2.6	8.8	16.6
3	ACC	1865C	Active	1.1	2.6	8.8	16.6
4	LPI	1890C	Passive[c]	1.5	5.6	24.4	47.9
5	LPR	1860A	Active	1.03	1.5	3.3	5.7
6	LPR	1862A	Active	1.02	1.5	3.3	5.7
7	LPR	1890A	Passive[d]	1.03	1.4	3.1	5.2
8	HPI	1350	Active[e]	1.02	1.2	2.1	3.1

a. System acronyms: ACC—accumulator system, HPI—high-pressure injection system, LPI—low-pressure injection system, LPR—low-pressure recirculation system.

b. The risk increase ratio indicated in the table represents the ratio between the CDF with the failure rate of that valve set to the value at the top of the failure rate column and the CDF of the base case PRA model with the standard valve failure rate. The "point estimate" base case CDF is 3.20×10^{-5} events/Rx yr for Surry 1 and 1.78×10^{-5} events/Rx yr for Oconee 3.

c. Open, power removed.

d. Closed, power removed.

e. Power removed manually.

Table 3. Sensitivity analysis for potential common-cause failure risk significant MOVs (PWRs).

				Failure rate (failure/demand)				
Number	System[a]	MOVs	Active/passive	10^{-2}	10^{-1}	0.5	1.0	Relative control locations
Surry 1								
1	ACC	1865B&C	Active	1.3	3.9	12.7	16.6	Adjacent
2	HPI	1115B&D	Active	1.00	1.6	15.7	59.8	Adjacent
3	LPI	1864A&B	Active	1.01	1.6	13.3	48.4	In close proximity
4	LPR	1862A&B	Active	1.03	1.9	14.5	48.0	In close proximity
5	PPRS	1535 & 36	Active	0.99	1.02	1.2	1.4	Adjacent
Oconee 3								
1	HPI	HP-24 & 25	Active	1.00	1.5	12.2	46.0	In close proximity
2	LPI	LP-19 & 20	Active	1.01	1.9	20.9	79.0	Adjacent
3	LPI	LP-12 & 14	Passive	1.00	1.4	11.0	41.0	Adjacent
4	LPI	LP-17 & 18	Active	1.00	1.5	11.1	41.0	Adjacent
5[b]	LPI	LP-5 & 8	Passive	1.4	4.9	20.6	50.0	Adjacent
6[b]	LPI	LP-21 & 22	Active	1.4	4.9	20.6	50.0	Adjacent
7[c]	EFW	3C-156 & 158	Active	0.97	1.02	1.6	4.0	On different vertical back panels

a. System acronyms: ACC—accumulator system, EFW—emergency feedwater system, HPI—high-pressure injection system, LPI—low-pressure injection system, LPR—low-pressure recirculation system, PPRS—primary pressure relief system.

b. Simulated by failure of pumps 3LP-P3A&B.

c. Simulated by the failure of all EFW pumps.

of the SFRCS is to provide safety actuation signals to equipment that will isolate the steam flow from the steam generators, isolate the MFW flow, and start and align the auxiliary feedwater (AFW) system. Therefore, the inadvertent manual remote actuation of the wrong switches in the SFRCS signalled that both generators had experienced a steamline break or leak. The system responded, as designed, to isolate both steam generators. This response defeated the safety function of the AFW system, which was needed for the event.

Neither Surry 1 or Oconee 3 have an SFRCS, nor is this system typical of other PWRs. Surry 1 has a large redundancy of MOVs isolating the AFW pumps from the steam generators. In fact, it would take six independent actions to cause such an isolation. For Oconee 3, four independent MOV mispositionings would be required to isolate the EFW pumps from the steam generators.

SUMMARY

MOVs are generally acknowledged to be important components in nuclear power plants when evaluated using either conventional engineering judgment or PRA type risk assessment techniques. The calculations performed as part of the value-impact assessment (Higgins et al., 1988) for GL 89-10 showed that large risk increases occurred when groups of MOVs had their failure rates increased.

After the issuance of both Bulletin 85-03 and GL 89-10, subsequent testing and analysis identified significant engineering problems with MOVs, requiring extensive modifications and repairs to return the valves to a fully operable status. A significant amount, but not all, of the required work has already been completed.

One area not fully resolved is the consideration of valve mispositioning. Full consideration of this issue is difficult from an engineering analysis standpoint due to the many possible scenarios for mispositioning, some of which will have higher differential pressures and flows than the typical valve design basis. Questions naturally arose from industry as to the risk-significance and the diminishing safety returns of fully analyzing and addressing this issue. Was the USNRC requiring too much in this instance?

The studies described herein developed risk measures that allow a reasonable evaluation of the importance of individual and pairwise mispositioning events. Informed judgements can thus be made about the need for further actions in this area. As a result, it was determined in Supplement 4 to GL 89-10 (USNRC, 1992) that BWRs need not consider mispositioning further. PWR plants had higher risk values, and the final determination for PWRs was still under consideration when this paper was written.

Care should be used in employing these results. The purpose of this study was to provide input to resolution of the industry's questioning of the risk-significance of the MOV mispositioning issue. The results provide a representative measure of the risk-significance of the issue derived from a sampling of PRAs. The study is limited in the number of valves by plant-specific considerations and the characteristics of the PRA models used. Different plants may employ different valve configurations than the two plants considered here. In addition, individual plants often have plant-specific vulnerabilities that determine which sequences or cutsets are risk-significant. Also, PRA modeling assumptions and the PRA truncation process may have eliminated some risk-significant MOVs from the models used. For these reasons, the results should be used to obtain a representative measure of the risk-significance attached to the mispositioning of MOVs in BWRs and PWRs and not to determine a restrictive list of position-changeable valves to be included under GL 89-10.

Given these constraints, the risk increase ratios resulting from these failure rate sensitivity studies can be used as a basis for a judgmental determination of the risk-significance on the MOV mispositioning issue for BWRs and PWRs.

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Session 3C

Valve Performance and Testing

Session Chair
Chris Hansen
Yankee Atomic Electric

Dynamic Testing of POSI-SEAL Motor-Operated Butterfly Valves Using Strain Gages

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ABSTRACT

Utilities operating nuclear power plants recognize that the correct functioning of all motor-operated valves, and particularly those in safety-related systems, is of paramount importance. The U.S. Nuclear Regulatory Commission has issued Generic Letter 89-10 relative to this concern. Operability must be demonstrated under design-basis conditions.

In order to demonstrate operability of motor-operated butterfly valves, the valve stem torque must be determined. The valve stem torque is a function of seat material, stem packing, stem bearing friction, and hydrodynamic lift and drag.

The total valve operating hydrodynamic torque can be predicted using the valve manufacturer's data and the differential pressure. In order to validate the valve manufacturer's data, the actual total valve hydrodynamic torque is measured using strain gages mounted directly on the valve stem.

This paper presents the results of comparing the predicted total valve operating hydrodynamic torque with the actual total valve operating hydrodynamic torque for six POSI-SEAL Class 150 high performance butterfly valves.

INTRODUCTION

Generic Letter (GL) 89-10 requires that licensees conduct in situ differential pressure (DP) testing to verify the performance of all motor-operated valves (MOVs) under design-basis conditions. Illinois Power contracted Teledyne Brown Engineering—Engineering Services (TBE) to perform DP testing of six motor-operated butterfly valves to support the GL 89-10 program at Clinton Power Station (CPS).[a] CPS is a 985 MWe boiling water reactor located in central Illinois about 175 miles south of Chicago.

A total of 39 butterfly MOVs were included in the original GL 89-10 program. All of them are POSI-SEAL Class 150 high performance butterfly valves with single offset disc design.

The total hydrodynamic torque curve for POSI-SEAL Class 150 STD Rating butterfly valves can be predicted using an analytical expression consisting of three torque components. This procedure is described in a POSI-SEAL Technical Bulletin (1987).

The three torque components consist of stem packing torque, stem bearing friction torque and disc hydrodynamic lift and drag torque. All three torque components are a function of valve size. The stem packing torque (T1) is a constant function of the packing material. The stem bearing

a. Unpublished technical report, TR-21335A-I, Revision 0, Teledyne Brown Engineering.

friction torque (T3) varies linearly with the differential pressure. The disc hydrodynamic lift and drag torque (T4 or T5) is a function of flow direction, valve disc angle and differential pressure. POSI-SEAL provides tabular data to calculate the three torque components described above.

In order to validate this torque prediction methodology, TBE measured the actual stem torque of the selected POSI-SEAL motor operated butterfly valves using strain gages. The selected valves were subjected to near design-basis differential pressures and flows.

METHOD

The actual stem torque of the selected motor-operated butterfly valves was measured using strain gages mounted directly on the valve stem. In addition, the upstream pressure, downstream pressure, flow, and valve stem rotation were measured simultaneously. TBE used the QUIKLOOK[b] data acquisition system to record the measurements. The QUIKLOOK data acquisition system measures voltage signals at a rate of 1,000 samples per second on each of its eight channels.

The differential pressure was calculated from the upstream and downstream pressures. The differential pressure was used to predict the total valve operating hydrodynamic torque as described the POSI-SEAL bulletin (1987). This prediction was compared with the actual valve torque measured using strain gages mounted on the valve stem. TBE used DADiSP[c] to perform the comparison. DADiSP is a graphical signal-analysis program (DSP Development Corporation, 1991).

b. QUIKLOOK and Quick Stem Sensor are registered trademarks of Teledyne Brown Engineering.

c. DADiSP is a registered trademark of DSP Development Corporation.

Stem Torque

TBE measured stem torque using the Quick Stem Sensor (QSS)[b] mounted directly on the valve stem. The QSS is a patented device consisting of strain gages, circuitry, and prewired connectors that is applied to the smooth part of the valve stem using a layer of adhesive. After mounting and curing, the sensitivity of the QSS can be determined by calibration or calculation, depending on accuracy requirements. The sensitivity is the relationship between the output voltage of the QSS (mV/V) and the applied load (ft-lb).

For the testing performed at CPS,[d] the torque sensitivity of the QSS was calculated as

$$\text{Torque sensitivity} = 16.363 \frac{D^3E}{G.F.(1 + \mu)} \cdot \frac{\text{ft-lb}}{\text{mV/V}} \quad (1)$$

where

D = stem diameter (in.)

E = Young's modulus of stem material/10^6

μ = Poisson's ratio of stem material

G.F. = gage factor of strain gage.

The torque sensitivity was calculated for each of the selected valves using the QSS Installation Log. The calculated torque sensitivity was entered into the QUIKLOOK data acquisition system. TBE used the QUIKLOOK data acquisition system to record the stem torque measurements. In addition, TBE used QUIKLOOK to establish a zero reference point for the stem torque. The zero reference point was selected during a static stroke. The static stroke was adjusted by a constant (zero offset) such that the zero reference point equally bisected the closing and opening packing torques. The zero offset was entered

d. Unpublished technical report, A722-1, Revision 0, Teledyne Brown Engineering.

into the QUIKLOOK data acquisition system for automatic adjustment of any further static or dynamic torque measurements.

Stem Rotation

TBE measured stem rotation using a calibrated linear position transducer. In addition, the stroke time was determined from the measured stem rotator. The linear position transducer was fastened to the nonrotating portion of the HBC unit. The linear position transducer cable was extended around the rotating portion of the HBC unit and fastened to the position indicator. Stem rotation is calculated as

$$\theta = \frac{180}{\pi} \frac{L}{R} \text{ (degrees)} \quad , \qquad (2)$$

where

L	=	arc length measured by linear position transducer
R	=	radius of rotating portion of HBC unit
0 degrees	=	$\theta \leq 90$ degrees
0 degrees	=	valve
900 degrees	=	valve.

Differential Pressure

CPS provided calibrated pressure transducers for the valve testing. CPS installed upstream and downstream pressure transducers as close as possible to the valve being tested. CPS wired the pressure transducers to output a 1 – 5 Vdc signal representing zero to full-scale pressure, and provided TBE with the applicable full-scale output. TBE calculated differential pressure across the valve by subtracting the adjusted downstream pressure from the adjusted upstream pressure using Equation (7).

Flow

CPS provided a calibrated ultrasonic flow meter for the valve testing. CPS installed the flow meter as close as possible to the valve being tested. CPS wired the flow meter to output a 0 – 10 Vdc signal representing zero to full-scale output, and provided TBE with the applicable full-scale output. Flow is not a direct part of the torque prediction methodology; however, the flow was used to calculate the pressure losses associated with the components downstream and upstream of the valve between the pressure sensors.

The downstream and upstream pressure losses were calculated (Crane Company, 1988) as

$$PL_{UP} = \varrho K_{UP} \left[\frac{Q}{236d^2}\right]^2 \quad , \qquad (3)$$

$$PL_{DOWN} = \varrho K_{DOWN} \left[\frac{Q}{236d^2}\right]^2 \quad , \qquad (4)$$

where

ϱ	=	62.4 lbm/ft^3
Q	=	flow rate
d	=	valve nominal diameter (in.)
K_{up}	=	flow resistance coefficient corresponding to components between upstream tap and valve
K_{DOWN}	=	flow resistance coefficient corresponding to components between valve and downstream pressure tap.

Once the pressure losses were calculated, the downstream and upstream pressure traces were independently adjusted as

$$PA_{UP} = P_{UP} - PL_{UP} \pm PH_{UP} \quad , \qquad (5)$$

$$PA_{DOWN} = P_{DOWN} + PL_{DOWN} \pm PH_{DOWN} \qquad (6)$$

where

PA_{UP}, PA_{DOWN} = adjusted upstream and downstream pressure trace

P_{UP}, P_{DOWN} = upstream and downstream pressure acquired using QUIKLOOK

PL_{UP}, PL_{DOWN} = upstream and downstream pressure loss adjustments

PH_{UP}, PH_{DOWN} = upstream and downstream transducer elevation adjustments.

The differential pressure was calculated as

$$DP = PA_{UP} - PA_{DOWN} \ . \qquad (7)$$

Because the pressure loss adjustments are analytical estimates, engineering judgment was used. If necessary, the upstream and downstream pressure traces were adjusted such that the differential pressure was approximately zero when the valve was fully opened under maximum flow conditions and the differential pressure was equal to (P_{UP} - P_{DOWN}) when the valve was fully closed under no-flow conditions (for $PH_{UP} = PH_{DOWN} = 0$).

ACCURACY

The total accuracy of the stem torque, differential pressure, stem rotation, and flow measurements is the SRSS of the individual transducers with the QUIKLOOK data acquisition system. The accuracy of the QUIKLOOK data acquisition system varies with the type of transducer (strain gage transducer, single-ended voltage transducer, differential voltage transducer).

Stem Torque

TBE measured stem torque using the Quick Stem Sensor mounted directly on the valve stem. For the testing performed at CPS, the sensitivity of the QSS was calculated. The accuracy of a QSS with a calculated sensitivity is ±9.8% of the reading (2.4 sigma). The QUIKLOOK data acquisition system has an accuracy of ±1.0% of the reading for strain gage transducers. Therefore, the total accuracy of a QSS with a calculated sensitivity using the QUIKLOOK data acquisition system is

$$\sqrt{(9.8)^2 + (1.0)^2} = \pm\ 9.85\% \text{ of the reading} \ . \qquad (8)$$

In order to be conservative, all QSS torque measurements were increased by 9.85% (multiplied by 1.0985).

Stem Rotation

TBE measured stem rotation using a commercially available linear position transducer. The stated accuracy of the linear position transducer is ±0.10% of full scale where full scale is 30 in. The accuracy of the linear position transducer does not affect the magnitude of the measured stem torque; therefore, the accuracy is stated but not used.

Differential Pressure

CPS provided calibrated pressure transducers for the valve testing. The calibrated accuracy of the pressure transducers is ±1.5% of the reading. The QUIKLOOK data acquisition system has an accuracy of 0.25% of the reading for single-ended voltage transducers.

Therefore, the total accuracy of the pressure transducers using the QUIKLOOK data acquisition system is

$$\sqrt{(1.5)^2 + (0.25)^2} = \pm\ 1.52\% \text{ of the reading} \ . \qquad (9)$$

In order to be conservative, all differential pressure measurements were decreased by 1.52% (multiplied by 0.9848).

Flow

CPS provided a calibrated flow meter for the valve testing. The calibrated accuracy of the flow

meter is $\pm 3.0\%$ of the reading. Flow is not a direct part of the torque prediction methodology; however, the flow was used to calculate the pressure losses associated with the components downstream and upstream of the valve between the pressure sensors. Because the pressure loss adjustments were analytical estimates, TBE did not apply the stated calibration accuracy to the flow measurements.

VALVE SELECTION

A total of 39 butterfly MOVs were included in the original GL 89-10 program at CPS. All of them are POSI-SEAL Class 150 high performance butterfly valves with the single offset disc design. Six test valves were randomly selected to be a representative sample of the entire butterfly MOV population (Table 1). The six butterfly MOVs selected for testing were installed in two different systems. These systems are described as follows:

- Shutdown service water system (SX): The SX system is designed to provide a source of cooling water from a man-made lake to plant utilities that are required to safely shut down the reactor following a loss of coolant accident or loss of offsite power.

- Fuel pool cooling and cleanup system (FC): The FC system is designed to remove decay heat from the spent fuel assemblies, maintain pool water level, clean the water to minimize fission product concentration and maintain clarity for fuel handling, and to clean the suppression pool water.

The stem material for the selected valves is 17-4PH Cond H1075. The material properties for 17-4PH Cond H1075 are extracted from The *Aerospace Structural Metals Handbook* (1988) as

$$E = 29.1 \times 10^6$$

$$\mu = 0.291 \quad .$$

The seat material for the selected valves consists of a TEFZEL seal ring and EPR O-ring. The bearing material for the selected valves consists of 316 MS (graphite-impregnated stainless steel).

RESULTS

Table 2 summarizes the static and dynamic tests performed by TBE on the six selected POSI-SEAL MOVs. Table 3 summarizes the predicted and actual total valve operating hydrodynamic torque for the as-tested conditions. The tested differential pressure, tested flow, stroke time, actual torque, and predicted torque (Column 3) are the maximum values independent of valve angle extracted from the graphs presented in Appendices A through G. The predicted torques (Columns 1 and 2) were calculated based on tabular data supplied by POSI-SEAL. TBE used DADiSP to perform all of the calculations presented in these appendices. Each appendix is organized as follows:

- Piping system isometric
- Static worksheet
  - Actual torque versus valve angle
- Dynamic worksheets
  - Actual torque and predicted torque versus valve angle[e]
  - Upstream pressure, downstream pressure, and differential pressure versus valve angle[e]
  - Flow rate versus valve angle
- POSI-SEAL
  - T4 or T5 versus valve angle.

e. Quantities are superimposed

Table 1. Valve sample description.

Valve number	POSI-SEAL drawing number	Valve size (in.)	Seal location	Packing material
1FC016B	16204-16	8	Upstream	Asbestos free
1FC024B	16204-16	8	Downstream	Graphite
1SX020B	16204-23	12	Downstream	Graphite
1FC026A	16204-8	14	Upstream	Asbestos free
1FC026B	16204-8	14	Up/down[a]	Asbestos free
1SX-14A	16204-26	20	Downstream	Graphite

a. Unable to positively establish seal location, so both are presented.

Table 2. Static and dynamic test summary.

Valve no.	QUIKLOOK reference	Test date	Static	Dynamic	Comments
1FC016B	V1D3489315[a]	12/14/93	X	X	Low DP
	V1D3489316	12/14/93	–	X	High DP
	V1D3489317[a]	12/14/93	–	–	–
1FC024B	V1D3489321[a]	12/14/93	X	X	Low DP (essentially static)
	V1D3489322	12/14/93	–	X	High DP
	V1D3489323[a]	12/14/93	–	–	–
1SX020B	V1D3489302[a]	12/15/93	X	X	Flow channel overranged
	V1D3489306	12/15/93	–	X	–
	V1D3489308[a]	12/15/93	–	–	–
1FC026A	V1D3509307[a]	12/16/93	X	X	–
	V1D3509306	12/16/93	–	X	–
	V1D3509310[a]	12/16/93	–	–	–
1FC026B	V1D2299304[a]	08/17/93	X	X	Exercise strain gages
	V1D2299305	08/17/93	–	X	–
	V1D2299307[a]	08/17/93	–	–	–
1SC014A[b]	V1D2319320	08/19/93	–	X	Exercise strain gages
	V1D2319321	08/19/93	–	X	Closing, reverse flow
	V1D2319322[a]	08/19/93	–	X	Opening
	V1D2319324[a]	08/19/93	–	X	Closing, reverse flow
	V1D2319328	08/19/93	–	X	Opening
	V1D2319329	08/19/93	–	X	Closing, reverse flow

a. Results graphically presented in appendices.

b. Valve operation linked to pump operation.

Table 3. Predicted and actual total valve operating hydrodynamic torque for as-tested conditions.

Valve description				DP (psig)			Tested flow		Stroke time	Actual torque (ft-lb)		Predicted torque (ft-lb)		
Valve number	Valve size (in.)	Stem size	Seal location	Tested	Design	Ratio	(gpm)	(ft)	(s)	Static[a]	Dynamic[a]	—[b]	—[c]	—[d]
1FC016B	8	0.875	Upstream	123	157	0.78	2,197	14.1	53[e]	+119 −259	+187 −290	89	122	142
1FC024B	8	0.875	Downstream	120	158	0.76	2,226	14.2	55[e]	+16 −21	+143 −72	78	110	136
1SX020B	12	1.250	Downstream	100	150	0.66	5,068	14.4	61	+326 −461	+351 −528	146	230	345
1FC026A	14	1.375	Downstream	126	144	0.88	2,444	5.7	58	+286 −184	+382 −413	191	334	345
1FC026B	14	1.375	Both	65	147	0.44	3,100	7.2	59	+120 −277	+274 −281	191	265	284 195
1SX014A	20	2.000	Downstream	115	154	0.75	9,308	10.3	58	N/A	+1,409 −1,122	321	707	1,940

a. QSS sign convention: + = opening; − = closing.

b. (1) POSI-SEAL opening/closing torque: T1 + T2.

c. (2) POSI-SEAL opening/closing torque: T1 + T2 + (T3 * DP).

d. (3) POSI-SEAL total opening hydrodynamic torque: T1 + (T3 * DP) + (T4 * DP) for seal down; T1 + (T3 * DP) + (T5 * DP) for seal up.

e. Maximum open at 80 degrees.

CONCLUSIONS

Illinois Power contracted TBE to perform dynamic testing of six safety-related butterfly MOVs to support the U.S. Nuclear Regulation Commission letter GL 89-10 program at the Clinton Power Station.

Table 3 illustrates that the predicted torque results are unconservative with respect to the actual torque results measured using strain gages mounted on the stem for five out of the six valves tested. This observation warrants further investigation of the applicability of the analytical methods for conservatively predicting stem torque.

After the results in Appendices A through G were reviewed, the following observations were made:

- Four of the six valves tested had significant upstream disturbances near the valve; however, the maximum actual hydrodynamic torques occurred at small disk opening angles (30 degrees) where the effect of a flow disturbance was considerably less than when the valve was fully open (90 degrees).

- The actual closing torques for four out of the six valves tested were excessive. These values may be linked to improper settings of limit switches.

- The actual static and dynamic torque traces for valve 1FC016B exhibited an anomaly at approximately 40 degrees for both the static and dynamic tests. This anomaly may be linked to a "high spot" on the stem or problems related to the valve bearings.

- The dynamic torque trace for valve 1FC024B exhibited "roughness" when compared with the static torque trace and other valve dynamic torque traces. This roughness may be related to the valve bearings.

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DSP Development Corporation, 1992, "The DADiSP Worksheet, Reference Manual, November 1991," Version 3.01B, Cambridge, MA, September 15.

POSI-SEAL, 1987, *A-Series Operating Torque and Actuator Sizing*, Technical Bulletin 1A, North Stonington, CT, September.

Appendices A through G

Results for 1FC016B 8-in. MOV

Results for 1FC024B 8-in. MOV

Results for 1SX020B 12-in. MOV

Results for 1FC026A 14-in. MOV

Results for 1FC026B 14-in. MOV

Results for 1SX014A 20-in. MOV

No Static Stroke Available for Valve 1SX014A

Results for 1FC016B 8-in. MOV

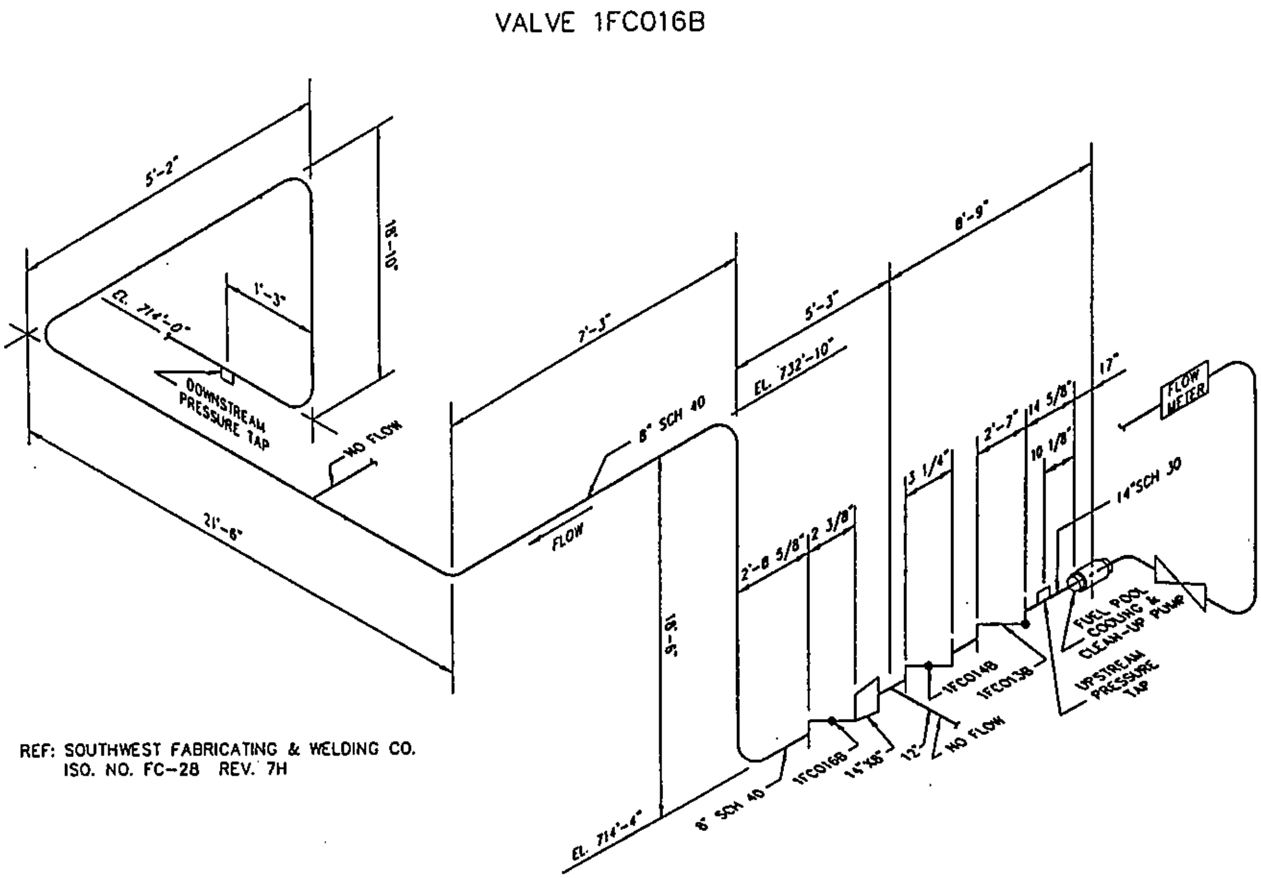

Figure A-1. Results for 1 FC016B 8-in. MOV.

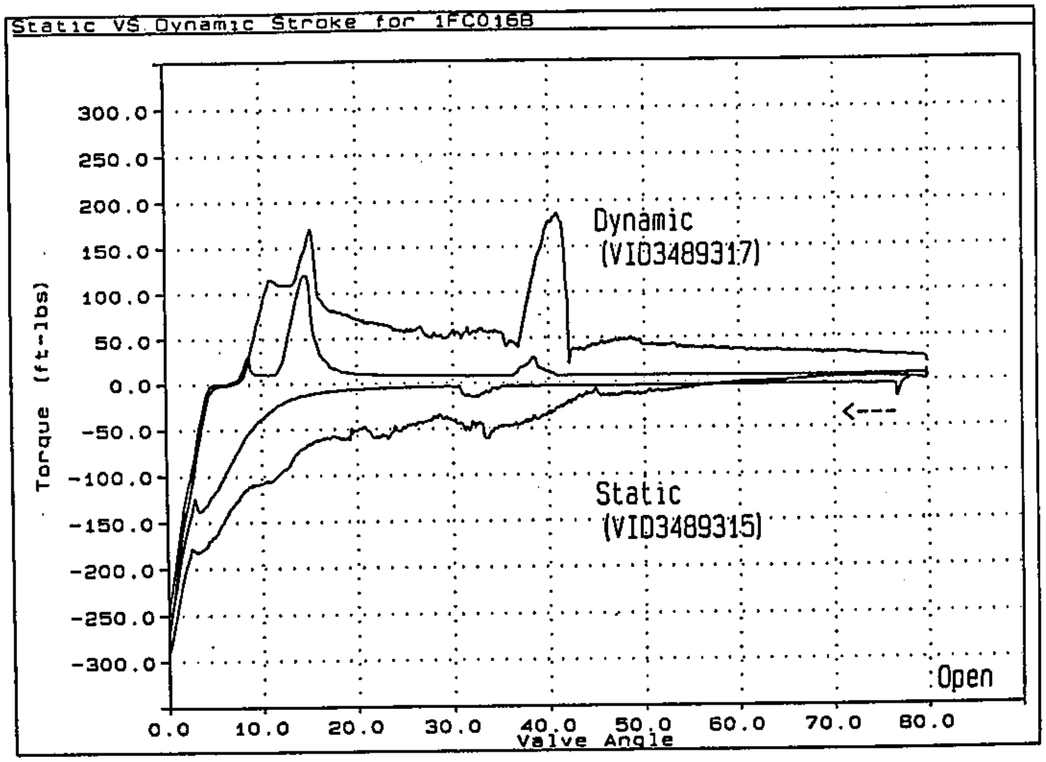

Figure A-2. Results for 1 FC016B 8-in.. MOV.

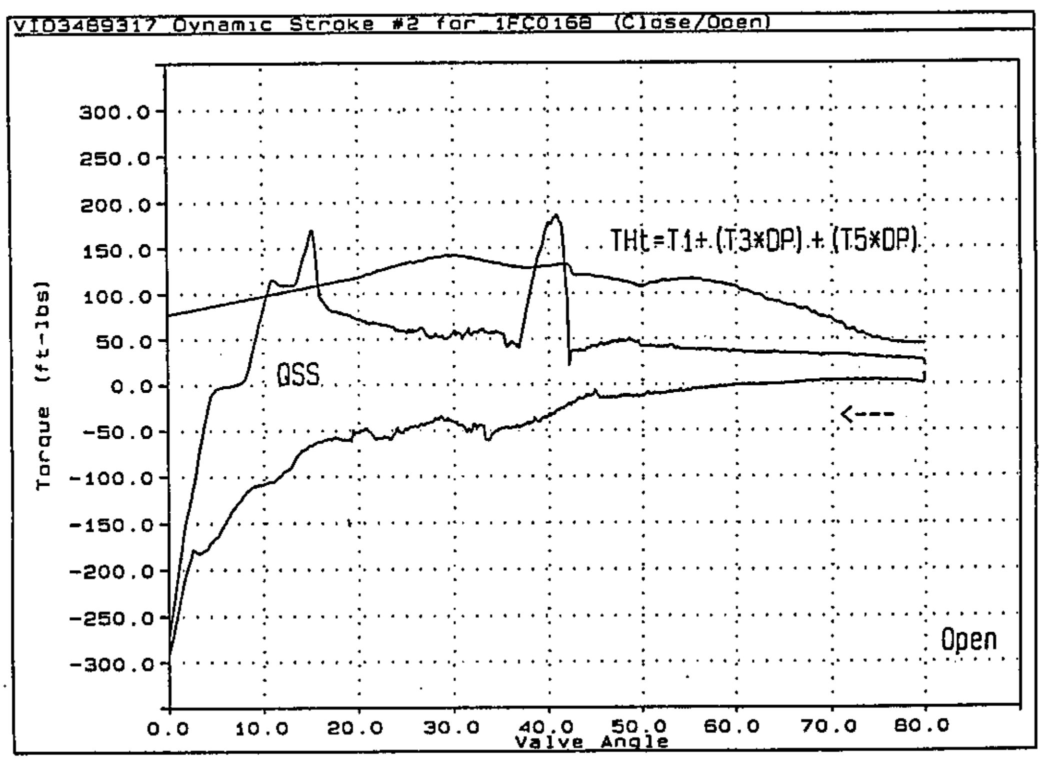

Figure A-3. Results for 1 FC016B 8-in. MOV.

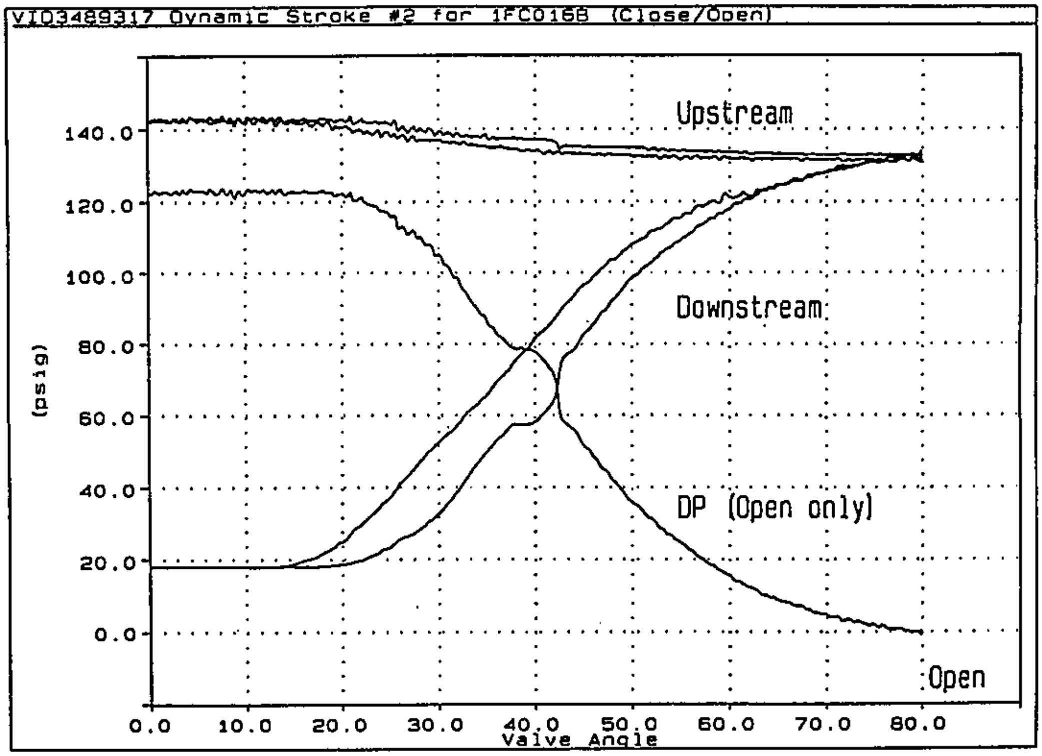

Figure A-4. Results for 1 FC016B 8-in. MOV.

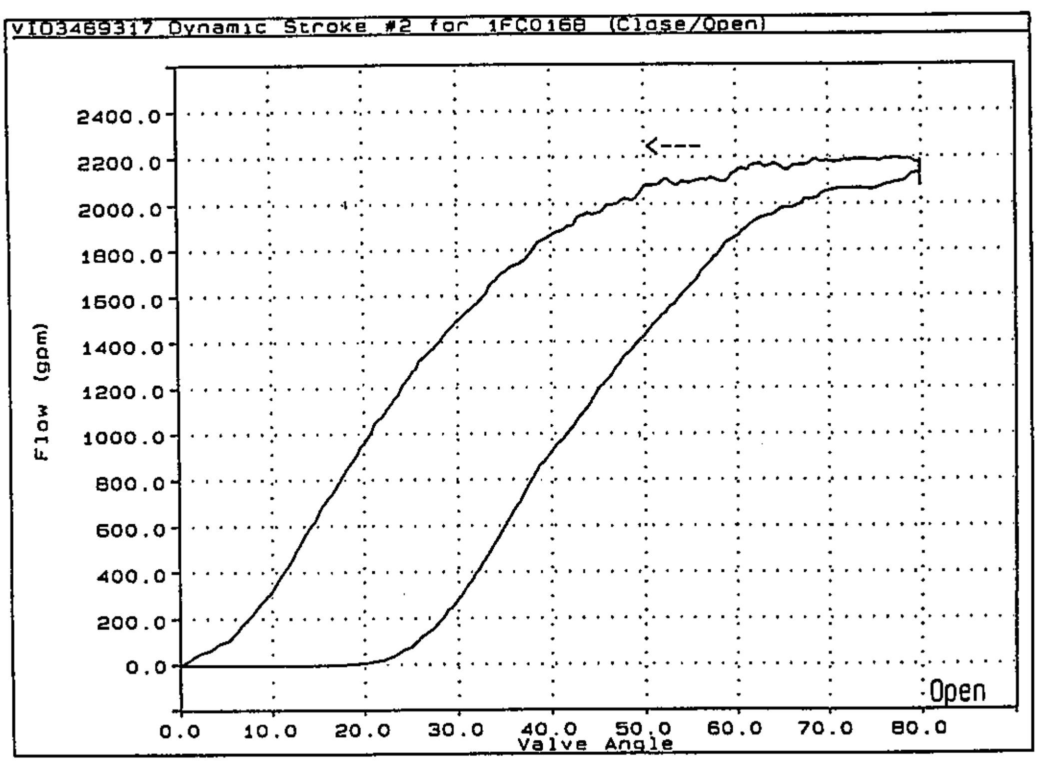

Figure A-5. Results for 1 FC016B 8-in. MOV.

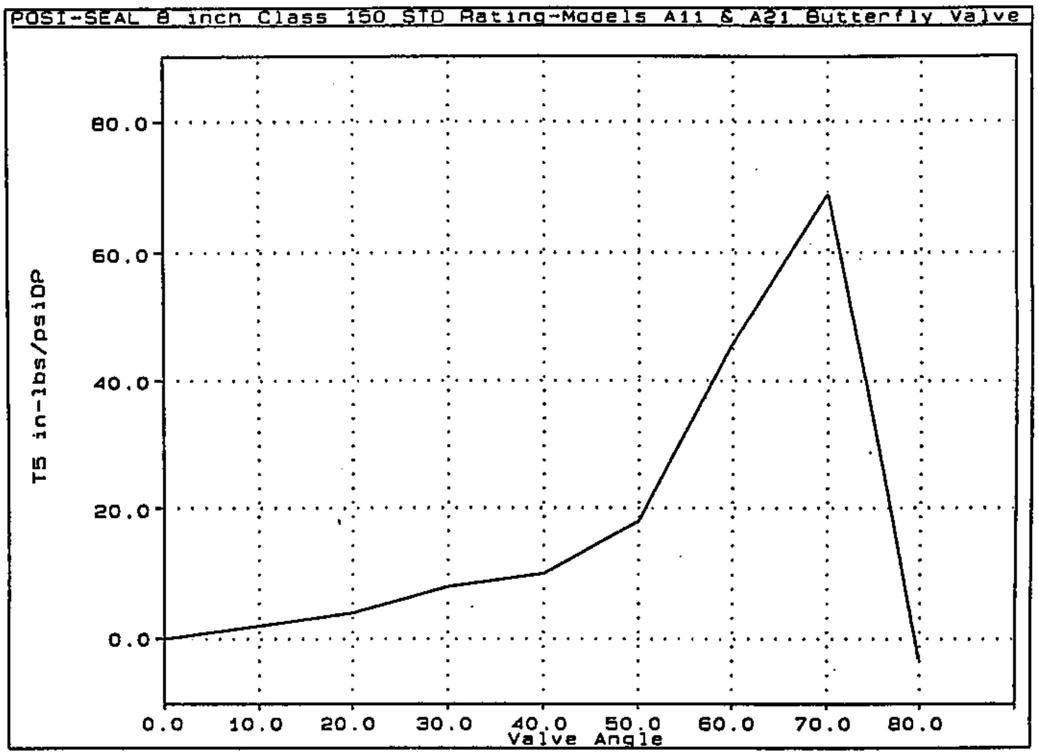

Figure A-6. Results for 1 FC016B 8-in. MOV.

Results for 1FC024B 8-in. MOV

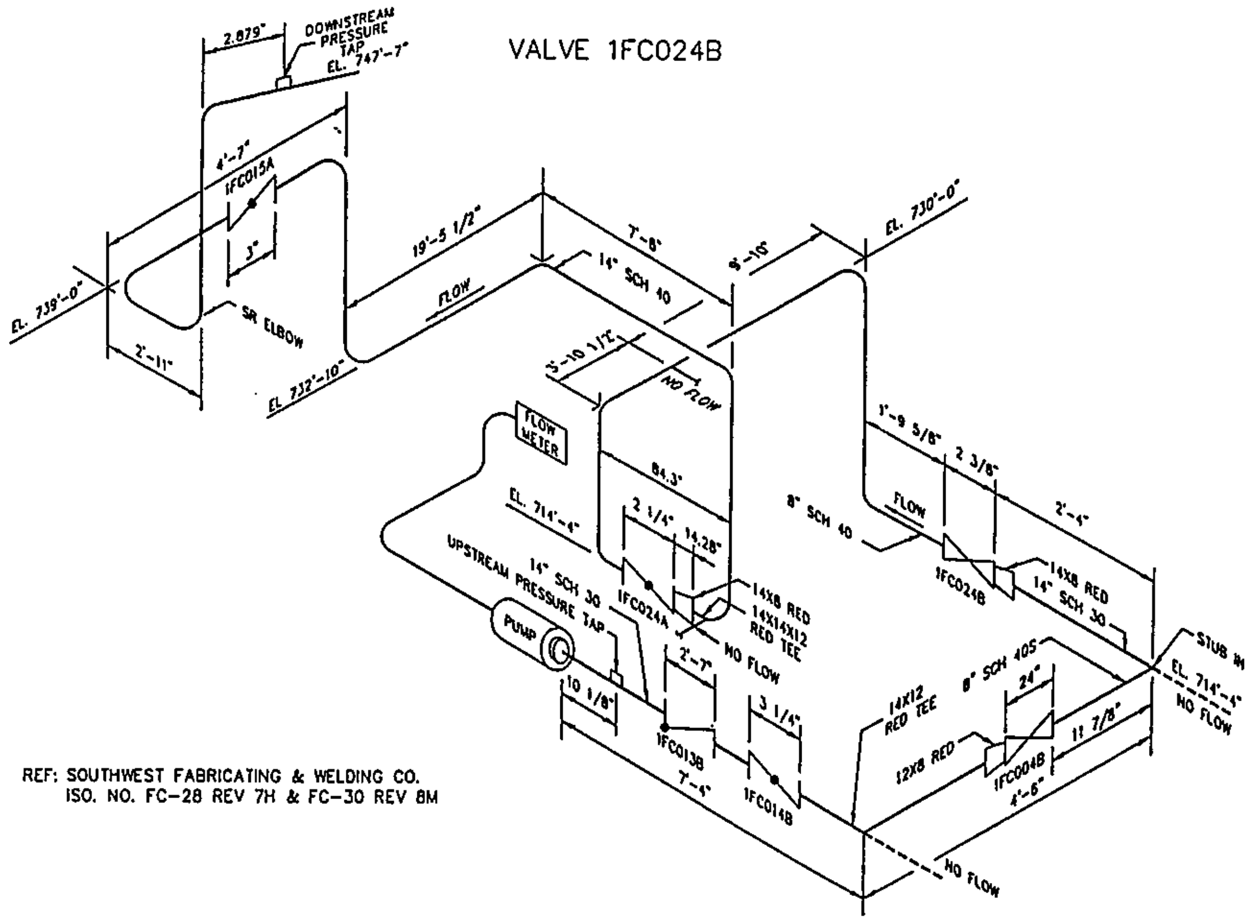

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Figure B-1. Results for 1FC024B 8-in. MOV.

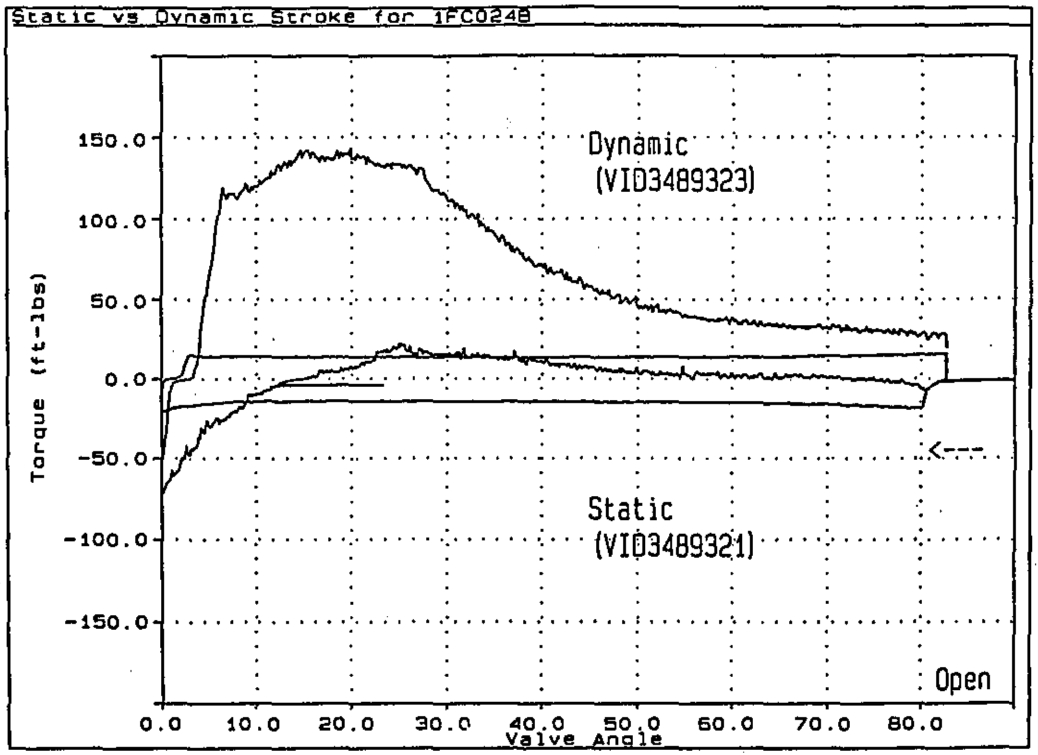

Figure B-2. Results for 1FC024B 8-in. MOV.

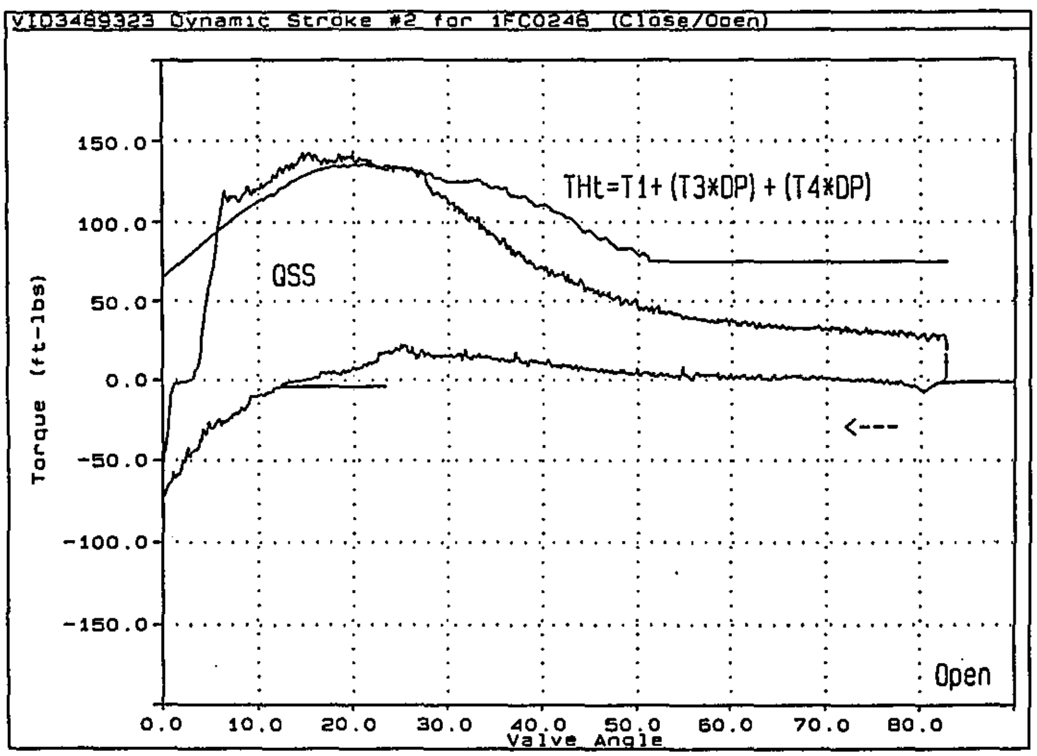

Figure B-3. Results for 1FC024B 8-in. MOV.

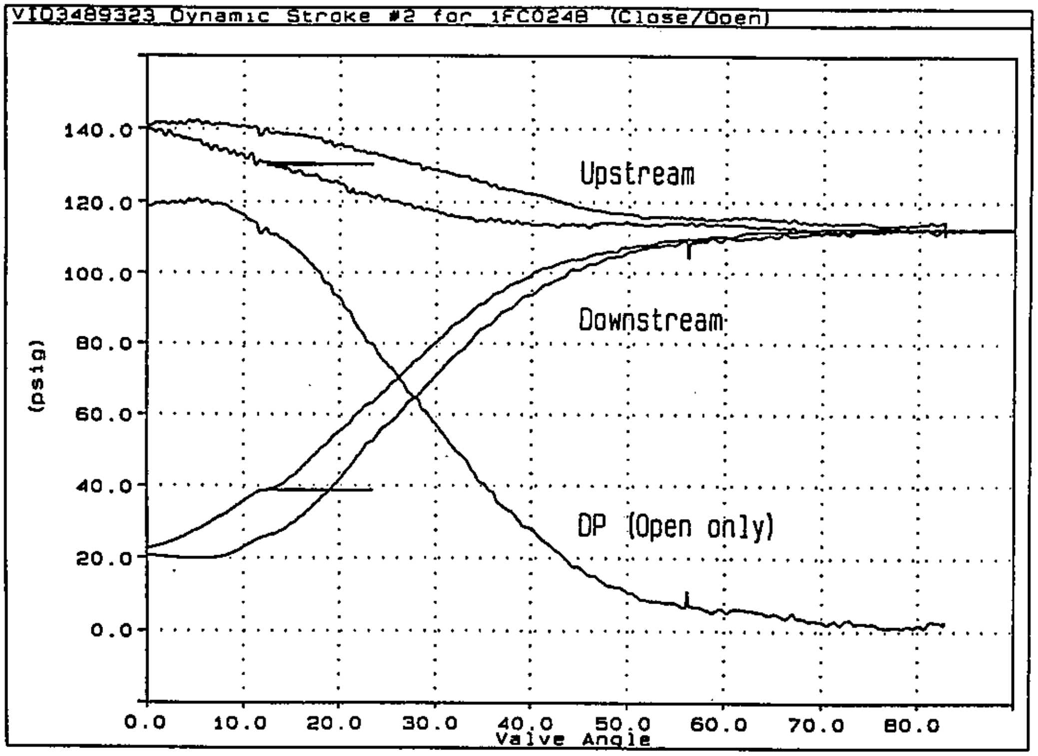

Figure B-4. Results for 1FC024B 8-in. MOV.

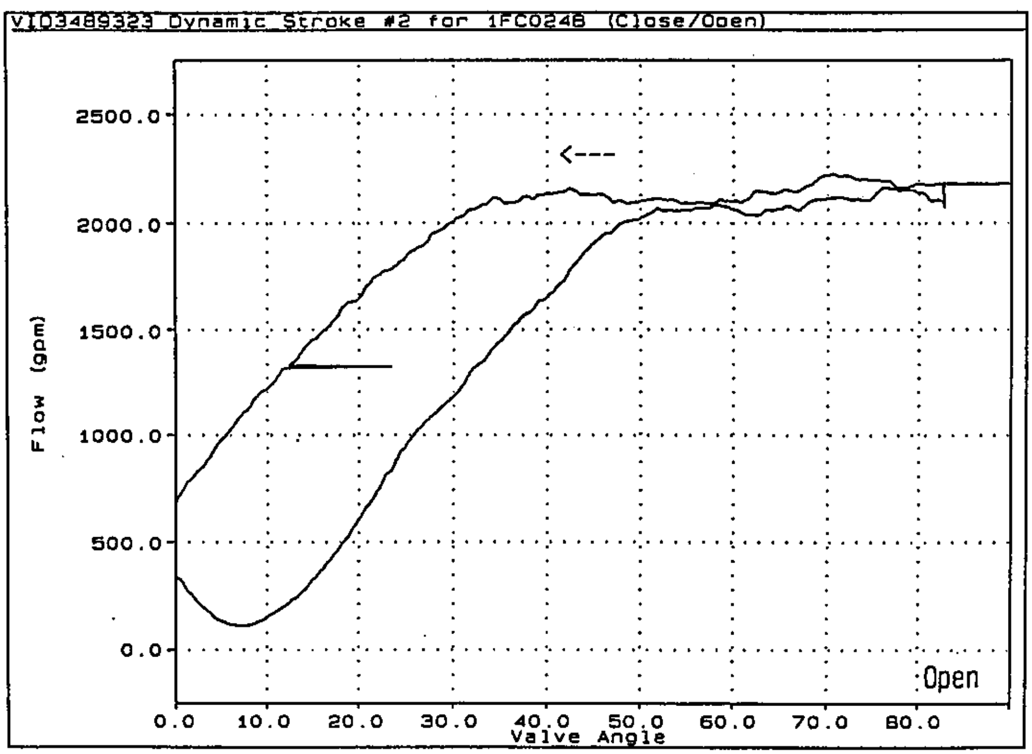

Figure B-5. Results for 1FC024B 8-in. MOV.

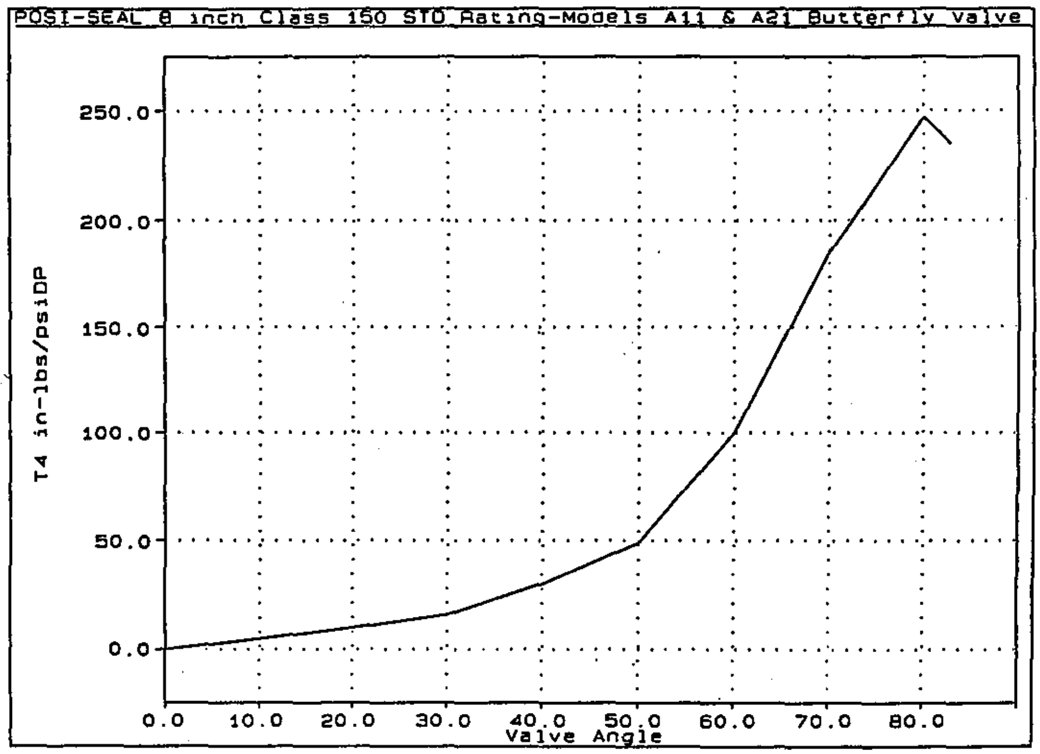

Figure B-6. Results for 1FC024B 8-in. MOV.

Results for 1SX020B 12-in. MOV

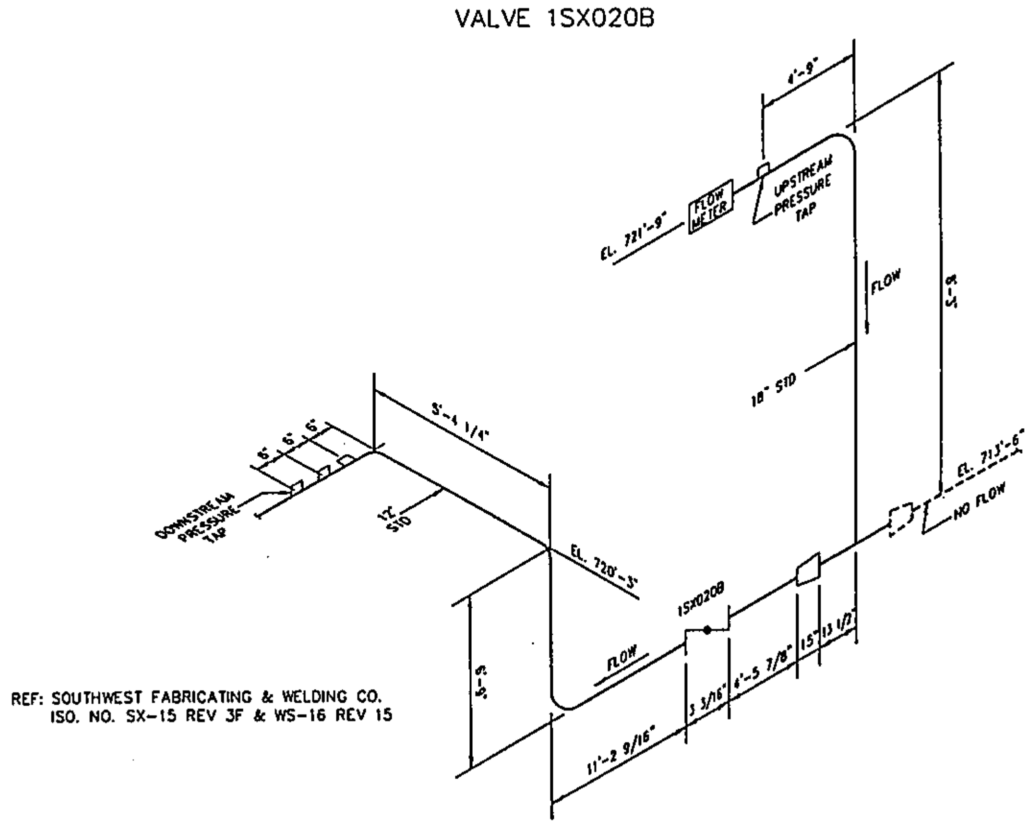

Figure C-1. Results for 1SX020B 12-in. MOV.

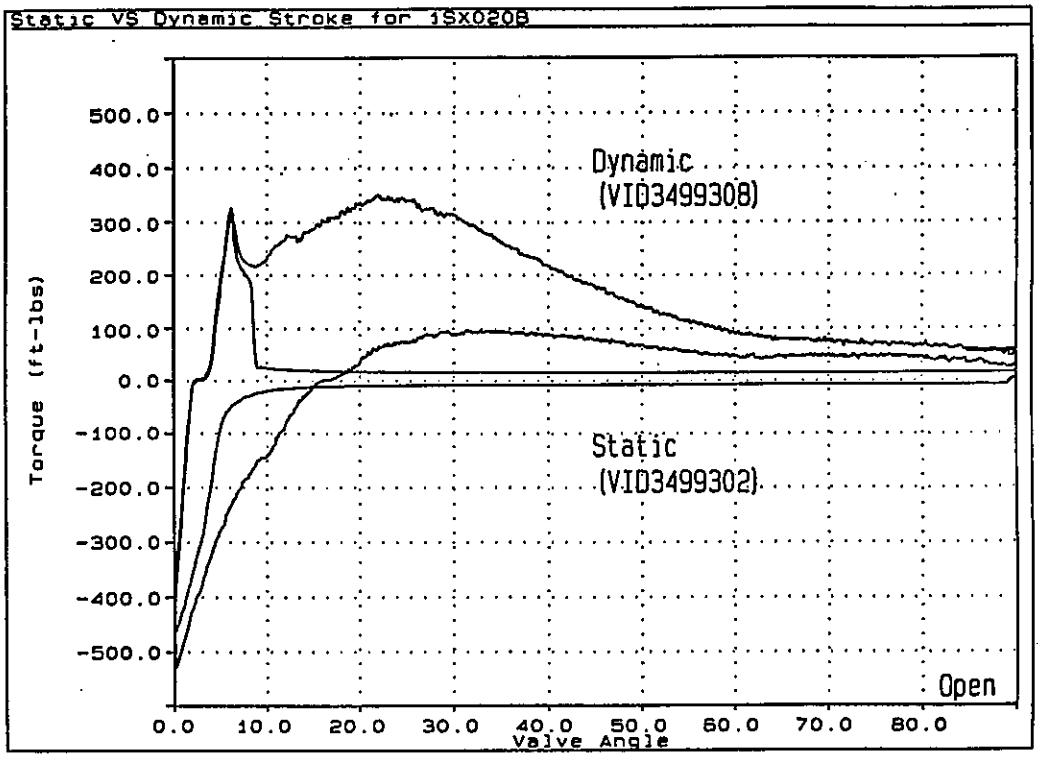

Figure C-2. Results for 1SX020B 12-in. MOV.

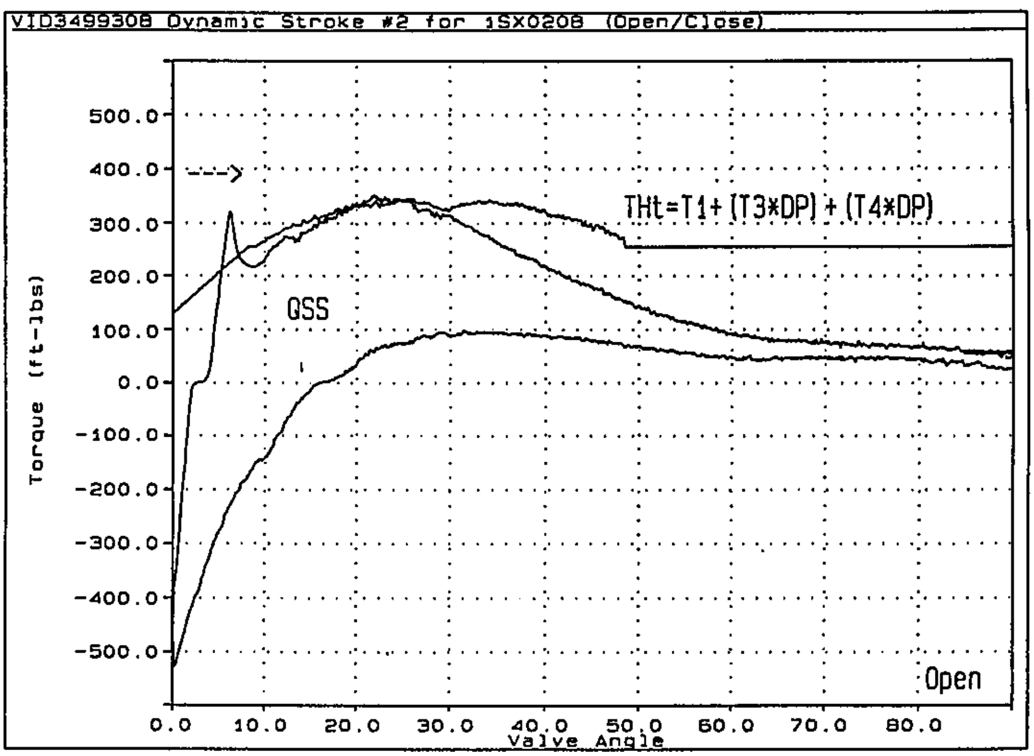

Figure C-3. Results for 1SX020B 12-in. MOV.

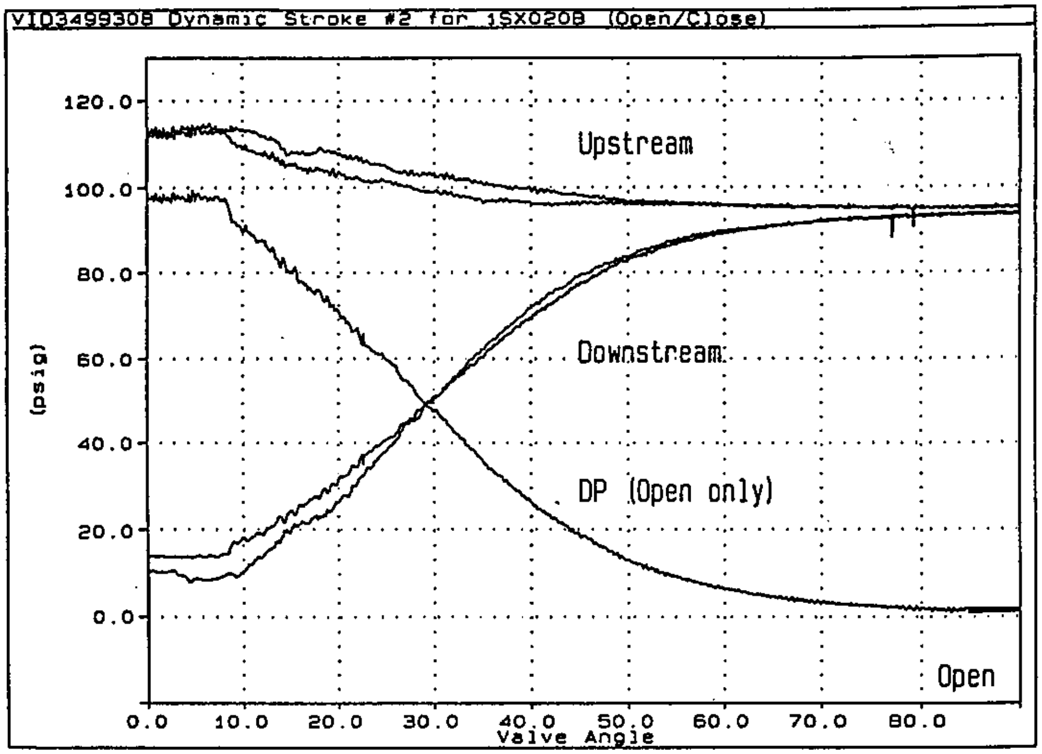

Figure C-4. Results for 1SX020B 12-in. MOV.

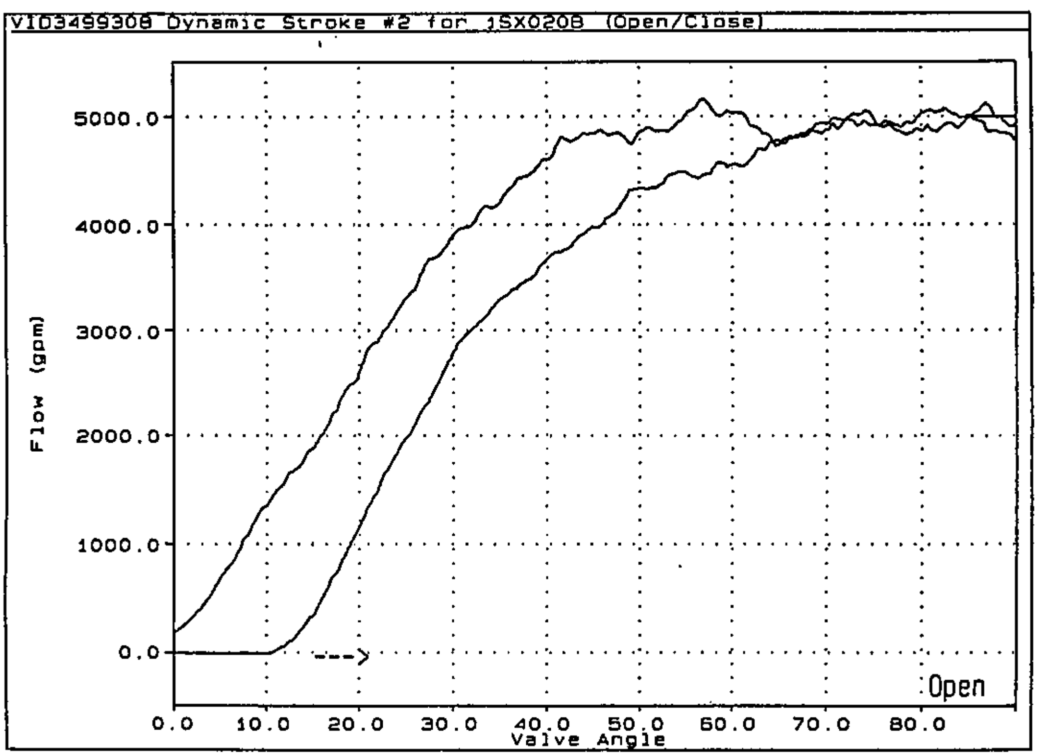

Figure C-5. Results for 1SX020B 12-in. MOV.

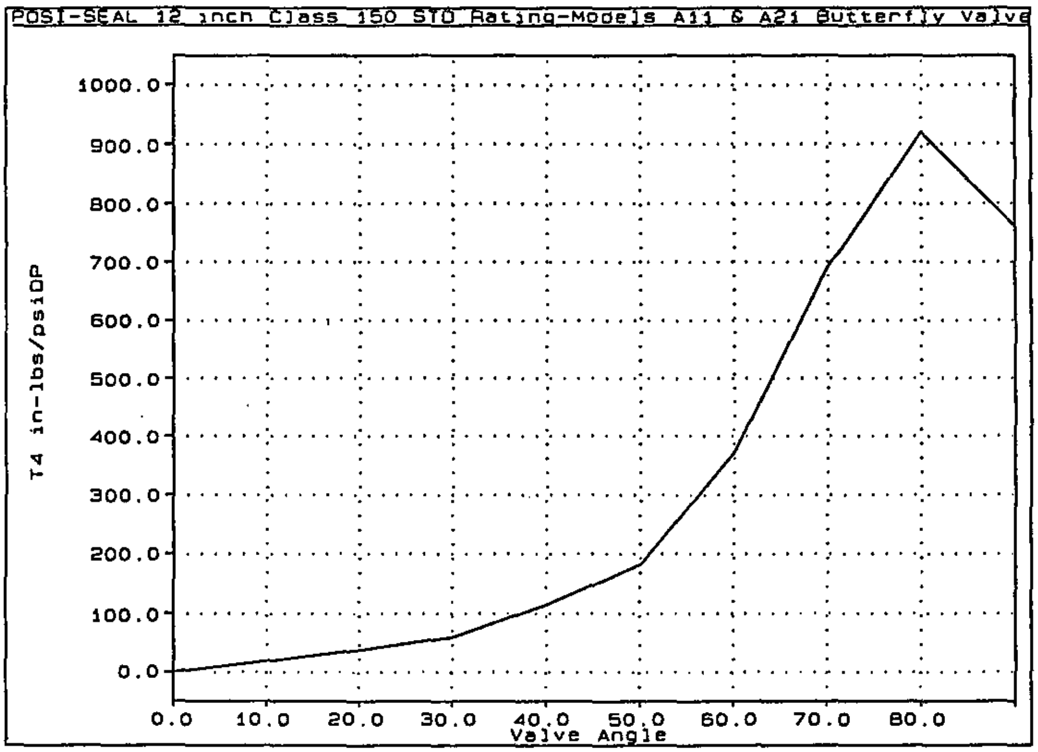

Figure C-6. Results for 1SX020B 12-in. MOV.

Results for 1FC026A 14-in. MOV

VALVE 1FC026A

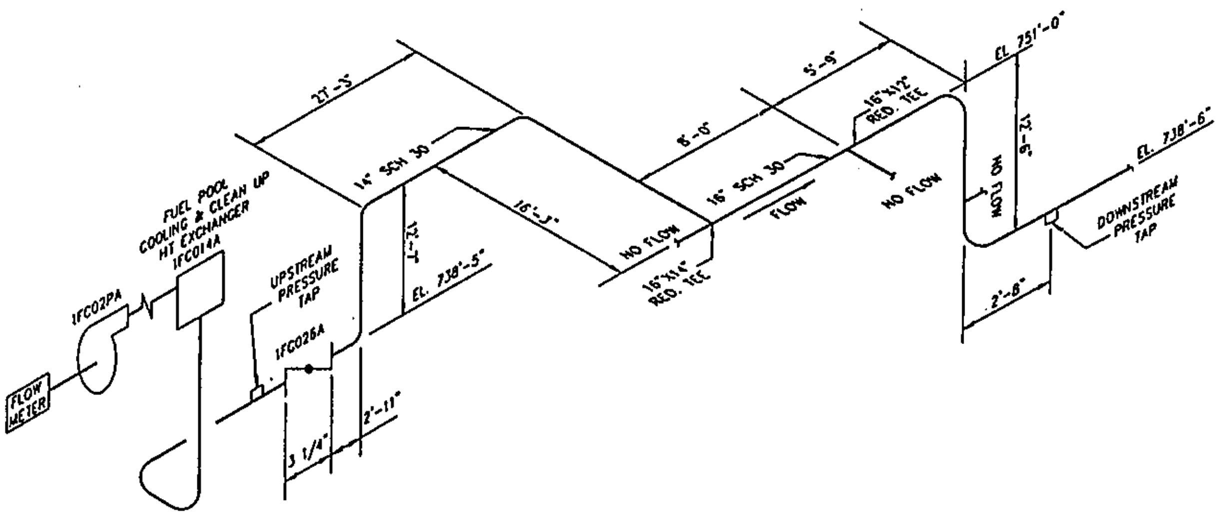

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Figure D-1. Results for 1FC026A 14-in. MOV.

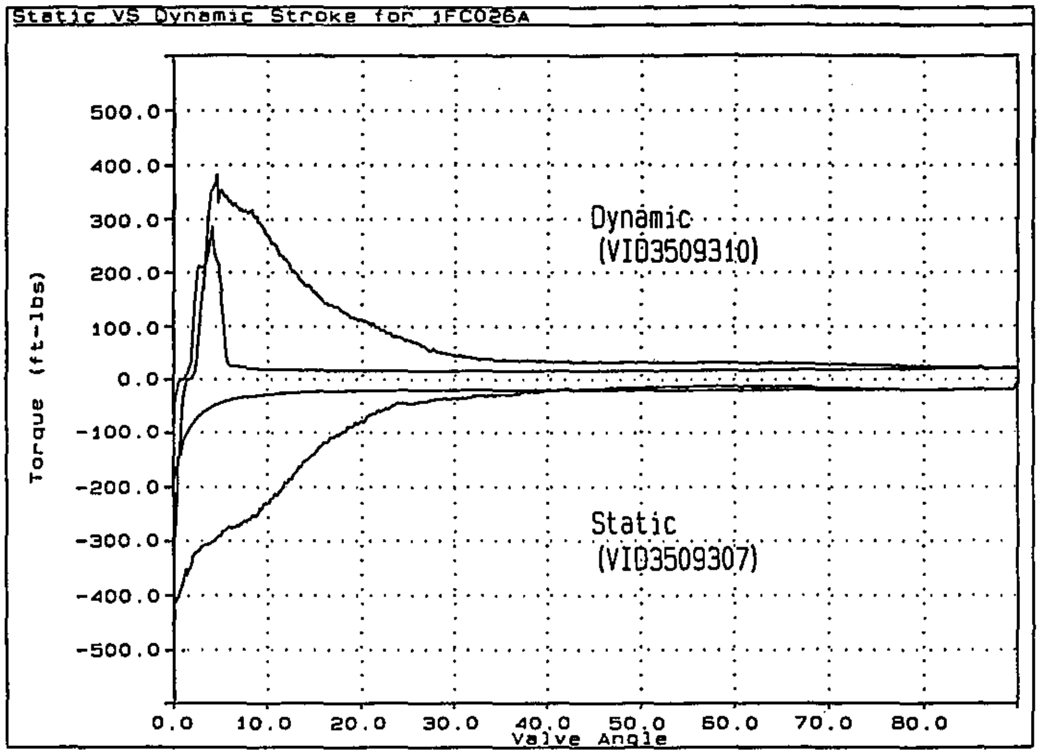

Figure D-2. Results for 1FC026A 14-in. MOV.

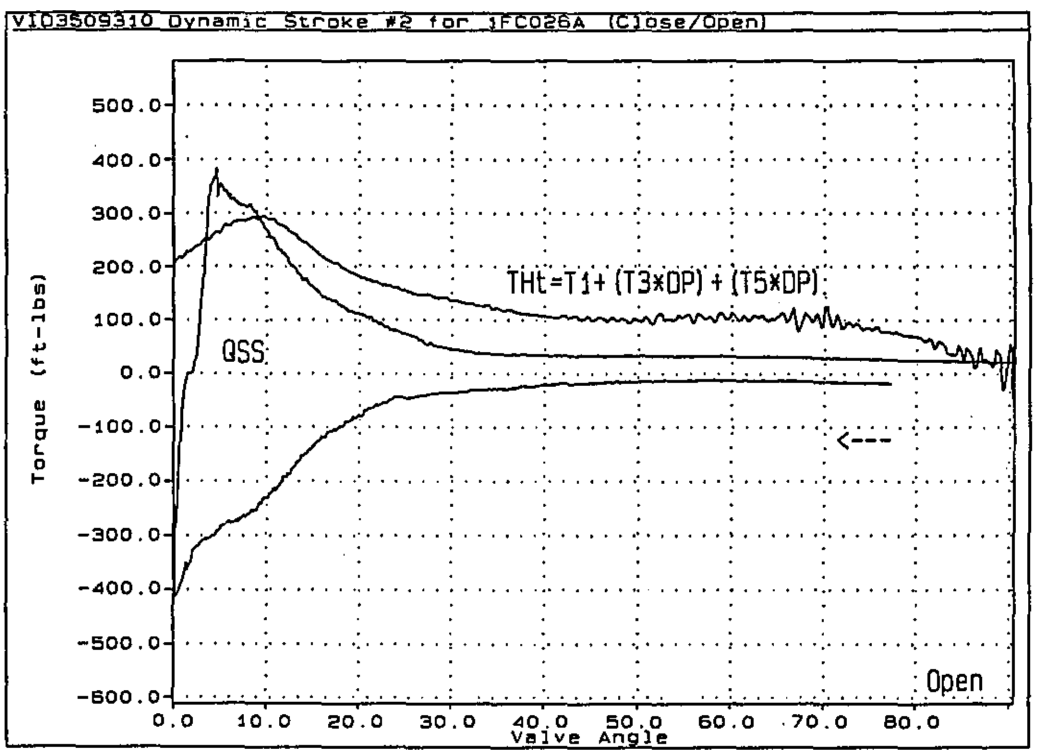

Figure D-3. Results for 1FC026A 14-in. MOV.

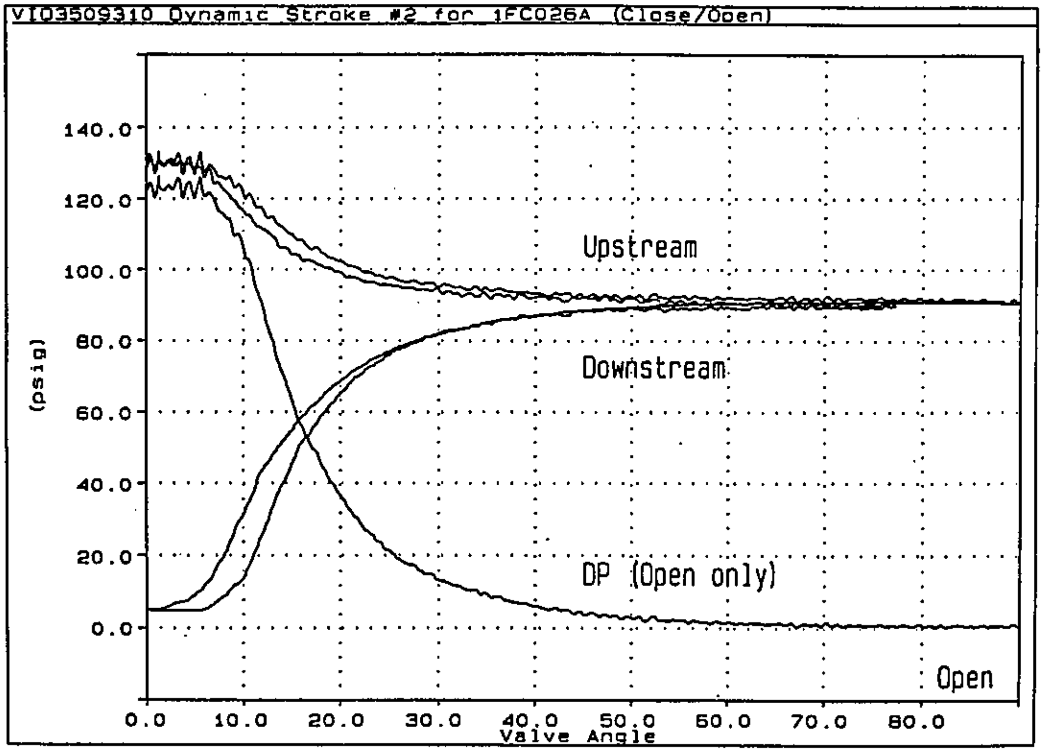

Figure D-4. Results for 1FC026A 14-in. MOV.

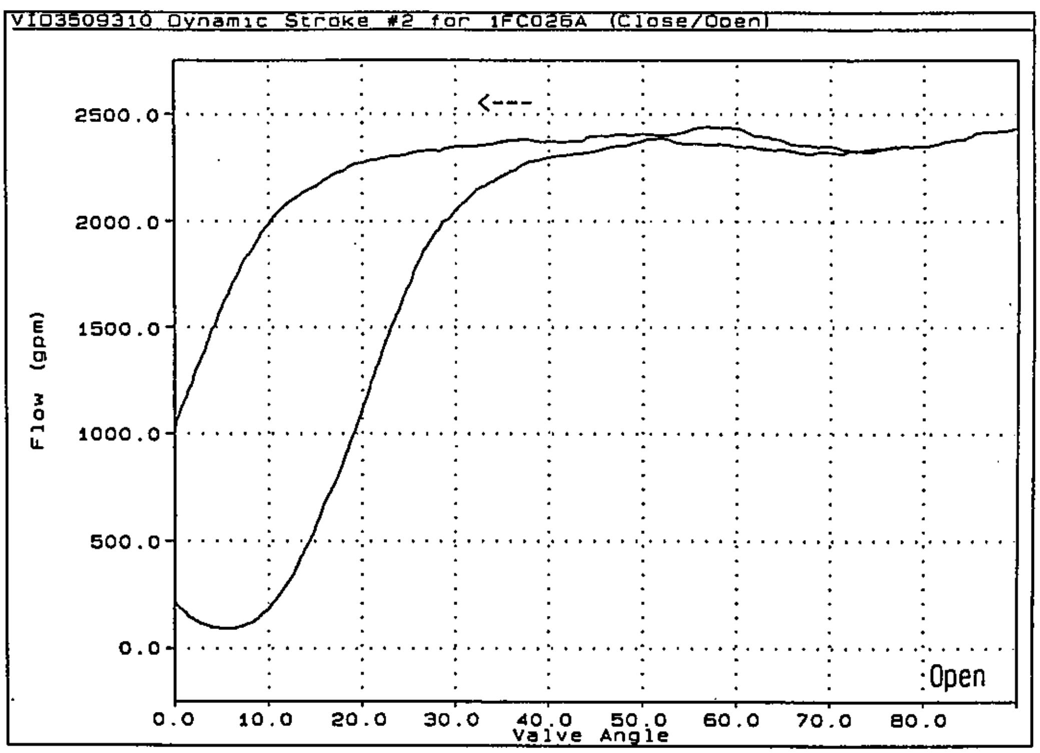

Figure D-5. Results for 1FC026A 14-in. MOV.

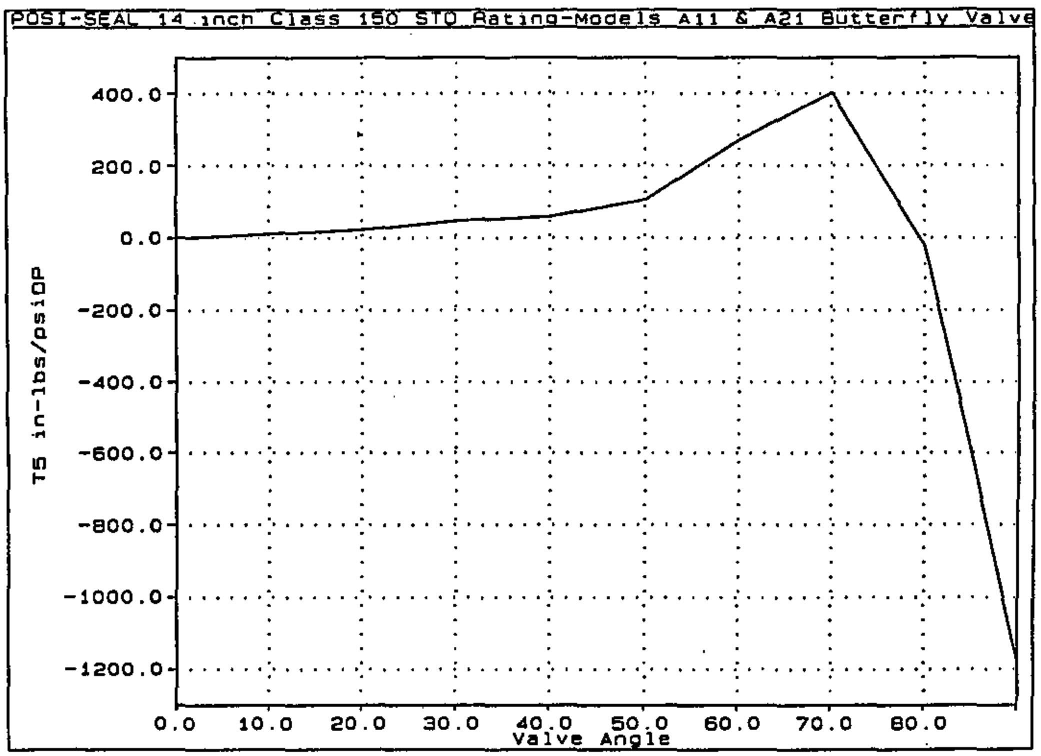

Figure D-6. Results for 1FC026A 14-in. MOV.

Results for 1FC026B 14-in. MOV

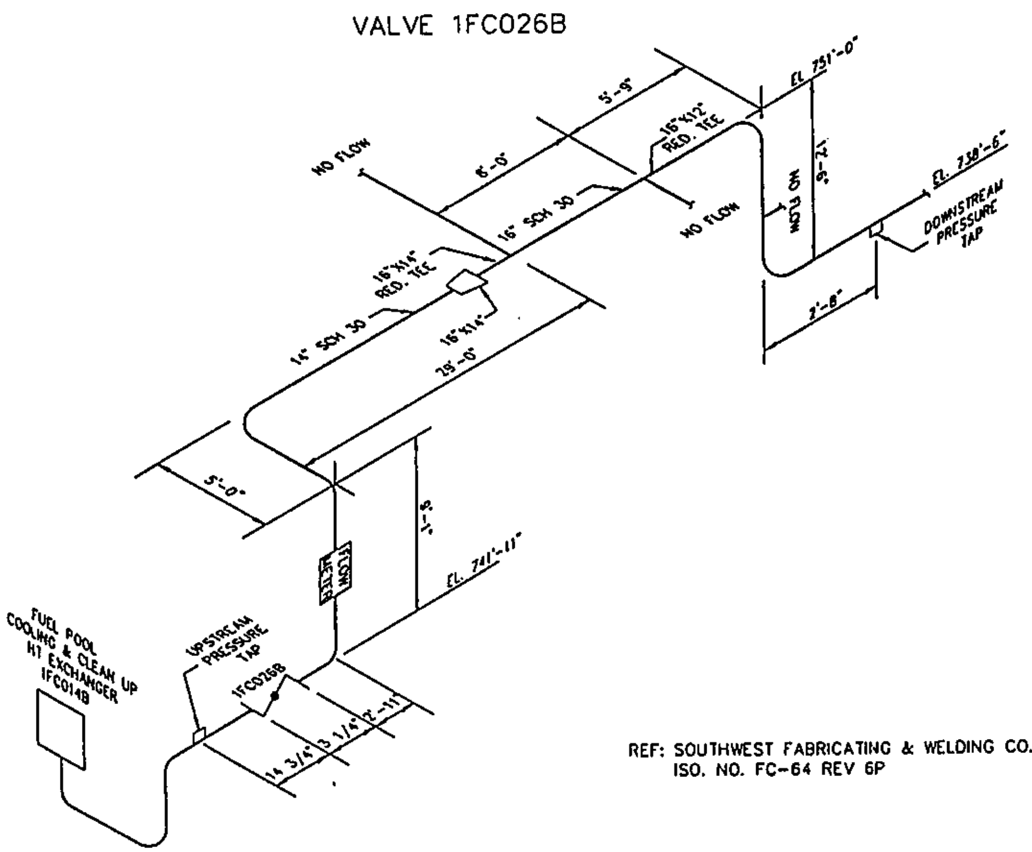

Figure E-1. Results for 1FC026B 14-in. MOV.

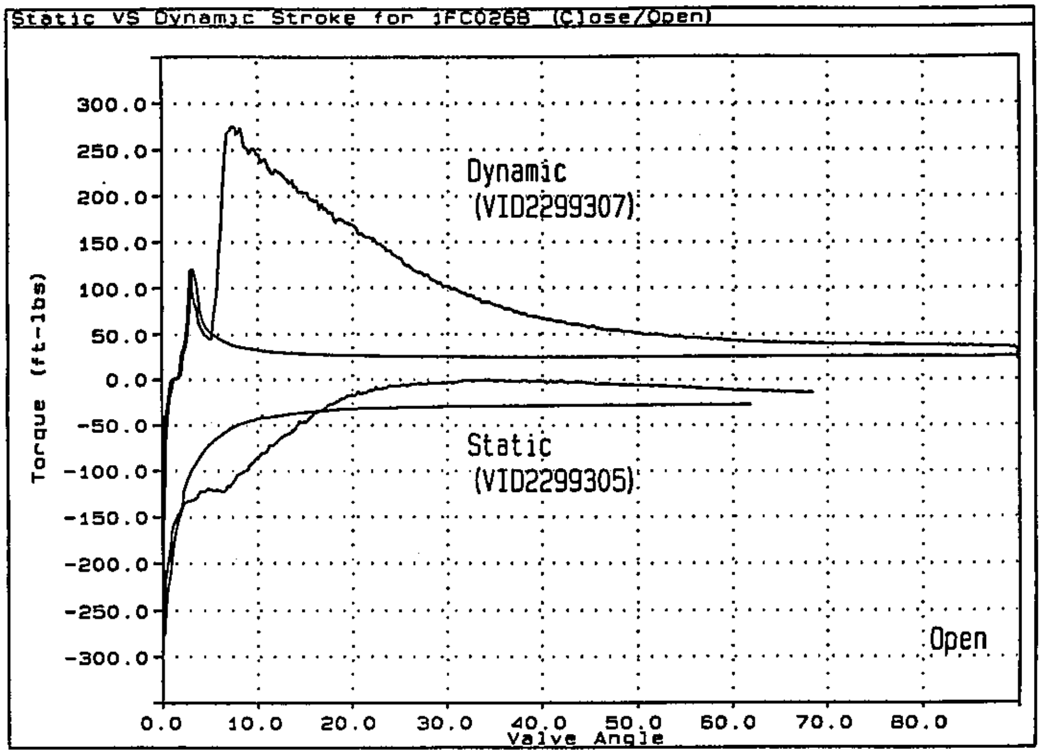

Figure E-2. Results for 1FC026B 14-in. MOV.

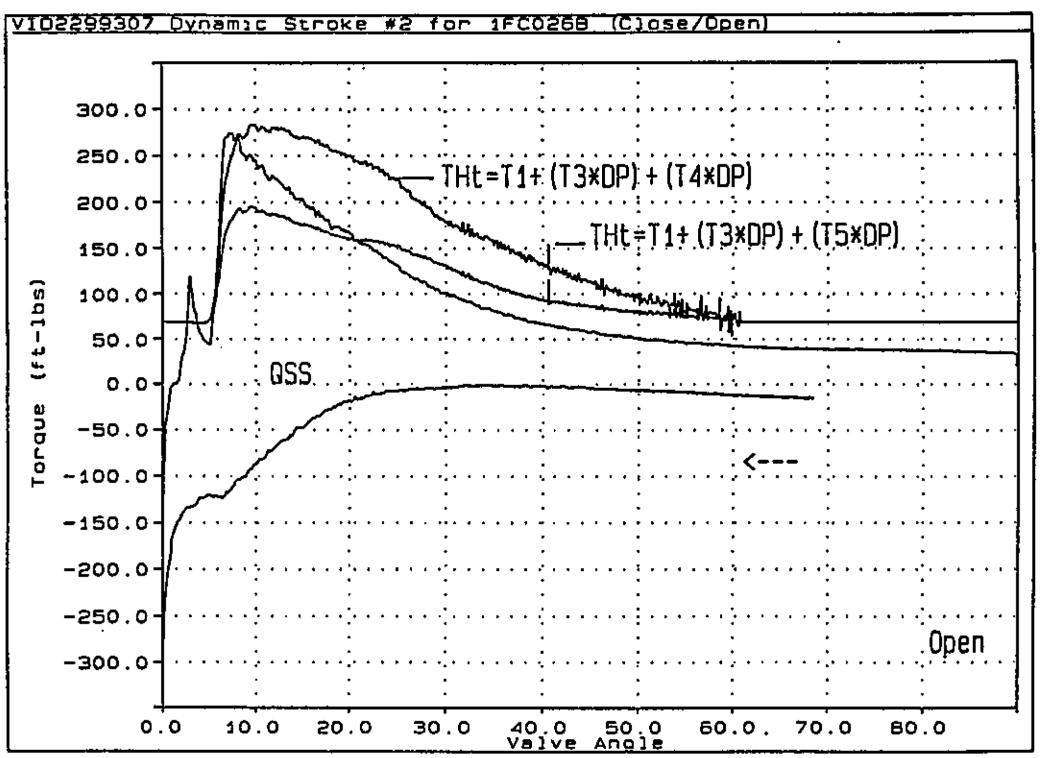

Figure E-3. Results for 1FC026B 14-in. MOV.

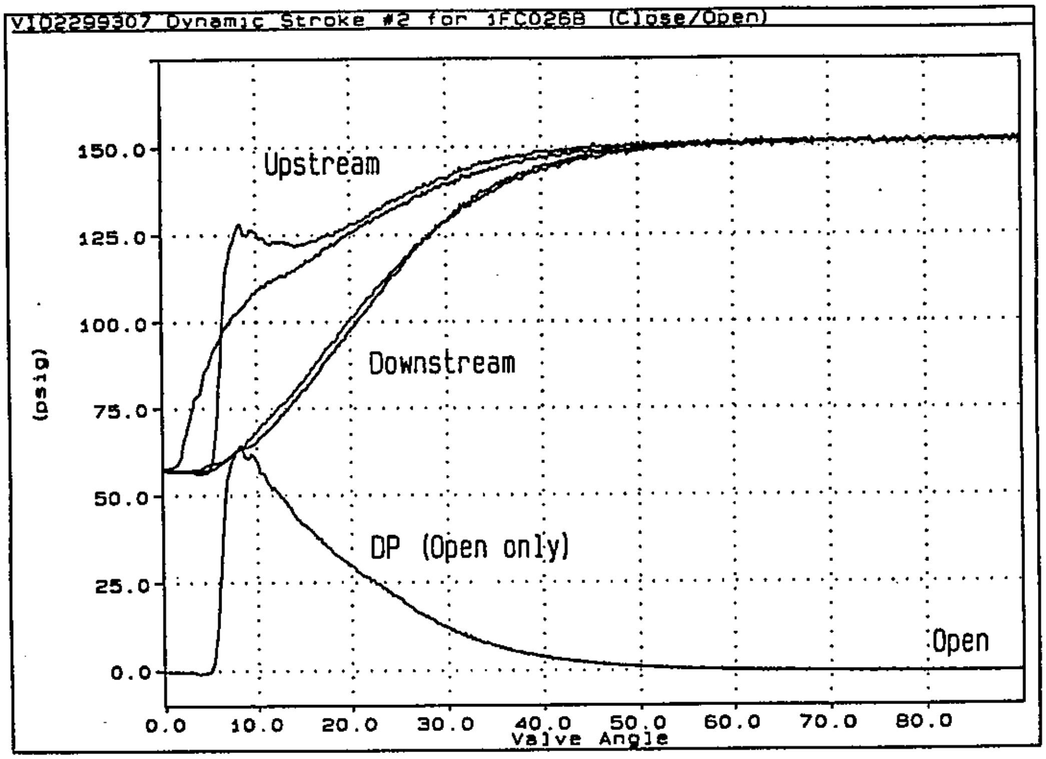

Figure E-4. Results for 1FC026B 14-in. MOV.

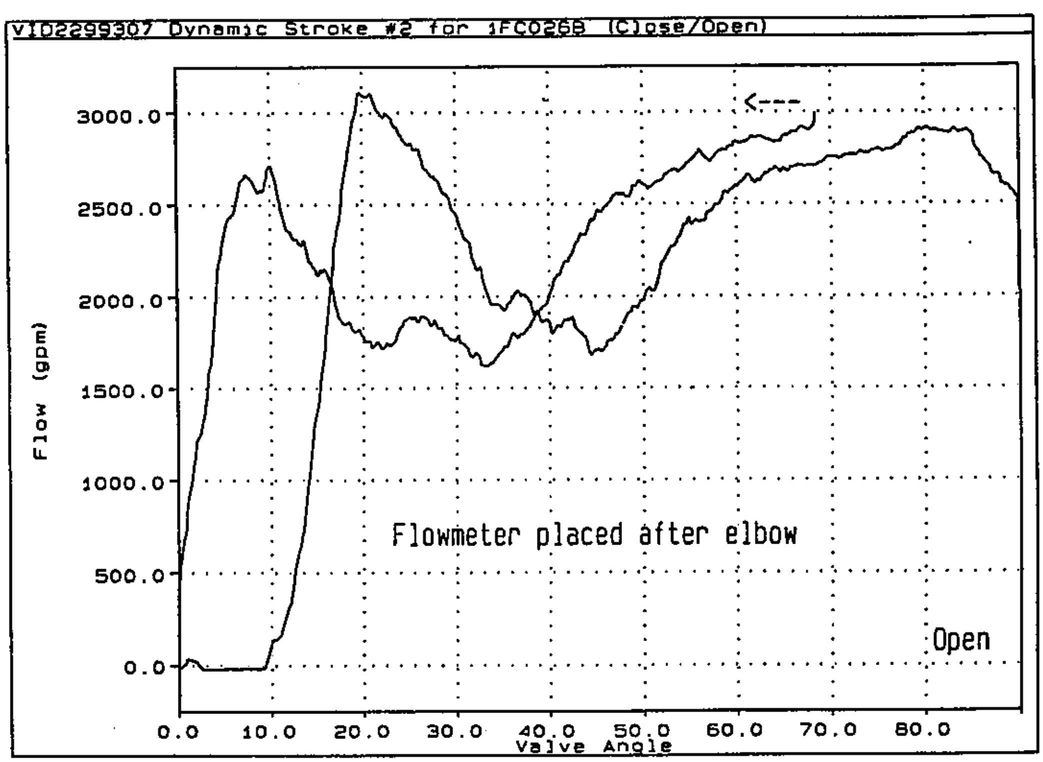

Figure E-5. Results for 1FC026B 14-in. MOV.

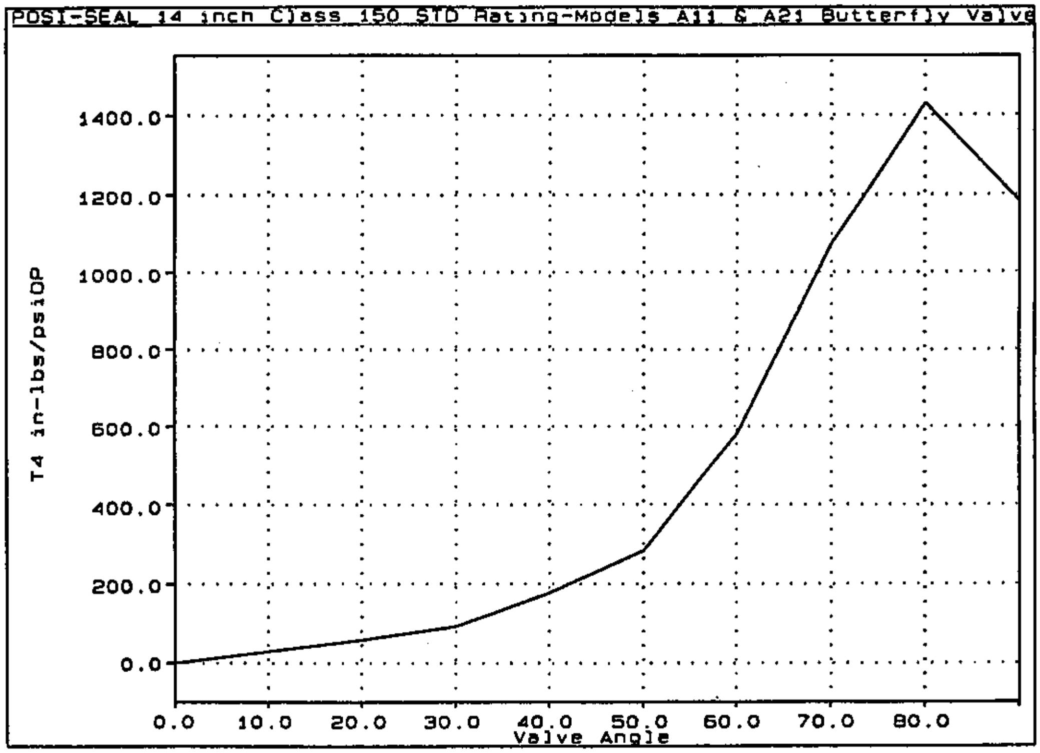

Figure E-6. Results for 1FC026B 14-in. MOV.

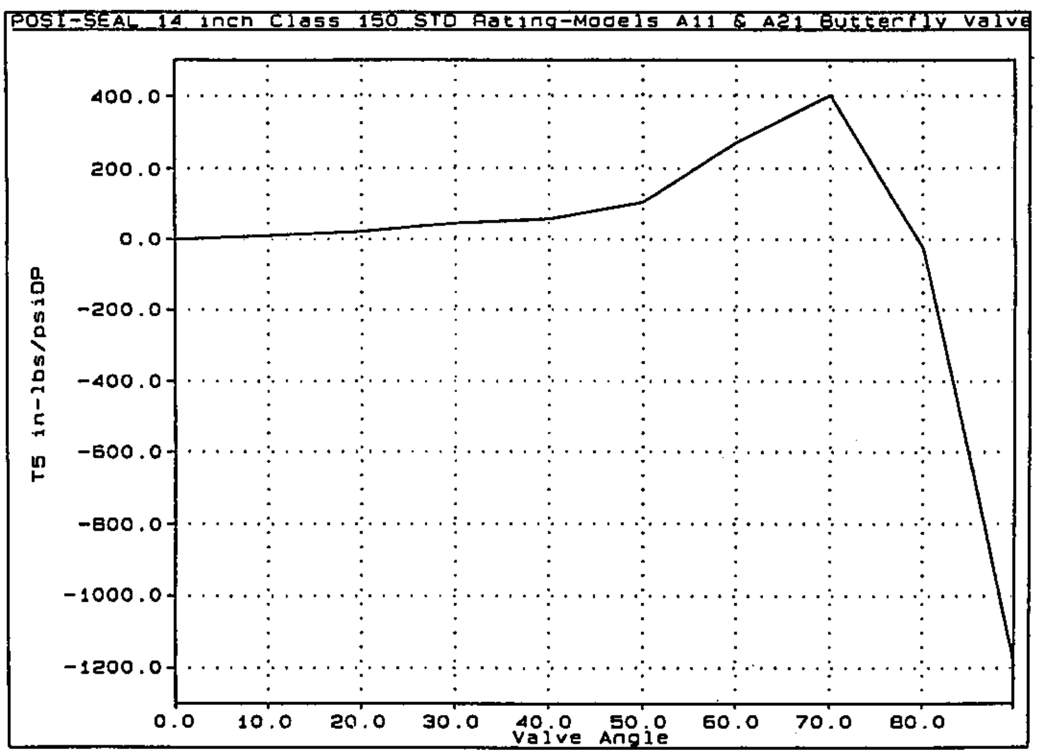

Figure E-7. Results for 1FC026B 14-in. MOV.

Results for 1SX014A 20-in. MOV

VALVE 1SX014A

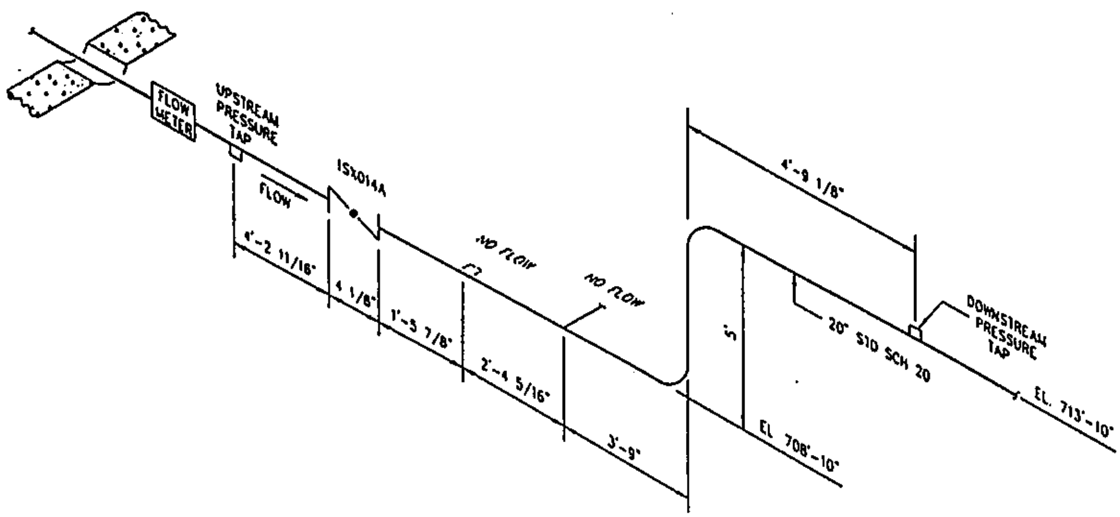

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Figure F-1. Results for 1SX014A 20-in. MOV.

No Static Stroke Available for Valve 1SX014A

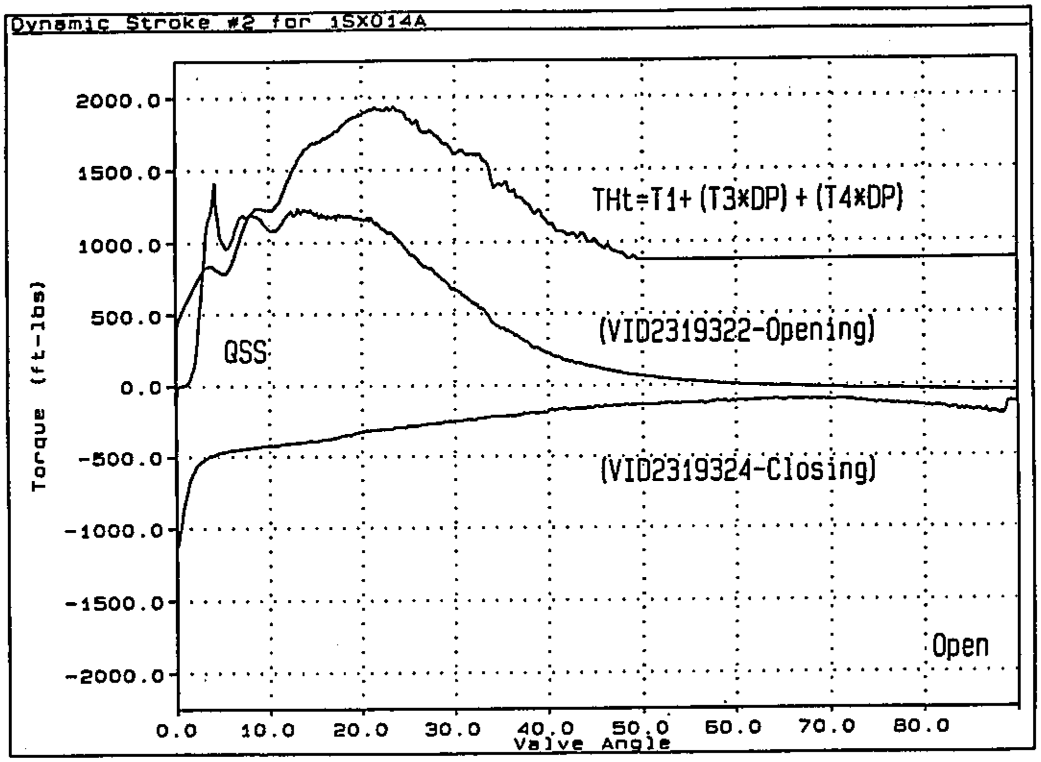

Figure G-1. Dynamic Stroke 2 for 1SX014A.

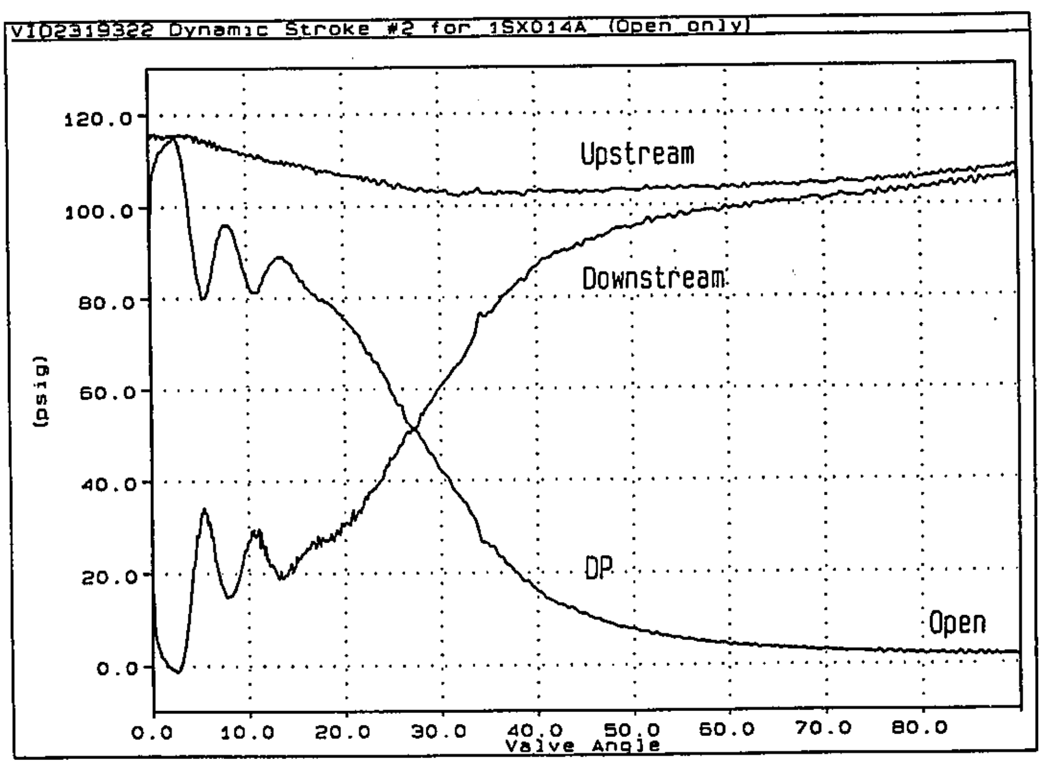

Figure G-2. VID2319322 dynamic Stroke 2 for 1SX014A (open only).

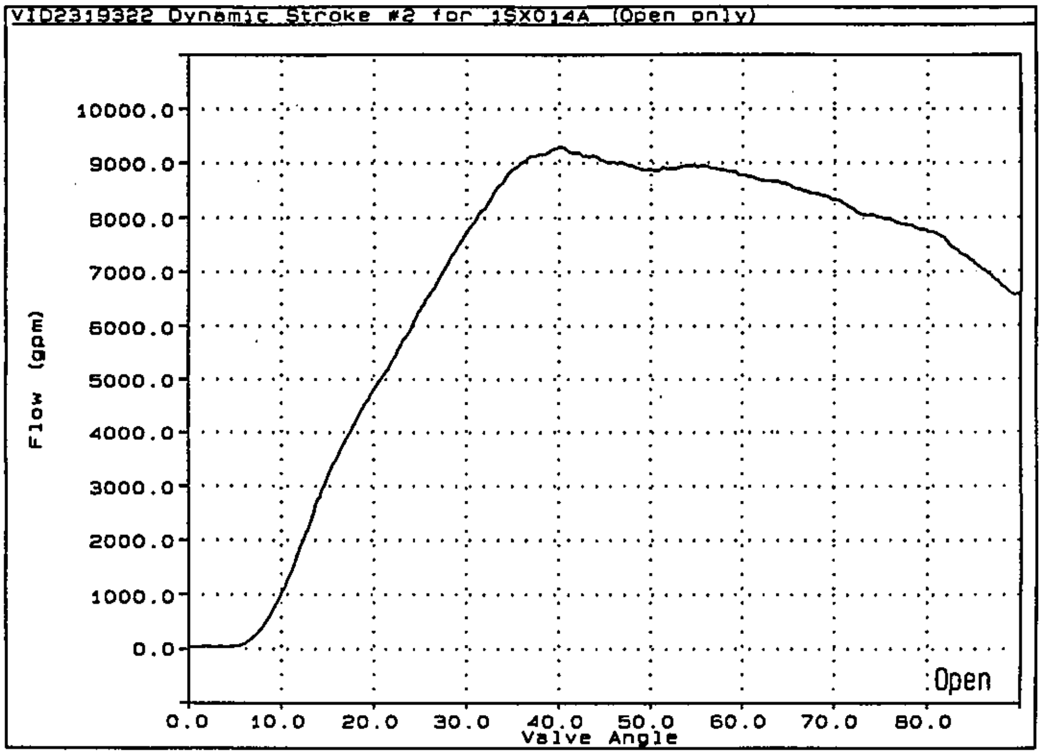

Figure G-3. VID2319322 dynamic Stroke 2 for 1SX014A (open only).

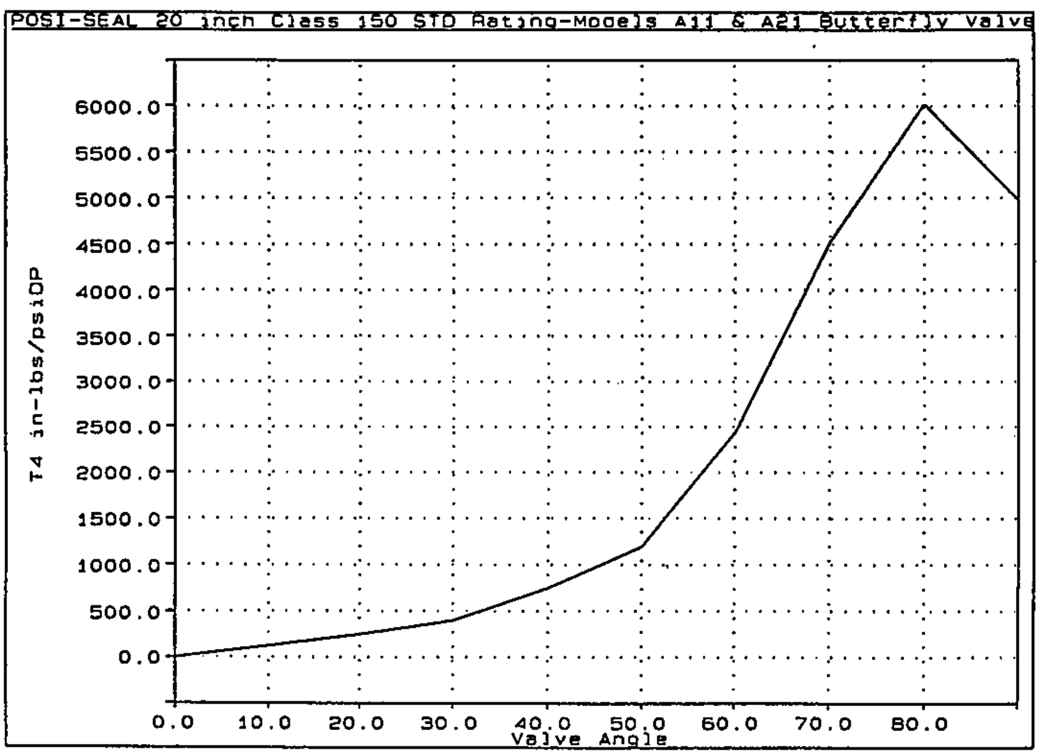

Figure G-4. POSI-SEAL 20 in. Class 150 STD rating-models A11 and A21 butterfly valve.

Periodic and Postmaintenance Testing of Motor-Operated Valves

Roger Carr
ITI MOVATS, Inc.

ABSTRACT

Motor-operated valve (MOV) testing programs have been developed and implemented by most utilities during the last 5 years. To date, most of the emphasis has been on baseline and design-basis testing. Programs for periodic and postmaintenance testing are being developed, but most rely on at-the-valve techniques for ascertaining valve condition. Methods that avoid sending test personnel to the valve save time and radiation exposure and may often be the only alternative when plant conditions preclude entry into the area containing the valve. This paper discusses the viability of various techniques used for periodic and postmaintenance testing and the direction that future testing may take.

INTRODUCTION

The most obvious remote location for monitoring motor-operated valve condition is the motor control center. Motor current, voltage, and control switch information are all available at the motor control center. Various techniques have been used to analyze these parameters, and the results used to diagnose both the valve and the actuator. Identification of anomalous behavior has been relatively straightforward using these techniques, but quantifying the effect on valve stem thrust has been complicated by uncertainties. The largest uncertainty is in the friction loss of the stem-to-stem-nut interface. Some approaches to using motor control center data make assumptions about behavior of the loading profile in an effort to deal with this uncertainty. The unpredictable behavior of motor operated valve actuators makes these assumptions tenuous given present day knowledge.

HISTORY

Diagnostic testing of motor-operated valves began at some utilities more than 10 years ago. The initial focus was on improving the maintenance condition of the valves and actuators to increase power production capability. Electronic signatures of key parameters such as spring pack displacement (compared to stem force), motor current, and switch position were monitored at the valve and analyzed to identify degrading conditions before they caused failures. Several industry events resulted in regulatory action that pushed diagnostic testing in the direction of verifying design capability. As a result, transducer development moved toward direct force measurements by monitoring torque and thrust as accurately as possible.

Significant interest in testing from the motor control center developed early in the MOV diagnostics era. In 1986, a method was proposed for correlating a motor power parameter such as input power or power factor to stem thrust (Charbonneau et al., 1989). The method involved monitoring the power parameter and stem thrust simultaneously during a calibration test and using the correlation for future tests. A hydraulic cylinder was used to simulate valve loads. The basic equation used to convert power parameters to thrust is:

$$\Delta TH_{OP} \approx \frac{\left(\frac{\Delta TH_{CAL}}{\Delta t_{TH}}\right)}{\left(\frac{\Delta P_{CAL}}{\Delta t_{P}}\right)} \Delta P_{OP} \qquad (10)$$

where

TH_{CAL}	=	stem thrust during a calibration valve stroke
P_{CAL}	=	power parameter during a calibration valve stroke
TH_{OP}	=	stem thrust during a post-calibration valve stroke
P_{OP}	=	power parameter during a post-calibration valve stroke
Δt_{TH}	=	time interval selected for monitoring the change in stem thrust
Δt_P	=	time interval selected for monitoring the change in power parameter.

Equation (1) assumes that the relationship between stem thrust and power remains constant over time. This equation is normally applied in an area of the signatures where the stem thrust is increasing on a stable ramp. The terms Δt_{TH} and $\Delta\ t_P$ typically represent the same time interval and, as a result, can be cancelled from the equation.

Two variations of this formula are shown below:

$$\Delta TH_{OP} \approx \frac{\frac{d}{dt}TH_{CAL}}{\frac{d}{dt}P_{CAL}}\ \Delta P_{OP} \qquad (11)$$

and

$$\Delta TH_{OP} \approx \frac{\frac{d}{dt}TH_{CAL}}{\frac{d}{dt}P_{OP}}\ \Delta P_{OP} \qquad (12)$$

All of these equations use the ratio of the slopes of the power and thrust versus time signatures as a constant of proportionality. Equations (2) and (3) use the derivative, but in practice the slope must be calculated over some time interval. Because the instantaneous slope varies considerably, a longer time interval is preferred. Equation (3) makes the additional assumption that the slope of the stem thrust signature is the same for the calibration test and for all subsequent tests over the interval selected for calculating the derivative. Equation (2) requires that the derivatives be taken at the same point in time and Equation (3) requires that they be taken at an equivalent point in time for the two tests.

From 1986 to 1991, various refinements were made to the correlation approach described above (Hale et al., 1989; Charbonneau et al., 1990; Charbonneau et al., 1991). A single-phase power monitor compensated for motor losses was introduced in 1986. Repeatability and accuracy of the power-to-thrust correlation from this device were affected by the rate at which load was applied, voltage variations and phase imbalance in the power supply to the motor, and current probe limitations. Efforts to deal with repeatability and accuracy led to the development of a three-phase meter that measured real power in 1991.

Beginning in 1988, several valve/actuator issues, coupled with nonlinear motor performance, challenged the feasibility of correlating motor power parameters to valve stem thrust. Stem factor variation with time was found to be substantial with certain types of lubricants, thread configurations, and environmental conditions. Stem factor was also found to vary with load rate or load history in an unpredictable manner. Actuator and motor efficiency variations were smaller, but also contributed to the problem. Bounding assumptions for these uncertainties were made, but these were often so large that the method could not be used unless the actuator output capability was substantially greater than that required to operate the valve under design conditions. As the emphasis moved toward accurate and direct measurements of torque and thrust, interest in motor control center (MCC) testing waned.

An alternate methodology for MCC testing was developed in 1986 at Oak Ridge National Laboratory (ORNL) (Haynes and Eissenberg, 1990). Motor current was collected and processed

in a way that provided substantial information from the frequency spectrum. Many actuator and valve degradations were apparent in the frequency spectrum, particularly those associated with rotating parts. As a result, this method provided a very effective tool for identifying mechanical changes. ORNL has continued to improve the basic approach to motor current signature analysis, providing clearer definition of spectral information. Use of this approach was limited because it did not provide the quantitative information necessary to ensure that actuator capability was sufficient to operate the valve when needed.

CURRENT STATUS

The bulk of industry MOV testing in response to NRC Generic Letter 89-10 has been completed, and plans for periodic and postmaintenance testing are being developed. In some cases, plants will continue to use direct measurements of torque and thrust at the valve for future testing. Although this approach will save the cost of purchasing new equipment, writing new procedures, and retraining personnel, it may result in higher testing cost and more radiation exposure. There is substantial renewed interest in testing from the MCC to avoid these problems. The question is, can the uncertainties that hindered MCC approaches in the past be overcome?

POSSIBILITIES

While MCC testing offers significant advantages in cost and radiation exposure, it cannot completely replace at-the-valve approaches, even if the uncertainty issues are resolved. Certain types of maintenance will make testing at the MCC impractical because some of the test personnel will have to be at the valve. One example is periodic replacement of actuator grease. This activity involves removing the actuator, disassembling it, removing the old grease from all the parts, replacing any worn or damaged parts, and reinstalling the actuator on the valve. When the actuator is reinstalled, the limit and torque switches must be set. Setting these switches using diagnostic equipment installed at the MCC would not make sense. Other types of postmaintenance testing would also be more effective if performed at the valve.

Sensors on the valve can be installed permanently or temporarily for the duration of the test. Permanent installation saves a significant amount of testing time, but the hardware cost is much higher. Durability and confirmation of calibration also become bigger issues for permanently installed hardware. An effective program will mix the two, using permanently installed sensors with high durability and accuracy for the small population of critical, low margin, hard to access valves and temporary transducers for the remaining majority. New transducer developments are moving toward quick installation that minimizes the need for removing the valve from service to perform testing. These devices should significantly reduce the test time advantage of permanently installed transducers while maintaining the cost advantage by not requiring individual sensors for each valve.

MCC testing can also be accomplished using permanently or temporarily installed equipment. Permanent installation can range from providing connections external to the MCC for attaching data collection equipment to online equipment that monitors motor and switch information continuously. Again, the cost of permanent installation must be weighed against the testing time and radiation dose saved. The data can be analyzed in the time domain, frequency domain, or both.

The time domain approach described in the previous section can be used to identify a wide variety of degradations, and the ability to estimate thrust capability by this method is becoming more feasible. In the past few years progress has been made in understanding and dealing with the uncertainties that plagued previous efforts to determine valve capability from the MCC. The Electric Power Research Institute (EPRI) MOV Performance Prediction Program has identified lubricants that minimize stem coefficient of friction variation with time. EPRI is also working on methods for predicting and bounding the variation with load rate or load history. Recent discoveries at the Idaho National Engineering

Laboratory show promise in this area as well. Motor models that deal with motor losses are being developed at ORNL that may further reduce the uncertainty associated with correlating MCC parameters to stem thrust.

While frequency domain analyses have focused primarily on qualitative results that identify degradations, research is being conducted on techniques to extract quantitative information. This work is still too early in the development process to speculate on its potential for success, but it may provide an alternative to, or independent confirmation of, results obtained from the time domain.

CONCLUSIONS

The primary conclusion is that effective post-maintenance testing programs will use a combination of MCC and at-the-valve testing techniques. As methods are further developed for dealing with uncertainties in MOV performance, this testing will shift in the direction of the MCC. Supporting conclusions are as follows:

1. MOV testing at the valve cannot be completely eliminated by MCC testing because some maintenance activities dictate that testing personnel be at the valve to set limit and torque switches.

2. The cost of installing and maintaining permanent transducers for testing MOVs must be weighed against the test time and radiation exposure saved.

3. Critical MOVs, MOVs that have capability that only slightly exceeds design requirements, and MOVs that are not easily accessible are good candidates for permanently installed sensors that are both durable and accurate.

4. MCC testing methodologies based on both frequency and time domain analysis techniques were developed in the mid-1980s, but the need for quantitative data coupled with growing concerns about unpredictable valve and actuator behavior prevented their widespread application.

5. Progress in understanding and dealing with uncertainties in MOV performance, such as variation in stem friction coefficient, may make the MCC time domain approach a very effective screening tool to determine whether more extensive, at-the-valve testing is warranted.

6. Frequency domain analysis provides an excellent tool for identifying MOV degradations and may provide quantitative information in the future.

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Efforts by the Nuclear Industry to Evaluate Check Valve Failures

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ABSTRACT

Check valves are critical components in the operation of current generation nuclear power plants, and may serve an increasingly critical role in the designs of future advanced light water reactors. Check valve failures can result in significant operating transients, increased costs, and/or decreased system availability. Increasingly, the tools and methodologies which the industry uses to improve performance, monitor deterioration, and indicate improvement are based on component failure data. It is essential that accessible, detailed failure data be made available to ensure that these methodologies are successful. Existing data must be reviewed, filtered, updated, and supplemented in order to provide the tools for successful implementation of proposed methodologies. Over the past several years the efforts of the U.S. Nuclear Regulatory Commission, Institute of Nuclear Power Operations, and the nuclear industry have laid a foundation and supplied the building blocks to establish a system to support these efforts. Combined with research efforts ongoing at Oak Ridge National Laboratory, this system could be available in part by the end of 1994, with the objective of providing an easily accessible failure/reliability database for check valves installed in safety-related nuclear applications.

INTRODUCTION

Check valves are critical components in the operation of nuclear power plants today and may serve an increasingly critical role in the designs of future advanced light water reactors (ALWRs). Check valve failures can result in significant operating transients, increased costs, and decreased system availability. Increasingly, the tools and methodologies that the industry uses to improve performance, monitor deterioration, and indicate improvement are based on component failure data. Such methodologies include the "maintenance rule" (10 CFR 50.65), which seeks to allow the industry to focus resources on problem areas based on system/component failure/availability indicators, "condition monitoring," a mechanism that uses the best available information to determine the most appropriate means of monitoring component operating condition, and probabilistic risk assessments (PRAs). Although existing failure data are available (with significant effort), they often fail to provide sufficient information for the check valve engineer to make educated decisions regarding his or her own applications. Most utilities have check valve engineers who possess an in-depth knowledge of the specific components at their facilities, but have limited knowledge of overall industry data

available to address check valve issues. This makes it difficult for the engineer to take advantage of industry gains in the check valve arena and apply them to his or her facility.

It is essential that accessible, detailed failure data be made available to ensure that these methodologies are successful. Existing data must be reviewed, filtered, updated, and supplemented in order to provide the tools for successful implementation of proposed methodologies. Over the past several years the efforts of the U.S. Nuclear Regulatory Commission (USNRC), Institute of Nuclear Power Operations (INPO), and the nuclear industry have laid a foundation and supplied the building blocks to establish a system to support these efforts. This system could be available in part by the end of 1994.

Recent studies (ORNL, 1993)[a] identified approximately 4,000 check valve failures that occurred from 1984–1991. Of these, approximately 1,600 were determined to be significant enough to require further analysis. These numbers are to be compared with the existing check valve population of nearly 21,000 valves. The strategy proposed in this paper is to establish a refined, centralized check valve failure/reliability database based in part on existing INPO Nuclear Plant Reliability Data System (NPRDS) data. Ideally, the database would be maintained in a central location, augmented with specific component information and overall reliability information and updated at least biannually. The conceptual plan is depicted in Figure 1. Two key features required to maintain the database are

- Independent reviewing/coding of new failures as they occur (biannually)
- Refining or adding data based on detailed reviews of the failures and linking of the failure data with other data sources, such as vendor design information and maintenance recommendations.

The data would be available to sort and search as desired. Possible uses of the database would be to

- Provide support for individual valve applications, analyses, and calculations
- Provide supporting evidence for maintenance and condition monitoring programs
- Support American Society of Mechanical Engineers (ASME) Code development work
- Provide detailed reliability data for future applications (e.g., ALWR designs)
- Provide feedback to valve manufacturers on operating problems and failures.

HISTORICAL EFFORTS

Uncoordinated reviews of check valve failures have been undertaken by numerous industry organizations and utilities over the past decade. Before to recent research (ORNL, 1993) performed by Oak Ridge National Laboratory (ORNL), one of the most recognized studies was by M. L. Scott (1989). Scott reviewed NPRDS failure records for events occurring during the years 1985–1987. Events involving moderate seat leakage and external leakage were excluded from the study, and the remaining events analyzed. This study was originally slated for use by the ASME Committee on Operation and Maintenance (OM) of Nuclear Power Plants Working Group on Performance Testing of Check Valves in Light Water Reactor Power Plants (OM-22) as a basis for developing check valve performance test requirements. Although some questions later arose regarding the validity of the conclusions from the study, this study is recognized as the first to address the historical failure analysis needed in code development activities.

a. Oak Ridge National Laboratory, *A Characterization of Check Valve Degradation and Failure Experience in the Nuclear Power Industry, 1991 Update*, Draft Report.

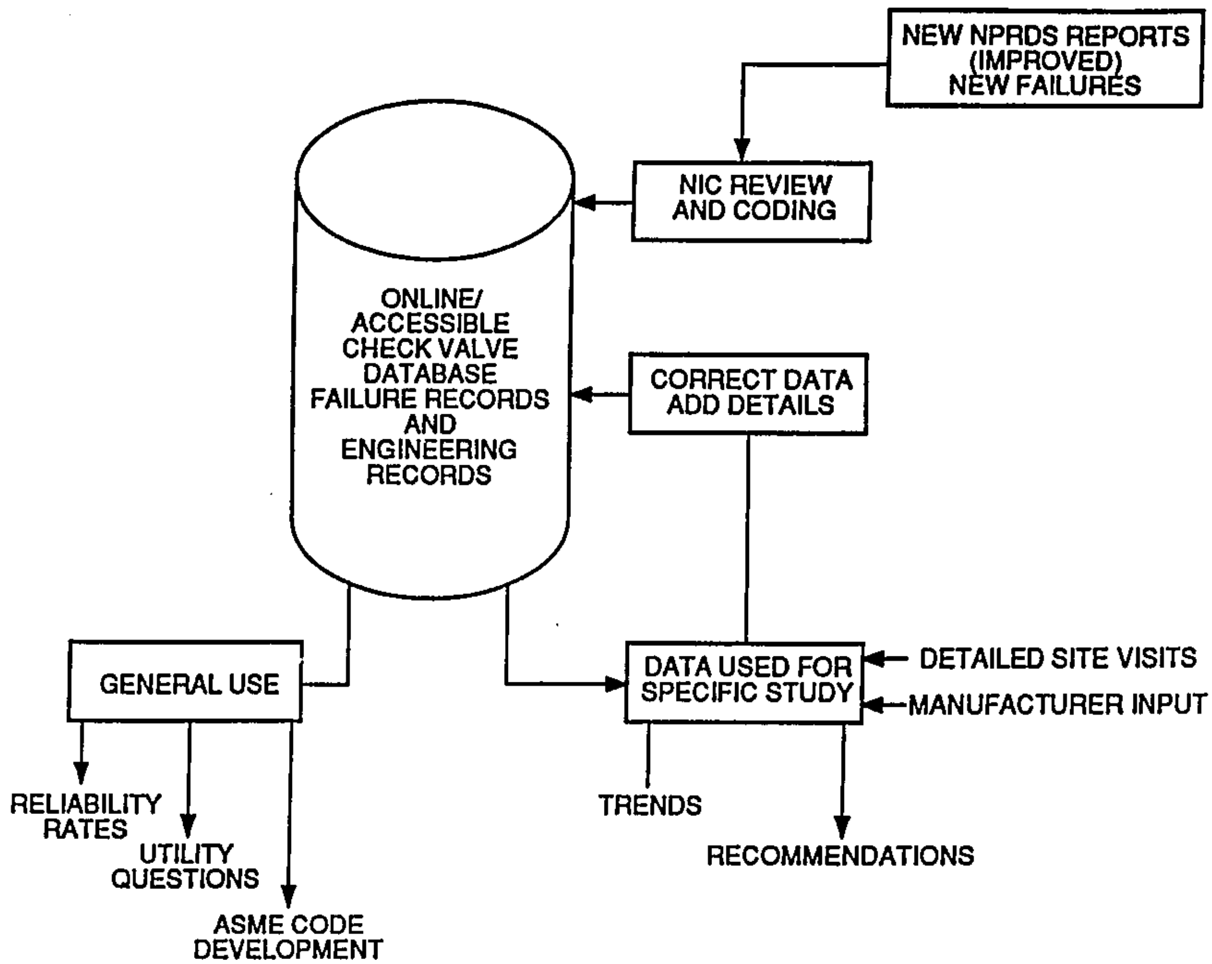


Figure 1. Check valve failure database concept.

Significant check valve failures occurring in the mid 1980s resulted in issue of the Significant Operating Experience Report (SOER) 86-03, "Check Valve Failures or Degradation" (INPO, 1986). To address the discovery of deficient conditions pertaining to check valves, the USNRC issued several notices, including Generic Letter 87-06, "Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves," (USNRC, 1987). Information Notice 88-70, "Check Valve Inservice Testing Program Deficiencies" (USNRC, 1988) and Generic Letter 89-04, "Guidance on Developing Acceptable Inservice Testing Programs." (USNRC, 1989) NUREG-1352, "Action Plans for Motor-Operated Valves and Check Valves" (Scarbrough, 1990) was issued in June 1990. The activities outlined in this document included a discussion of check valve problems and performance, evaluation of adequacy of regulatory requirements, development of inspection guidance, research, cooperation with industry groups, development of codes and standards, and evaluation of the USNRC staff and industry efforts. The USNRC also initiated a utility inspection program intended to evaluate check valve activities at each nuclear power plant.

In response to SOER 86-03 (INPO, 1986), the Electric Power Research Institute (EPRI) reviewed the application and failure history of

check valves, and published *Application Guidelines for Check Valves in Nuclear Power Plants* (EPRI, 1990). Their objective was to provide the utilities with assistance in the areas of check valve applications, maintenance, and diagnostic techniques, and to provide technical guidance for preventing premature valve failure and assessing long-term reliability.

With the exception of the EPRI work which was revised in 1993 (MacDonald, 1993), none of the early efforts related to check valve reliability retained a measure of continuity. Each group independently evaluated the available failure data, analyzed it, and came to their own conclusions. Until the initiation of the ORNL study in 1992, no effort was undertaken to perform a comprehensive and consistent analysis of check valve failure data. During the OM-22 Working Group's consideration of the Scott paper and its application to code development, some concerns arose about the technical validity of the Working Group's application of the study. As a result, ORNL was requested to conduct a preliminary review of failure data. Results of the preliminary review substantiated concerns about the use of the Working Group's basis study conclusions for use in code development activities. Accordingly, the USNRC commissioned ORNL to conduct a more thorough assessment of the historical failure data.

A Characterization of Check Valve Degradation and Failure Experience in the Nuclear Power Industry (ORNL, 1993) documents ORNL's evaluation of check valve failure data from 1984 through 1990. In addition to the report itself, a significant product from this effort was the failure database developed by reviewing the available NPRDS data, eliminating insignificant failures (i.e., those not involving internals degradation or those exhibiting only very minor seat leakage), and characterizing the remaining records according to failure mode, extent of degradation, detection method, and failure area. What resulted was a refined, usable database that may become the foundation for the proposed centralized failure/reliability database.

Attention may now be given to the process used to develop this database and the related efforts that are evolving within the nuclear industry to support continued efforts to expand this work.

FOUNDATION FOR A CHECK VALVE DATABASE

Commitment of USNRC and Nuclear Industry to the Effort

Support for the original ORNL evaluation of 1984–1990 failure data was provided by the USNRC's Nuclear Plant Aging Research Program. Recognizing the need for a thorough assessment of check valve historical failure data, the USNRC has committed to continue its support to ORNL to conduct updates on failure data for 1991 and 1992.

The Nuclear Industry Check Valve Group (NIC) has provided a focal point for the nuclear industry to become active in the failure data analysis. NIC's members have provided thoughtful review of the study methodology and failure characterizations, and have supplied additional information on failures not clearly explained in the NPRDS narratives. NIC cooperated with ORNL by providing detailed peer review of the data review process, as well as by validating the process with utility site visits. The site validation process involved seven nuclear plants (12 units) in which site personnel used related maintenance work order packages and their knowledge of the failures to review the ORNL characterization of the NPRDS data. The conclusion of this validation process was that the ORNL study provided a fair and accurate assessment of the failures. Two limitations of the characterization process became apparent during the validation: (a) the accuracy of the characterizations was dependent on the accuracy and thoroughness of the narratives, and (b) the reviewer must correctly interpret the narratives. Although it was noted that utilities had substantially improved the length and quality of narratives submitted to NPRDS during recent years, it would greatly enhance the accuracy and ease of use of the database if a

means were provided to directly code in parameters, such as the type of check valve and the affected (failure) area of the valve. Alternatively, if utility personnel responsible for submitting the failure records were made aware of the need to include such information in the narratives, the information could be obtained indirectly. Even though this approach would add to the effort required to evaluate the failure data, it would make the information available without modifying NPRDS.

Improvements to NPRDS Coding Practices

Over the past several years, a significant improvement has been noted in NPRDS failure reporting because both INPO and the utilities have increased attention on the details reported within NPRDS. NPRDS reporting rules have been modified to eliminate requirements for reporting minor external leakage and also to require improvements in reporting practices. These changes should facilitate future attempts to retrieve and analyze failure data, since the initial filtering process necessary in past efforts should be performed at the plant level in the future. Also, improved reporting practices (i.e., narratives that more fully explain each failure, its root cause, failure area, and corrective action, as well as increased attention given to providing correct information in the engineering record) should eliminate the time consuming process of contacting plant personnel to request additional information.

Additional Failure Data Review Efforts

Continuing the NRC commitment to this work, NIC formed a subcommittee in 1992 for "Industry Data Review." This subcommittee is undertaking detailed investigations on specific failure modes and systems identified in the ORNL analysis that exhibited high failure rates. NIC has already completed an in-depth study of failures with a "stuck closed" failure mode (see Appendix A) and plans to initiate data reviews on other specific cases.

Ongoing Efforts (1991 NPRDS Failure Data Analysis)

In an effort to continue their initial work, ORNL began a review of the 1991 NPRDS check valve failure data in June 1993. During the summer NIC meeting of that year, a revised methodology was developed for the 1991 study based on lessons learned from the original ORNL review of 1984–1990 data, the site validation effort, and a desire to support current issues being raised by the OM-22 Working Group. In order to acquire additional information not available in NPRDS records, the NIC subcommittee on Industry Data Review formulated a questionnaire to be sent to each affected site. Information requested on the questionnaire included specific valve type, special design features, configuration, application, inclusion in site check valve program(s), and other design data intended for NIC use only. Questionnaires were mailed out in August, and follow-up phone calls were made in October and December. Approximately 61% of the plants responded to the survey. Some information requested but not received was obtained through vendor catalog and EPRI check valve database reviews. Improved NPRDS failure narratives and questionnaire results provided a means for significant improvement of the failure database for 1991, and it is hoped that this type of information can be obtained for the already existing 1984–1990 database and the proposed centralized failure/reliability database. Figure 2 illustrates the process used to perform the 1991 analysis, and Appendix B discusses the preliminary results.

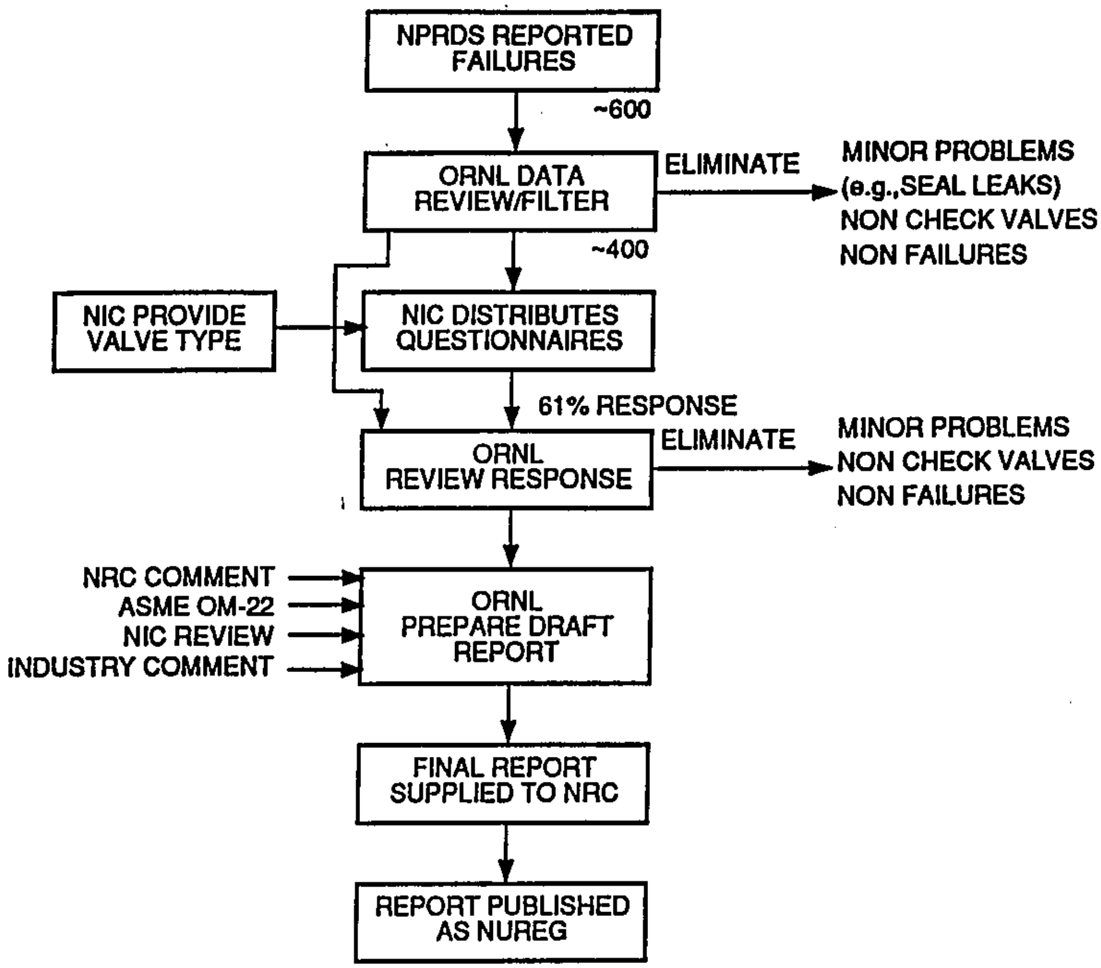


Figure 2. Check valve failure data review process for 1991.

VISION FOR A CHECK VALVE DATABASE

Lessons Learned

Both historical and current efforts have identified deficiencies in failure reporting requirements and practices. The following specific weaknesses have been discovered from working with data available from NPRDS:

1. The specific type of check valve (e.g., swing, lift, tilting disc) is not captured in either the NPRDS engineering record or the failure report.

2. Failure narratives often omit specific details concerning root cause, affected valve area, application, discovery method, failure mode, and corrective action.

3. Program status is difficult to determine (e.g., inservice testing, SOER 86-03, preventive maintenance program).

Because past analysis attempts have been hindered by lack of information such as specific valve type, these fields were added to the questionnaire sent to affected utilities for the 1991 data. Most of the information requested on the 1991 questionnaire is as yet unavailable for the 1984–1990 data and the overall valve population; however, it is anticipated that the procedure developed by NIC in conjunction with EPRI to

gather data (e.g., specific valve type) for those plants not responding to the 1991 questionnaire can be used to address these deficiencies. This process normally involves the use of the NPRDS fields of manufacturer name, manufacturer model number, model ID, size, and drawing number to identify the specific valve type from manufacturer catalogs and the EPRI check valve database.

Future Efforts

Specific Case Reviews. It has been demonstrated that full benefit can be obtained from the existing failure database by undertaking specific case reviews, such as the "stuck closed" failure mode review. NIC plans to continue specific data reviews concurrently with the annual NPRDS data review updates so that results obtained may be incorporated into the annual reports. It is anticipated that the results of such reviews may be of direct and immediate use to the nuclear industry, and will enhance the overall usefulness of the failure data analysis. As these benefits become apparent to utilities, the increased emphasis at the site level will be placed on ensuring that the information needed to perform the detailed case reviews is input into NPRDS at the time of the failure. NIC currently has plans to initiate specific case reviews on check valve failures in diesel starting air systems as well as those where the valve disc or other parts have broken or become detached.

NPRDS Data Review Updates. Tentative schedules for future NPRDS failure data updates were developed at the Winter 1993 NIC meeting. The schedules for these reviews are listed below:

1991 NPRDS DATA REVIEW

February 1994	Utility questionnaires complete
May 1994	Data compiled; draft report available
June 1994	Industry review of draft report at Summer NIC meeting
December 1994	Final NUREG issued

1992 NPRDS DATA REVIEW

May 1994	1992 failure data down loaded; begin initial screening
July 1994	Questionnaires distributed
May 1995	Data compiled; draft report available
June 1995	Industry review of draft report at Summer NIC meeting
December 1995	Final NUREG issued

1993 NPRDS DATA REVIEW

May 1995	1993 failure data down loaded; begin initial screening
July 1995	Questionnaires distributed
May 1996	Data compiled; draft report available
June 1996	Industry review of draft report at Summer NIC meeting
December 1996	Final report issued.

NPRDS Enhancements. Based on lessons learned from NPRDS failure data reviews, a list of desired information to be made available in either the NPRDS engineering record or failure record for each valve has been formulated. NIC has initiated discussions with INPO to upgrade the NPRDS database itself. NIC also plans to contact cognizant check valve engineers at each

utility to encourage them to work with their NPRDS reporter in order to improve the information in each NPRDS report. Table 1 is a list of NPRDS enhancements proposed by NIC at their Winter 1993 meeting (the last four items are already in use; however, utilities need to ensure that they are used properly). The revisions currently in process to NPRDS are planned to accomplish these enhancements.

Strategic Plan. In order to establish the proposed centralized failure/reliability database, a strategic plan must be developed. This plan must address the issues of

- Procedures for data control and update
- Responsibility for operation and maintenance of the database
- Ability to add new data fields and support future efforts
- Database access
- Review and coding of new data.

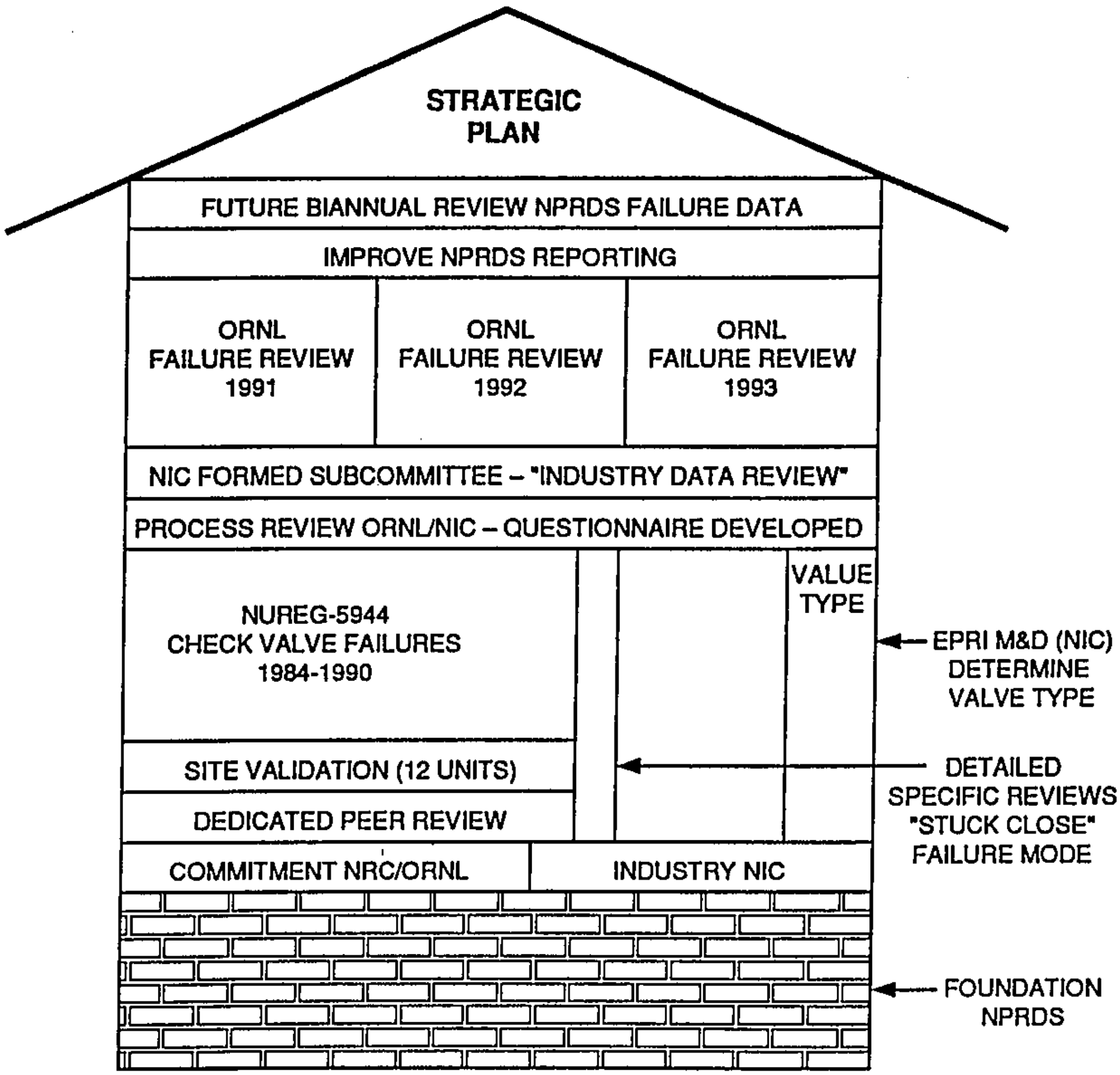
NPRDS reporting practices must also be enhanced to incorporate the needs of this and similar databases and to improve the efficiency and cost for future updates. Figure 3 illustrates the "building blocks" necessary to develop such a database.

CONCLUSION

Although the check valve failure database developed from the ORNL review of NPRDS failure records has some limitations, it has been used successfully to produce cross-correlations and analysis data unavailable from past analysis efforts. The database has also been used successfully as a basis to initiate specific case studies, as exemplified by the "stuck closed" valve study. Ideally, however, in order to exploit its full usefulness, such a database should be upgraded and supplemented to provide both specific valve failure information and overall reliability information for any valve type, manufacturer, operating environment, configuration, and other parameters. This database would be maintained in a centralized location and updated at least biannually. The database would be accessible to any check valve engineer at any site, the USNRC, valve manufacturers, and other related vendors (with some limitations), and would provide a mechanism to allow the implementation of tools and methodologies using component failure data as their basis.

Table 1. NIC-proposed NPRDS enhancements.

Data field	Importance	Engineering record	Failure record
Valve type	Needed	X	—
Valve type details	Desired	X	—
Design features	Desired	X	—
Failure area	Found in description	—	X
Installation configuration	Low	X	—
Application	Low (some already coded)	X	—
Program	Desired	X	—
Root cause	Already coded	—	X
Repetitive failure	Already coded	—	X
Modification involved	Already coded	—	X
Design problem	Already coded	—	X



ORNL-DWG 94M-2380 ETD

Figure 3. Building blocks for a check valve database.

Because the current population of check valves used in nuclear power plants is relatively small, the proposed check valve database is believed to be a manageable effort. If efforts to establish such a database are successful, extension to other types of valves and components is logical. Perhaps the next logical step would be to establish a failure database for motor-operated valves or air operated valves, with progressions to pumps and motors.

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Appendix A

Stuck Closed Check Valve Study

Appendix A

Stuck Closed Check Valve Study

INTRODUCTION

In December 1992, the Nuclear Industry Check Valve Group (NIC) subcommittee on Industry Data Review initiated a task to analyze in detail all failures identified in the 1984–1990 analysis[a] having a failure mode of "stuck closed." This group of failures was selected for further analysis for several reasons:

- All events characterized as having a stuck closed failure mode were classified as severe.
- A manageable number of failures was reported (83 out of 1,227 events analyzed in NUREG/CR-5944 were characterized as stuck closed).
- This failure mode represents one of the most detrimental conditions (e.g., failure of a check valve to open could defeat a train or system function).

PURPOSE OF REVIEW

The purpose of the review was multifold:

- Understand in detail the failure modes, failure population, and root causes for this important block of failures
- Determine the feasibility and functionality of data review and analysis at a detailed level
- Identify methodology or data problems that would hinder an analysis at a detailed level
- Produce concrete, supportable conclusions and recommendations to demonstrate the significance of a detailed review and analysis
- Provide conclusions that would support improved check valve program development
  - Identify factors that may result in increased failures
  - Identify "good actors"
  - Identify specific factors/situations that demonstrate increased failures
- Provide the foundation for establishing rules and guidelines for future reviews to ensure required uniformity and control (to allow for data combination/cross reference).

METHODOLOGY

The basis for the review of the stuck closed events was NUREG/CR-5944. This study classified all significant failures (i.e., those involving internals degradation) reported in the Institute of Nuclear Power Operation (INPO) Nuclear Plant Reliability Data System (NPRDS) during the analysis period of 1984–1990 according to failure mode (among other parameters). The "stuck closed" failure mode was described in the NUREG as "Valve will not open when forward pressure is applied."

At the 1992 winter NIC meeting, the Industry Data Review subcommittee reviewed the preliminary NUREG data in order to determine the additional information that would be required for check valve experts to perform a detailed review of the stuck closed failures. A "detailed review"

a. Oak Ridge National Laboratory, *A Characterization of Check Valve Degradation and Failure Experience in the Nuclear Power Industry*, NUREG/CR-5944, September 1993.

is defined as a review of each individual failure to obtain as much information as possible about that failure and its relationship to similar failures. Based on their review, questionnaires were sent to the 37 utilities that reported the stuck closed failures. The following specific additional information was requested:

- Confirmation of failure
- Specific valve type (e.g., swing, lift, tilting disc)
- Stem/hinge penetration
- Valve application
- Site program(s) that valve was included in [e.g., inservice testing (IST) program, 86-03 program, preventive maintenance (PM) program]
- Details of failure discovery.

Approximately one-third of the utilities initially responded to the survey. A preliminary summary of the data was provided at the summer NIC meeting in June 1993. Individual NIC members contributed additional data, and NIC solicited all remaining utilities to provide their input. The remaining information was gathered prior to the winter NIC meeting in December 1993.

Supplemental data gathered from the utilities was linked to the original NUREG data using a relational database. Evaluations were based on the combined data of the two efforts.

RESULTS

Fifteen of the 83 reported failures (18%) initially characterized as "stuck closed" were not legitimate stuck closed check valve failures (i.e., the valve was not a check valve or the valve did not actually stick closed). Therefore, the actual analysis involved the 68 remaining failures.

Site Valve Programs

As the scope of NPRDS varies from site to site, so do PM programs and the response to INPO Significant Operating Experience Report (SOER) 86-03. Some check valves reported as having failed were not included in any site valve program at the time of failure, while others were included in one or more site programs. Twenty-one percent of the 83 valves were either in no program or had an unknown program status. Eighteen percent of the original failures were determined to be invalid for the purposes of this study, while 12% were included in the site 86-03 program, and 42% were included in the IST program. Seven percent of the valves were included in both 86-03 and IST programs

To measure the effectiveness of the various valve programs, some factors must be considered in greater detail. The analyst must ideally know

- What program(s) the check valve was included in
- Whether the failure was identified as a result of the program(s).

This study could not determine the effectiveness of the site valve programs. To make this determination, an additional valve population study would be required. Using a population study and assuming a relationship between plant system and valve program(s), some conclusions might be attempted.

Valve Age

Because Since the number of valves included in this study was small and the other factors affecting the failure mode were thought to be more significant (e.g., specific valve type, application), a review of age effects was not considered for the total population, but rather individually by specific valve type.

Specific Check Valve Type

Initial discussions by the NIC subcommittee on data review identified the importance of basing a detailed review on specific check valve

type. This information was determined to be essential to a detailed analysis because it was believed that failure mechanisms should vary with valve type. For example, while sticking closed was thought to be a valid failure mode for lift check valves, it was difficult for the subcommittee to imagine the mechanism required to stick a simple swing check valve shut.

Two factors were apparent from the results of the review of the 68 valid stuck closed failures:

- Lift/piston type check valves are much more prone to failing by sticking closed than were either tilting disc or swing check valves
- Twenty-three failures were vacuum breaker valves that failed to open at a precise set pressure.

Lift/Piston Check Valves

Sixty percent (41) of the 68 valid stuck closed failures involved lift/piston type check valves. This is thought to be largely a result of the tight clearances inherent between the disc and the body or body guides of these types of valves. The material composition of the valve can increase such an effect. Carbon steel can rust and pit and is susceptible to bacterial growth and biological fouling that can lead to binding of internal components. Table A-1 shows that the carbon steel valves had more failures and a shorter life than did the stainless steel valves (although it must be recognized that this data is not normalized; i.e., population effects were not considered for this analysis, and may have a significant effect, once determined).

Table A-1. Lift/piston check valves—material comparison.

Material	No. of valves[a]	Age to failure (yr)
Carbon steel	35	1–19
Stainless steel	5	>16
Other	1	21

a. Including vacuum breakers.

General causes of failure were attributed to dirt, rust, and crud buildup. It appears that the use of lift/piston check valves in raw water systems increases the probability that binding will occur because even small particles can jam or stick in the area between the disc and body and prevent movement. A review of some vendor manuals pointed out that this potential does indeed exist. (It should be noted that stainless steel valves are not typically used for these systems because of cost considerations.)

Utilities were able to mitigate problems with these types of valves by increasing inspection intervals and by either eliminating the valve, upgrading the material (to stainless steel), or changing the valve type. Few repeat failures were noted over the study's time period (1984–1990).

Swing Check Valves

Only six failures of swing check valves were reported during the NUREG analysis period (excluding 13 vacuum breaker failures). Table A-2 provides the analysis of each failure in detail.

The decreased susceptibility of the swing check valves (compared with other types of check valves) to stuck closed failure is demonstrated by their age to failure, which occurred between 9 and 17 years. The mean age to failure was 14 years. No failure was reported prior to 9 years of service. Five out of the six failures of swing check valves were on carbon steel valves.

Table A-2. Swing check valve failures.

Number of valves	Size (in.)	Cause of failure	Corrective action
1	3/4	Poor design	Replace valve
2	2	Welded bonnet design prevented normal maintenance	Remove internals
1	10	No failure cause reported; failure detected by IST program	Not given
1	20	Insulation interfered with external arm	Modify valve to ensure proper clearance
1	24	Mission type valve out of service for extended period (>6 months) in raw water system. Valve found packed with mud and unable to open	Program changes instituted to ensure that valve is flushed every 90 days if not in service

Tilting Disc Check Valves

The tilting disc design is in some ways similar to the swing check design. Its failure performance also appears to be similar. Seven of eight failures involving tilting disc valves were on carbon steel valves. The mean age to failure was 13 years, with a range from 9 to 17 years.

Five tilting disc valve failures involved valves that were considered of low safety importance and were not included in any site valve program. The utility considered it acceptable practice to operate these valves until failure.

Another five tilting disc valve failures involved valves built by the same manufacturer whose design incorporates two features possibly contributing to the failures:

- A split body design on a 45-degree angle that could cause a pinching effect
- Angled seats, which if closed under high pressures could jam shut.

A unique hinge pin lubrication system and a potential for extremely tight clearances combined with unusually hard bushing/pin material may have contributed to the stuck closed failures of these tilting disc valves. It appeared that further discussions with the valve manufacturer were warranted.

Vacuum Breaker Valves

Of the 41 reported stuck closed failures involving lift/piston check valves, 10 were vacuum breaker valves. These valves had a mean life of 9 years and a range to failure from 6 to 14 years. Of the 10 failed valves, nine were subsequently modified to improve performance. The most common modification was the removal of the spring to allow for easier opening.

Of the 19 failures involving swing check valves, 13 were vacuum breaker valves. These valves had a mean life of 4 years and a range to failure of 1 to 7 years. Of the 13 valves, 12 were at the same plant and are scheduled for modifications to allow for easier opening. Stroking frequency was increased to once every 6 months for the other valve in order to eliminate binding.

Typically, vacuum breaker failures were failures of the valve to open at a prescribed set point. In some cases, the valve was required to open at as little as 25 in.-lb of torque. In a sense, this type of failure is more of a set point problem typical of safety relief valves (SRVs) than of other check

valves. The "Extent of Degradation" classification (NUREG/CR-5944) of "severe" may also not be warranted in the cases reported because the valve would have been able to open and allow flow, but at a reduced level or slightly higher pressure. Because this failure mode is not representative of check valves as a group, consideration should be given to grouping vacuum breaker failures separately.

CONCLUSIONS AND RECOMMENDATIONS

An analysis of check valve failures with a failure mode of "stuck closed" revealed the following:

- Detailed reviews are feasible and can be performed with a minimum of effort (assuming utility cooperation).
- Information can be assembled and conclusions reached that can be used to support improved utility check valve programs (i.e., identification of factors that may contribute to increased failure rates, assist in valve application, and testing frequencies).
- Problems can be identified that may impede future detailed reviews and analyses.
- Population effects (i.e., data normalization) must be considered when analyzing data for specific conclusions.
- Such activities may be used to develop a standard methodology.

Specific conclusions from the study include the following:

- Check valves are not particularly susceptible to "stuck closed" failures [only 83 out of 1,227 (7%) of the failures analyzed from 1984–1990 involved this failure mode].
- Of the 83 failures analyzed in detail, only 68 were determined to be valid stuck closed failures. Of these, lift/piston type check valves were the most susceptible to failure due to sticking or binding caused by rust, dirt, and crud accumulation. Twenty-three of the 83 failures (28%) involved vacuum breaker valves failing to open at a precise set pressure.
- Sticking closed is a very low probability failure mode for simple swing type check valves.

  Age to failure is significant for swing or tilting-disc type check valves (>9 years).

  Utilities have made a concerted effort to improve reliability of valves that have failed stuck closed.

  During the data review, the utilities were slow to respond to requests for information and insufficient information (which valves were included in site valve programs, whether failures were discovered as a result of the programs, etc.).

Specific recommendations resulting from this review are discussed below:

- Because of their design differences from typical check valves, vacuum breaker valves should be considered as a separate classification. These valves were involved in over one-third of the valid stuck closed cases. Typically, they were not "stuck closed" in the sense that the valve would not open under normal operating conditions, but rather that they failed to open at a prescribed set point under test conditions. The failure mode of vacuum breaker valves appears to be similar to that of SRVs.
- Lift/piston check valve applications in dirty or stagnate systems should be reviewed by individual utilities in order to assess their susceptibility to sticking closed. Measures to mitigate the potential for failure may include:

  Flushing

- Valve replacement
- Increased review/analysis
- Increased testing
- Vendor-specific review
- Cleanup of dirty systems.

- Additional review of tilting-disc type valves with a split body design may be warranted. Evidence suggests that this design may be particularly susceptible to sticking closed because of its 45-degree angle, which could cause a pinching effect, and angled seats, which if closed under high pressures could jam shut. A unique hinge pin lubrication system and a potential for extremely tight clearances combined with unusually hard bushing/pin material may have contributed to the stuck closed failures of these tilting disc valves.

- A methodology should be developed for detailed failure review, the approach to and presentation of failure data should be standardized, and the analysis of stuck closed failures should be continued based on data available from annual NUREG updates.

Appendix B

Analysis of 1991 NPRDS Failure Data

Appendix B

Analysis of 1991 NPRDS Failure Data

INTRODUCTION

In order to provide a thorough assessment of historical check valve failure experience, the USNRC committed to support ORNL in conducting updates on failure data for 1991 and 1992. Accordingly, ORNL initiated a review of the NPRDS failure data for 1991 in May of 1993. The process followed was consistent with that used for the 1984–1990 analysis,[a] but was supplemented with information obtained directly from utilities. This additional information included specific valve type, detailed failure narratives, valve orientation, proximity to upstream disturbances, whether the failure was due in part to design, and an assessment of ORNL-characterized parameters, such as failure area, failure mode, and severity of failure. This utility input provided not only supplemental information not available from NPRDS, but also an increased level of confidence in the quality of data used in the failure analysis. Information was entered into a failure database, combined with the NPRDS check valve population database, and used to conduct an analysis of check valve failures for 1991.

a. Oak Ridge National Laboratory, *A Characterization of Check Valve Degradation and Failure Experience in the Nuclear Power Industry*, NUREG/CR-5944, September 1993.

RESULTS

Because the USNRC is primarily interested in trending industry performance, the effort focused on comparison of results of the 1991 analysis with those of the 1984–1990 study. This appendix discusses significant trends identified from the analysis. It also presents a look at additional findings related to specific valve type (data that were not available in the previous analysis), information that is especially important to performance of detailed check valve failure analyses. (It should be noted that since the results of the 1991 analysis have not yet been published, data presented herein should be considered preliminary.)

Figure B-1 shows that of the 401 failures included in the 1991 study, 76% were discovered programmatically. A "programmatic" discovery process refers to failure discovery during the conduct of a surveillance test, inservice inspection or test, leak rate test, or during another type of test or periodic preventive maintenance. Nonprogrammatic discovery methods include routine or incidental observation, abnormal equipment

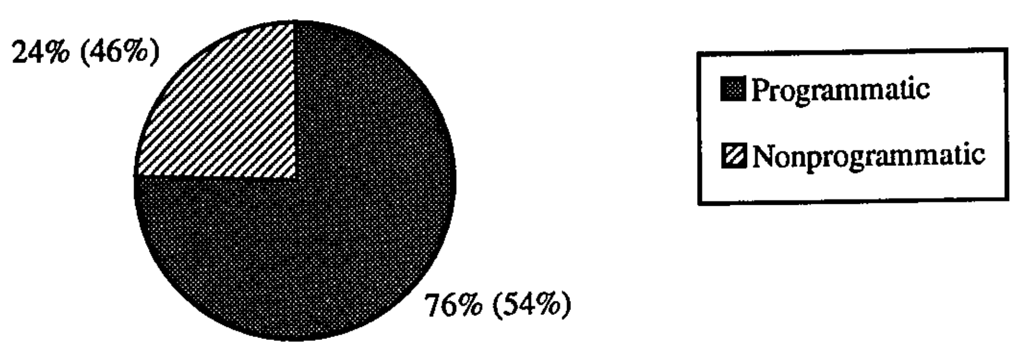

Figure B-1. Distribution of failures by general discovery process (values in parentheses are results of the 1984–1990 study).

operation, special inspection, or an unclear discovery method. Compared with only 54% of the 1984–1990 failures discovered by programmatic means, this represents a significant positive trend toward controlled check valve performance evaluation and failure detection.

Figure B-2 illustrates the failure distribution by extent of degradation, defined for purposes of this analysis as either moderate or significant. "Moderate" failures include failure of the valve to seat properly, moderate internal leakage, loose internal assembly (without attendant problems, such as stuck open), or a miscellaneous failure in which the level of degradation was not evident from the failure narrative. "Significant" failures include those with broken or detached internals, restricted motion, stuck open and stuck closed cases, cases where valves failed to open at set pressure, and excessive internal leakage. It should be noted that only 36% of the 1991 failures were classified as significant, compared with 53% in 1984–1990.

Failure distribution by failure mode is shown in Figure B-3. Another positive trend is evident here, and is related to the number of significant versus moderate failures. Failures resulting from improper seating increased from 45% in 1984–1990 to 63% in 1991 (moderate failures), while those attributed to significant failures declined. For example, stuck open failures dropped from 28 to 11% of the total number of failures, disc/other part off or broken fell from 10 to 4% of the total, and stuck closed decreased from 7 to 4% of the total number of

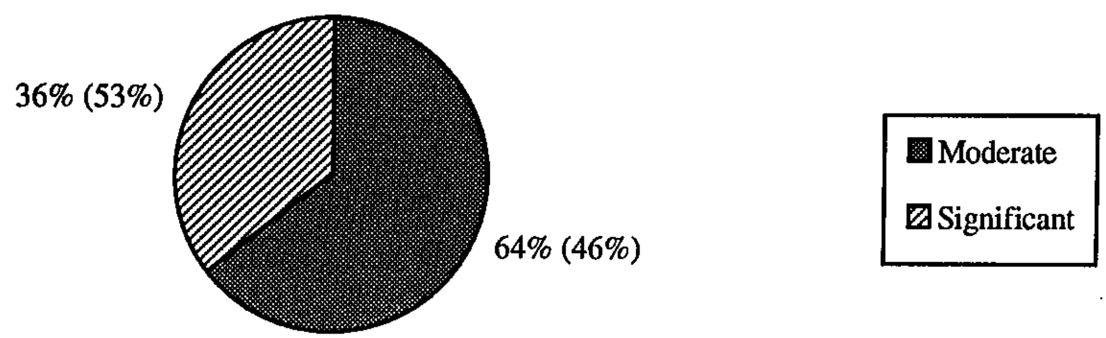

Figure B-2. Distribution of failures by extent of degradation (values in parentheses are results of the 1984–1990 study).

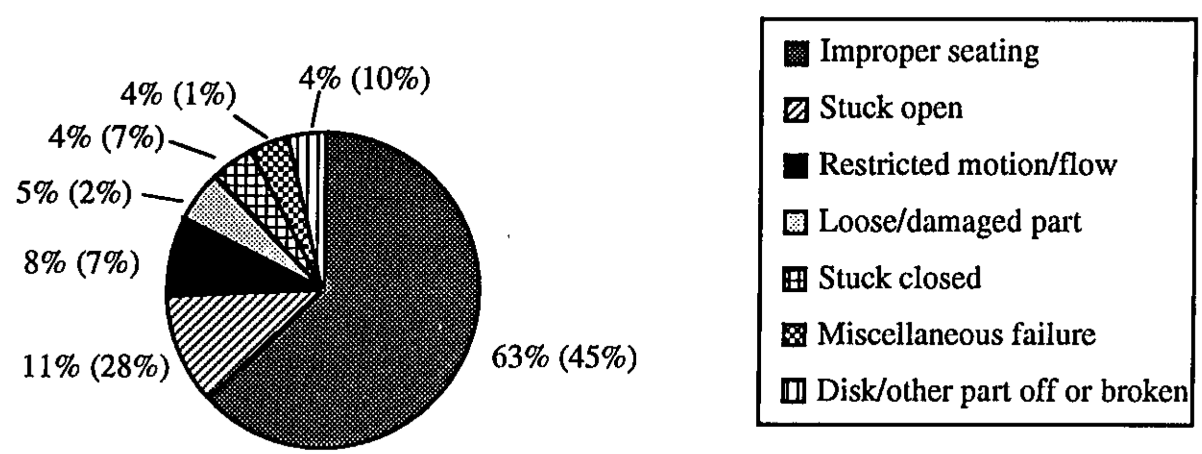

Figure B-3. Distribution of failures by failure mode (values in parentheses are results of the 1984–1990 study).

failures. Only slight increases were noted in the percentages of failures attributed to loose/damaged part (from 2 to 5%).

Figure B-4 shows the relative failure rate by system for systems with the highest failure rates. Containment isolation, diesel starting air, and suppression pool support had the highest relative failure rates for 1991. Emergency service water (ESW), feedwater, and diesel starting air had the highest relative failure rates for 1984–1990. Note that ESW dropped to twelfth place, while feedwater fell to fourth place in the 1991 analysis. Only systems with 100 or more valves were considered for the 1991 analysis, and data presented are normalized using the procedure developed for the 1984–1990 analysis. This procedure involves determination of an overall failure rate for all check valves (for 1991), and application of this value to the individual category failure rates to determine the "Relative Failure Rate" (NUREG/CR–5944).

Failure distribution according to specific valve type is presented in Figure B-5. Information for this chart was obtained primarily from utilities who responded to a questionnaire developed and distributed by NIC for the 1991 analysis. Additional information was obtained from manufacturer catalogs and the EPRI check valve database. Failures are nearly evenly divided between lift checks and swing checks (34% and 33% of the total failures, respectively), while 10% were tilting-disc valves, 5% were duo/double disc, and 2% or less of stop checks, in-line checks, and other types of check valves. Only 12% of the valves represented in the 1991 failure analysis could not be identified according to their specific type. This information cannot be compared with the check valve population for normalization because specific valve type information is not yet available for the population database. This study will become the groundwork for future efforts, including establishment of the proposed centralized failure/reliability database.

Figure B-6 is an example of data unavailable before the 1991 analysis. Figure A-6 depicts failure distribution by specific valve type and failure mode. The figure shows, without further detailed analysis, that no failures of swing check valves were reported in 1991 with a failure mode of stuck closed, while approximately one-tenth of the lift check valve failures were attributed to this mode. It is also obvious that regardless of valve type, the greatest fraction of failures was attributable to improper seating.

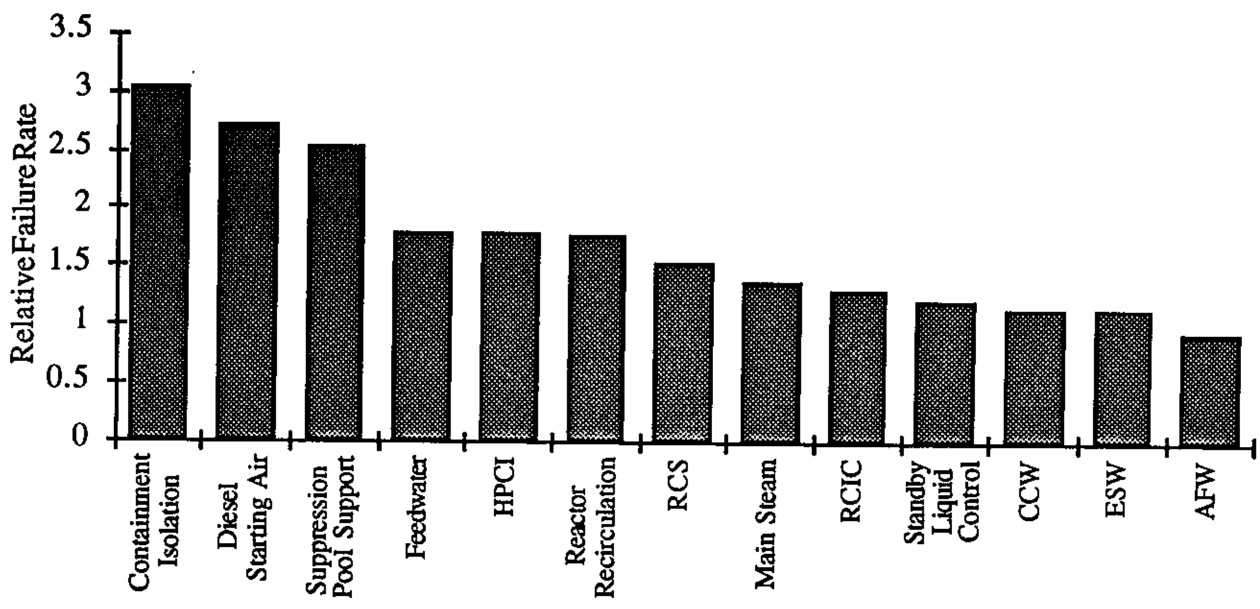

Figure B-4. Relative failure rate by system for systems with the highest failure rates.

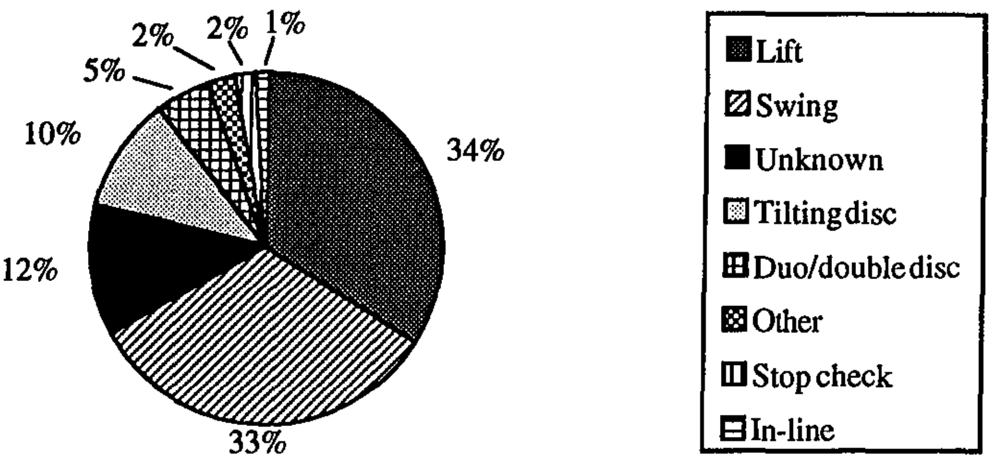

Figure B-5. Distribution of failures by specific valve type.

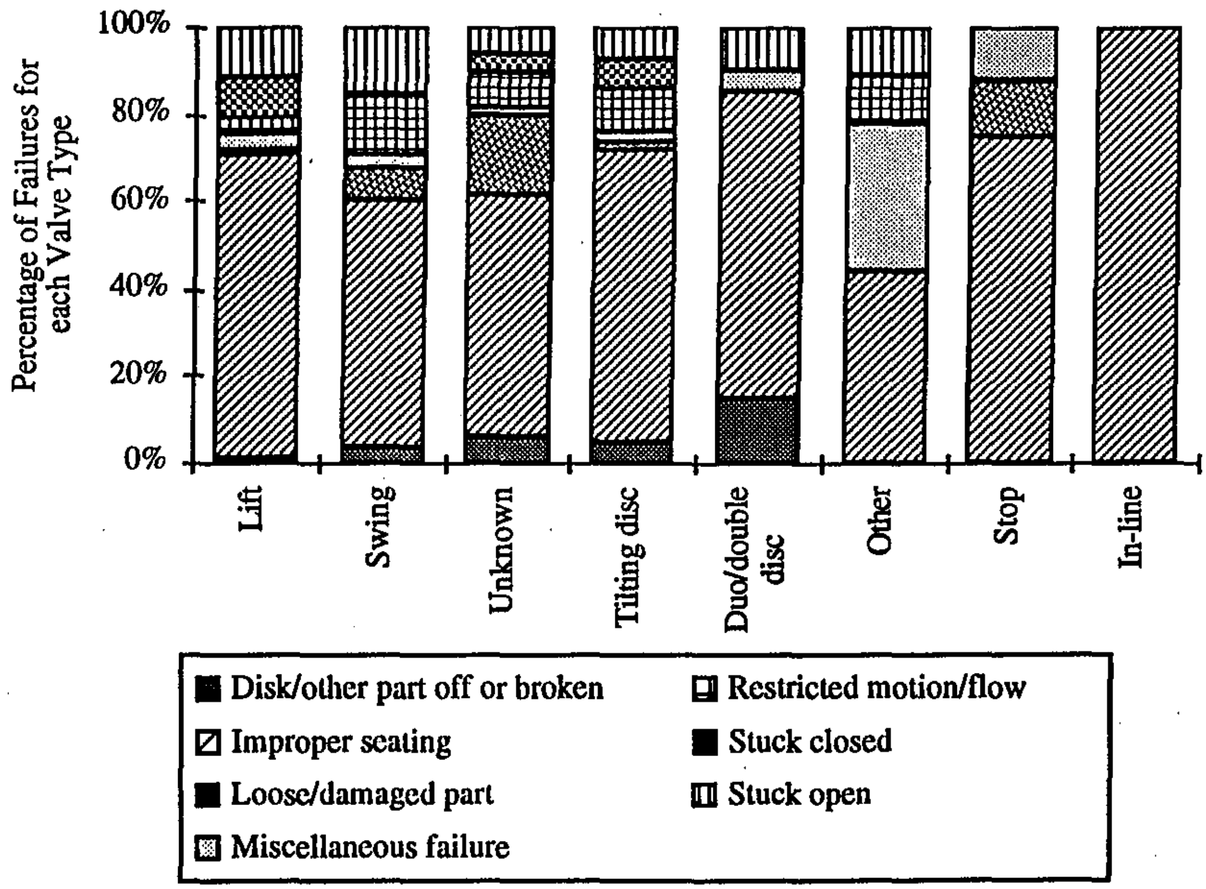

Figure B-6. Distribution of failures by specific valve type and failure mode.

CONCLUSIONS

From the summary of preliminary results of 1991 NPRDS check valve failures analyzed by ORNL, it is apparent that a positive trend exists regarding general discovery process (i.e., programmatic versus nonprogrammatic), extent of degradation, and failure mode. A more detailed analysis is underway, and will be presented in the NUREG that updates NUREG/CR-5944 for the 1984–1990 analysis. Approximately 88% of the valves included in the 1991 analysis were classified according to their specific valve type, and using this information, more detailed analyses can be performed than from prior data. It is anticipated that this type of data will again be requested from the utilities for the 1992 update and will be used to form the basis for the proposed failure/reliability database.

Validation of TVA's Generic Letter 89-10 MOV Design Methodology

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ABSTRACT

The Tennessee Valley Authority's (TVA) plan for addressing the issues in the U.S. Nuclear Regulatory Commission's Generic Letter 89-10 includes a calculation methodology to determine the thrust/torque required for gate and globe valves to overcome pressure during opening and closing. The calculation methodology was developed to contain enough conservatism to ensure that the calculated thrust would envelope the actual required thrust.

TVA committed to review differential pressure test results against calculated values to verify the equations and factors and to revise the calculation methodology where necessary. This paper will discuss the calculation methodology that TVA uses and present the process that is used to reconcile test results with calculated values.

BACKGROUND

The Tennessee Valley Authority (TVA) has developed a calculation methodology to estimate the thrust required for gate and globe valves to open or close against design-basis differential pressure and perform their safety related function. This methodology was developed in order to implement the recommendations contained in U.S. Nuclear Regulatory Commission's Generic Letter 89-10 (GL 89-10) "Safety-Related Motor-Operated Valve Testing and Surveillance."

PURPOSE

The purpose of this paper is to present the calculation methodology used by TVA in it's GL 89-10 program and the methodology used to reconcile results obtained during valve static and dynamic testing with the calculated values.

CALCULATION METHODOLOGY

This paper will describe the equations TVA uses for determining thrusts for gate and globe valves. TVA has opted to perform a design basis review on butterfly valves and contract with the valve manufacturer to perform the torque calculations. TVA will perform an acceptance review of the calculations prepared by the butterfly valve manufacturer.

The equations and factors TVA uses for determining thrusts for gate and globe valves were developed in conjunction with Siemens Power Corporation, TVA's technical consultant for GL 89-10 issues. The calculation methodology also uses information from the *Application Guide for Motor-Operated Valves in Nuclear Power Plants*, published by the Electric Power Research Institute (EPRI) Nuclear Maintenance Application Center (NMAC).[a] Feedback from the EPRI Motor Operated Valve Performance Prediction Program (PPP) was also factored into the TVA methodology. Nomenclature for the equations is listed in Table 1.

a. Available from EPRI/NUMARC, NP-6660-D.

Table 1. Nomenclature.

μ	=	friction factor seat/wedge (0.4)
θ	=	wedge angle (degrees from stem axis); seat angle for globe valves
A	=	stem area
A_o	=	orifice area of the valve $\pi D2/4$ (gate) $\pi(D2-d2)/4$ (globe)
A_s	=	area of the seat (i.e., circumference × seat width)
$CM_{\%}$	=	capability margin (percent)
CM_{Th}	=	capability margin (thrust)
d	=	stem diameter
D	=	seat diameter at point of sealing (i.e., midpoint of seat ring)
dP	=	design differential pressure
dP_t	=	test differential pressure
F_{avg}	=	average running load (closing)
F_{dp}	=	differential pressure force acting on the disc
$F_{dp,t}$	=	differential pressure force determined from test data
F_k	=	thrust delivered to the seat
F_p	=	calculated piston effect load
$F_{p,open}$	=	fully opened piston effect load
F_{pack}	=	calculated packing friction load
$F_{pack,t}$	=	measured packing friction load, static test
F_r	=	total required thrust
$F_{r,max}$	=	max stem thrust (closing) (i.e., 1.15 Fr)
$F_{r,t}$	=	required thrust as determined from testing
F_s	=	seating force
F_t	=	measured thrust during test
$F_{t,maxdp}$	=	measured thrust at maximum dP during test
$F_{tst/dp}$	=	thrust measured at torque switch trip during dP test
$F_{tst/st}$	=	thrust measured at torque switch trip during static test
F_u	=	additional thrust, beyond that required to overcome dP, required to open valve
$F_{u,t}$	=	measured unseating thrust during test
F_v	=	safety factor
F_w	=	unwedging load
$F_{w,t}$	=	measured thrust at unseating during test
f_w	=	wedge factor
LC	=	thrust capability of limiting component
LSB	=	load sensitive behavior (rate of loading)
P	=	line pressure
P_t	=	line pressure measured during test with valve open
R_r	=	sealing force between seat and disc
S_s	=	4000 psi where dP = 0–500 psi
SF	=	stem factor
TQ	=	required torque
TQ_{pack}	=	stem torque required to overcome the tangential packing friction force, ft-lb
$TQ_{r,t}$	=	required torque determined from testing
TQ_t	=	measured torque during test
TSM_{Th}	=	torque switch margin, thrust
$TSM_{\%}$	=	torque switch margin, percent

Gate Valve Thrust Calculations

The TVA equation for gate valve thrust calculations takes into account the angle of the wedge and uses a valve safety factor of 1.2 and a friction factor of 0.4 for most gate valves. Based on the EPRI PPP, a friction factor of 0.6 is used for Borg Warner gate valves.[b] The methodology used for determining gate valve thrust requirements is in the following format:

$$F_r = F_{pack} + F_{dp} \pm F_p + F_w \quad (1)$$

The packing load is the force required to slide the stem through the packing, and is computed by multiplying the stem diameter by 1,000 lb.

The differential pressure force acting on the disc is calculated as

$$F_{dp} = dP * A_o * F_v \frac{\mu}{\cos\theta + \mu\sin\theta} \quad (2)$$

where plus (+) is used in the denominator of the equation for opening stroke calculations, and minus (−) is used for closing stroke calculations.

The safety factor, F_V, used in this equation adds conservatism to account for effects such as varying amounts of friction between the seat and disc, degraded valve seat condition, and differences between thrusts measured during static and dynamic tests (referred to as load sensitive behavior[c] or rate of loading).

b. The friction factor is an invalidated factor that is based on the best available information. This term will be addressed by the reconciliation process described later in this paper.

c. Not enough industry data are available to quantify load sensitive behavior at this time. The reconciliation process discussed later in this paper will evaluate the load sensitive behavior observed during testing to ensure that the overall calculation methodology contains enough conservatism to envelope this factor.

The piston effect load accounts for the force from the internal line pressure acting on the stem. It assists the actuator in the opening direction and resists the actuator in the closing direction. The piston effect is computed as

$$F_p = P * A \quad . \quad (3)$$

The force required to pull the wedge out of the seat is applied for solid and flex wedge gate valves during the open stroke and is calculated as

$$F_w = F_k * f_w * F_v \frac{1 - \mu\tan\theta}{\sin\theta + \mu\cos\theta} * \frac{\mu}{\cos\theta + \mu\sin\theta} \quad (4)$$

$$F_k = F_{r,max} - F_{pack} - F_p - F_{dp} \quad \text{(closing values)} \quad (5)$$

In this equation the maximum stem thrust, $F_{r,max}$, accounts for inertia effects during closing and control switch contactor drop time. The wedge factor, f_w, is dependent on the flexibility of the wedge (i.e., 0.6 for flex wedge and 1.0 for solid wedge valves).

Globe Valve Calculations

The globe valve methodology uses the following equations:

$$F_r = F_{pack} + F_{dp} + F_p + F_s \text{ (closing)} \quad (6)$$

$$F_r = F_{pack} + F_{dp} \text{ (opening)} \quad (7)$$

where

$$F_{dp} = dP * A_o * F_v \quad (8)$$

$$F_p = P * A \quad (9)$$

$$F_s = R_r \sin\theta + \mu R_r \cos\theta \quad (10)$$

$$R_r = S_s * A_s \; . \quad (11)$$

In Equation (8), TVA uses a safety factor, F_V, of 1.2 in the opening direction and 1.0 in the closing

direction. The 1.2 factor accounts for considerations such as relief of the sealing load, hydraulic effects of flow over the seat, and degraded packing.

Also in Equation (8), determination must be made as to whether the valve seat area or disk guide area should be used to determine A_O. This determination is based on the following criteria:

1. **Seat-Based Valves**—valves where differential pressure acts across the disc seating area for all stroke positions. The most restrictive flow area in a seat-based valve occurs at the valve seat orifice. Flow is not impeded by the low disc guide at the exit port of the valve.

2. **Guide-Based Valves**—valves where the differential pressure acts across the disc-guide area for some portion of the full range of stroke positions. The full differential pressure acts across the disc-guide area when flow is restricted by the lower disc guide at the outlet port of the valve.

In Equation (11), the area of the seat is calculated assuming line contact and using a seating width of 0.0625 in. Line contact generally occurs when the disc angle and seat angle varies by more than 0.5 degrees.[d]

Actuator Torque

Using the total required thrust (F_r), the required actuator torque (TQ) for rising stem valves is determined by

$$TQ = F_r * SF \quad . \tag{12}$$

The stem factor, SF, which is used to convert thrust to torque, can be calculated or obtained from the Limitorque selection index based on coefficients of friction (COFs) of 0.20 and 0.15. TVA uses a stem factor based on COF of 0.15, which is consistent with current lubrication practices.[e] This is based on the use of a bronze stem nut and could be changed if brass were used for the stem nut material. The COF could be 0.1 or less for roller stem screw assemblies if vendor test data is available.

When determining the torque requirements for rising **and** rotating stem globe valves, an additional torque component is considered. This torque component, the stem torque that must be developed to overcome the tangential packing friction force resisting the stem rotation is computed as

$$TQ_{pack} = \frac{d * F_{pack}}{24} \quad . \tag{13}$$

Therefore, for rising **and** rotating stem globe valves, the required actuator torque (TQ) is determined by

$$TQ = (F_r * SF) + TQ_{pack} \quad . \tag{14}$$

RECONCILIATION PROCESS

Figures 1 and 2 show typical reconciliation data sheets. Page 1 of each figure records information from the MOV design calculations and the differential pressure tests, which is necessary to perform the reconciliation. Page 2 of the figures compares the information predicted by the design calculation with the actual test results (extrapolated to design basis conditions). The shaded cells of the figures indicate values that TVA has set up for automated calculation, which is accomplished by entering formulas into the table cells. TVA uses a common personal computer word processor to perform this automation. Automated reconciliation can also be set up using common spreadsheet software.

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d. Crane Aloyco Bulletin EB009.

e. Use of a COF of 0.15 assumes reasonable lubrication practices. This factor is evaluated during the reconciliation process discussed later in this paper.

Plant: Unit: Valve UNID:

VALVE INFORMATION			
Manufacturer:		Stem Diameter:	
Size:		Mean Seat Diameter:	
Pressure Class:		Seat Angle (ϴ):	
Disc Style:		cos ϴ:	
Stem Orientation:		sin ϴ:	

ACTUATOR INFORMATION					
Manufacturer:	Limitorque	Type:	SMB	Size:	

MOV DESIGN BASIS INFORMATION			
Calculation Number:			
DP, Closing:		DP, Opening:	
Seat Friction Factor:		Stem Factor:	
Limiting Thrust (Close):		Limiting Thrust (Open):	

MOV TEST INFORMATION			
Reference WRs:			
Max. Test DP:			
Packing Load, Closing: (Static)		Packing Load, Opening: (Static)	
Req'd Closing Thrust:		Req'd Opening Thrust:	
Req'd Closing Torque:		Req'd Opening Torque:	
Thrust @ TST - Static:		Torque @ TST - Static:	
Thrust @ TST - DP:		Torque @ TST - DP:	
Measured Unseating Thrust:		Measured DP Thrust - Opening:	
Thrust Sensor:			

Figure 1. Data sheet—gate valves.

GLOBE VALVE CLOSING STROKE RECONCILIATION					
PARAMETER		CALCULATION		TEST	
Required Thrust/Torque (lbs/ft-lbs)		Thrust:		Thrust:	
		Torque:		Torque:	
Packing Load:					
Load Sensitive Behavior (Rate of Loading) (%)		N/A			
Stem Factor:	@ Static TST				
	@ DP TST				
	@ Required Closing Thrust				
Capability Margin (lbs thrust/percent)		N/A			
TS Margin (lbs thrust/percent)		N/A		Thrust:	
				Percent:	

GLOBE VALVE OPENING STROKE RECONCILIATION				
PARAMETER	CALCULATION		TEST	
Required Thrust/Torque (lbs/ft-lbs)	Thrust:		Thrust:	
	Torque:		Torque:	
Packing Load (lbs):				
Stem Factor @ Max. Required Opening Thrust:				
Capability Margin (lbs thrust/percent)	N/A		Thrust:	
			Percent:	

Figure 1. (continued).

Plant: Unit: Valve UNID:

VALVE INFORMATION					
Manufacturer:		Stem Diameter:			
Size:		Stem Orientation:			
Pressure Class:					
ACTUATOR INFORMATION					
Manufacturer:	Limitorque	Type:	SMB	Size:	
MOV DESIGN BASIS INFORMATION					
Calculation Number:					
DP, Closing:		DP, Opening:			
Limiting Component (Closing):		Limiting Thrust (Closing):			
Limiting Component (Opening):		Limiting Thrust (Opening):			
Stem Factor:					
MOV TEST INFORMATION					
Reference WRs:					
Max. Test DP:					
Packing Load, Closing: (Static)		Packing Load, Opening: (Static)			
Req'd Closing Thrust:		Req'd Opening Thrust:			
Req'd Closing Torque:		Req'd Opening Torque:			
Thrust @ TST - Static:		Torque @ TST - Static:			
Thrust @ TST - DP:		Torque @ TST - DP:			
Thrust Sensor:					

Figure 2. Data sheet—globe valves.

GATE VALVE CLOSING STROKE RECONCILIATION					
PARAMETER		CALCULATION		TEST	
Required Thrust/Torque (lbs/ft-lbs)		Thrust:		Thrust:	
		Torque:		Torque:	
Piston Effect:					
Packing Load:					
DP Load:					
Seat Friction Factor (Valve Factor):					
Load Sensitive Behavior (Rate of Loading) (%)		N/A			
Stem Factor:	@ Static TST				
	@ DP TST				
	@ Required Closing Thrust				
TS Margin (lbs thrust/percent):		N/A		Thrust	
				Percent	
Capability Margin:		N/A		Thrust:	
				Percent:	

GATE VALVE OPENING STROKE RECONCILIATION				
PARAMETER	CALCULATION		TEST	
Required Thrust/Torque (lbs/ft-lbs)	Thrust:		Thrust:	
	Torque:		Torque:	
Piston Effect Load:				
Packing Load (lbs):				
Unseating Load (lbs):				
DP Load (lbs):				
Seat Friction Factor (Valve Factor):				
Stem Factor @ Max. Required Opening Thrust:				
Capability Margin (lbs thrust/percent)	N/A		Thrust:	
			Percent:	

Figure 2. (continued).

Required Test Data

The following data from static and differential pressure testing are required to reconcile the test results with the design calculations. Figures 3 and 4 depict some of the common points on the diagnostic traces from the MOV test that are used for the reconciliation process.

Maximum test differential pressure (dP)—This is the maximum differential pressure measured during the dP test. Positioning of the pressure gauges in relation to the MOV under test is considered in the final evaluation of data. Because it is typically not possible to locate the pressure gauges immediately upstream and downstream of the MOV, the actual dP across the valve must be determined by calculating piping and head losses.

Packing load, closing and opening (static)—Because the opening and closing thrust (running load) during the dP test includes packing drag, piston effect, and dP force, it is difficult to accurately determine the portion of the total running load that represents packing load. Therefore, the running load from the static test is used as the packing load for the purposes of reconciliation.

Required closing thrust and torque—This is the thrust and corresponding torque required to close the orifice (i.e., when the disc wedges into the seat or at the point of greatest dP load), whichever is greater.

Required opening thrust and torque—This is the thrust and corresponding torque required by the actuator to fully open the valve. This will occur either at unseating or where dP load is highest.

Thrust and torque at torque switch trip, static—This is the torque and thrust from the static test that corresponds to the point on the appropriate diagnostic trace that indicates torque switch trip.

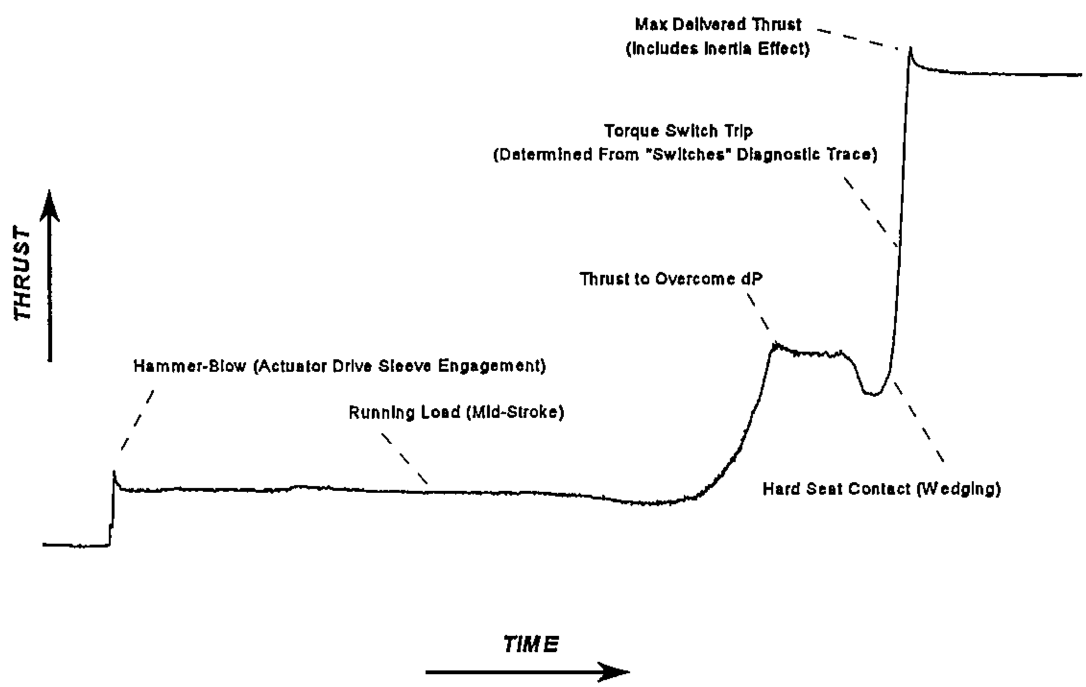

Figure 3. Typical gate valve diagnostic trace—closing direction.

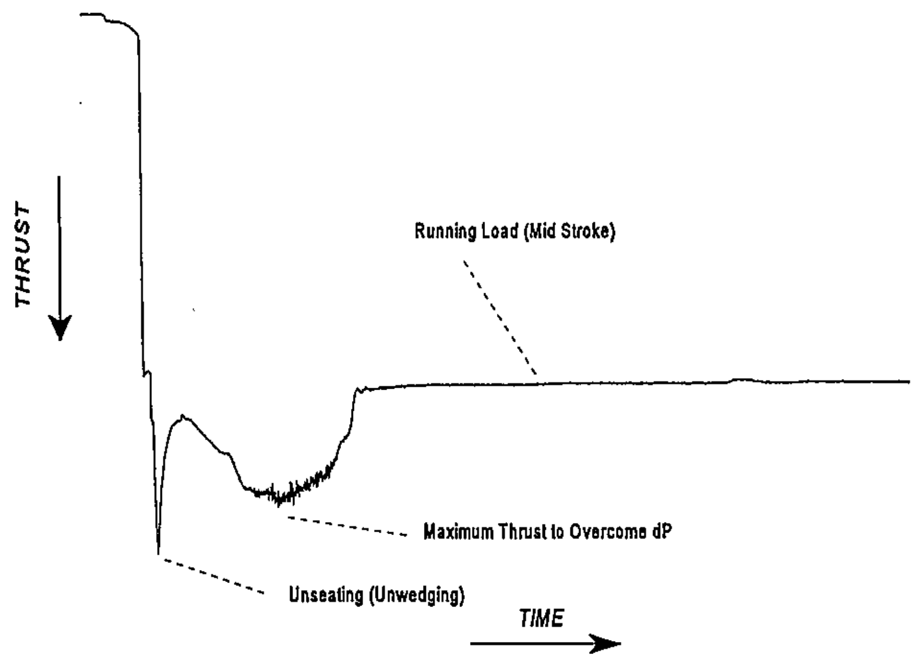

Figure 4. Typical gate valve diagnostic trace—opening direction.

Thrust and torque at torque switch trip, dP—This is the torque and thrust from the dP test that corresponds to the point on the appropriate diagnostic trace that indicates torque switch trip.

Measured unseating thrust (for gate valve reconciliation)—This is the thrust taken from the diagnostic trace where unseating (cracking) takes place.

Measured dP thrust, opening—This is the maximum thrust developed during the opening stroke from the dP effect.

Gate Valve Reconciliation

The following information describes the process for the closing stroke:

Required thrust and torque—For reconciling the test results with the thrust calculation, the test data must be extrapolated to the dP condition assumed by the calculation. Required thrust and torque (at the calculation design basis pressure) are determined as

$$F_{r,t} = [(F_t - F_{pack}) * (dP/dP_t)] + F_{pack} \quad (15)$$

$$TQ_{r,t} = F_{r,t} * (TQ_t/F_t) \quad (16)$$

Piston effect—This load is also commonly referred to as stem rejection load. Since the test results are reconciled to the design-basis pressure, the piston effect considered in the design calculation is used.

Packing load—Because the running load during the dP test includes packing drag, piston effect, and dP force, it is difficult to accurately determine the portion of the total running load that represents packing load. Therefore, the running load from the static test will be used as the packing load for the reconciliation.

Note: If line pressure is present during the static test, the running load will include a piston effect component. If this is the case, the packing load must be determined by subtracting the piston effect from the running load measured during the test.

dP load—This is the load that will be imposed on the valve by the differential pressure effect. The dP load is determined as

$$F_{dp,t} = F_{r,t} - F_{pack,t} - F_p \quad . \tag{17}$$

Seat friction factor (valve factor)—The seat friction factor is determined by substituting the appropriate terms back into the closing thrust equation defined in this paper. The equation used to solve for seat friction factor (μ) is as

$$\mu = \frac{F_{dp,t} \times \cos\theta}{(dP \times A_o) + (F_{dp,t} \times \sin\theta)} \quad . \tag{18}$$

Load sensitive behavior (also referred to as rate of loading)—Load sensitive behavior is the difference in thrust delivered at torque switch trip (TST) during the dP test as compared with the thrust delivered at TST during the static test. It is expressed as a percentage change and will be either positive or negative, depending upon the change from the static test, shown as

$$LSB = (F_{tst/dp} - F_{tst/st})/F_{tst/st} \quad . \tag{19}$$

Stem factor at static TST, DP TST, and at required closing thrust—Stem factor is calculated as follows:

$$SF = TQ_t/F_t \quad . \tag{20}$$

Torque switch margin—The torque switch (TS) margin is the difference between the TS thrust setting and the thrust required to close the valve, expressed in terms of pounds of thrust and percentage, shown as

$$TSM_{Th} = F_{tst/dp} - F_{r,t} \quad ; \tag{21}$$

$$TSM_{\%} = TSM_{Th}/F_{r,t} \quad . \tag{22}$$

Capability margin—The capability margin is the difference between the load carrying capability of the limiting component and the required thrust to close the valve (determined above), expressed in terms of pounds of thrust and percentage, shown as

$$CM_{Th} = LC - F_{r,t} \quad ; \tag{23}$$

$$CM_{\%} = CM_{Th}/F_{r,t} \quad . \tag{24}$$

The following information describes the process for the opening stroke:

Required thrust and torque—This is the maximum thrust and corresponding torque required by the actuator to fully open the valve. This thrust will occur either at unseating or where dP load is highest.[f] Required thrust and torque are determined using the same equations presented for the closing stroke.

dP load—This is the load that will be imposed on the valve resulting from the differential pressure effect and is determined as

$$F_{dp,t} = F_{r,t} - F_{pack,t} + F_p - F_u \quad . \tag{25}$$

Piston effect load—This load is determined the same as identified for the closing stroke.

Packing load—The packing load is determined the same as identified for the closing stroke.

Unseating load—This is the force, beyond that required to overcome dP, that is required to unwedge the disc from the seat (applicable to gate

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f. For the case where the unseating load is the highest load seen during the opening stroke, extrapolation of the required trust may not be accurate if the dP test is performed at a significantly lower pressure than the design basis condition. This is due to the effect of increasing dP, which helps to unseat the valve as the upstream pressure becomes greater. If the unseating force is extrapolated, then an artificially high required opening thrust at design-basis conditions may result. Therefore, when the dP test is performed at less than approximately 90% of the design-basis condition, the required opening thrust may be determined by extrapolating the maximum dP effect force (even if lower than the unseating force) and adding an appropriate term into the equation to consider the effect of unseating. This unseating term should be determined using engineering judgment, based upon static test results, when possible.

valves only). The unseating load is determined from the diagnostic trace as

$$F_u = F_{u,t} - F_{t,maxdp} \quad . \tag{26}$$

Seat friction factor (valve factor)—The seat friction factor is determined using the same equation as presented for the closing stroke.

Stem factor at maximum required opening thrust—Calculate the stem factor at this point using the same equation presented for the closing stroke.

Capability margin—The capability margin is the difference between the load carrying capability of the limiting component and the required thrust to open the valve, expressed in terms of pounds of thrust and percentage. The margin may be calculated using the same equations as presented for the closing stroke.

Globe Valve Reconciliation

The following information describes the process for the closing stroke:

Required thrust/torque[g]—This is the thrust and corresponding torque required to close the orifice (i.e., when the disc wedges into the seat or at the point of greatest dP load), whichever is greater. Required thrust and torque (at the calculation design basis pressure) are determined using the same equations as presented for the gate valve closing stroke.

Packing load—The packing load is determined the same as identified in the gate valve reconciliation section.

Load sensitive behavior (rate of loading)—Load sensitive behavior may be determined using the same equation presented for the gate valve closing stroke.

Stem factor—Stem factor is calculated at each of the following points: static TST, DP TST, and at the required closing thrust. The stem factor may be calculated using the same equation presented for the gate valve closing stroke.

TS margin—The torque switch margin may be calculated using the same equations presented for the gate valve closing stroke.

The following information describes the process for the opening stroke:

Required thrust/torque[h]—This is the maximum thrust and corresponding torque required **by the actuator** to fully open the valve. This thrust will occur either at unseating or where dP load is highest. Required thrust and torque may be determined using the same equations presented for the gate valve opening stroke.

Packing load—The packing load is determined the same as identified in the gate valve reconciliation section.

Stem factor at maximum required opening thrust—Calculate the stem factor at this point by dividing the measured torque by the measured thrust. The equation is the same as provided for the gate valve closing stroke.

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g. Globe valves with flow over the seat may have lower thrust requirements in the closing direction as a result of flow effects. This should be considered when extrapolating test results to a design-basis condition that differs from the test condition. For example, the required thrust to close a globe valve with flow over the seat may be less at design basis dP than at a lower test dP. The cognizant engineer responsible for the reconciliation process must be able to recognize this condition and adjust the reconciliation process, as required.

h. Globe valves with flow under the seat may have lower thrust requirements in the opening direction due to flow effects. This should be considered when extrapolating test results to a design basis condition which differs from the test condition. For example, the required thrust to open a globe valve with flow under the seat may be less at design basis dP than at a lower test dP. The cognizant engineer responsible for the reconciliation process must be able to recognize this condition and make adjustments to the process, as necessary.

Capability margin—The capability margin is the difference between the thrust capability of the limiting component and the required thrust to open the valve, expressed in terms of pounds of thrust and percentage. The margin may be calculated using the same equations as provided for the gate valve opening stroke.

RECONCILIATION RESULTS

Figures A-1 through A-17 in the Appendix depict the results of reconciliations performed to date at TVA. It should be noted that the purpose of reconciliation is to identify trends and take a "big picture" look at the adequacy of TVA's MOV thrust and torque calculation methodology. It is sometimes difficult to form conclusions based on individual data points because of the uncertainty and subjectivity associated with evaluation of the test results. TVA dispositions reconciliation results that indicate potential problems with the calculation methodology in the following manner:

1. Where the reconciliation process indicates potential capability or setup problems with a particular MOV, an engineering evaluation is performed for the affected valve to ensure that the valve is capable of performing its design function. Corrective actions are identified and implemented when necessary. When appropriate, thrust and torque calculations are revised to reflect the test results.

2. Following the valve-specific review, the potential issue is reviewed for generic applicability to other MOV applications, especially those for which a dP test at design-basis conditions is not possible. Corrective actions are specified, when appropriate.

3. Reconciliation results are also evaluated programmatically to ensure that lessons-learned from testing are used to update the TVA MOV thrust and torque calculation methodology.

The overall TVA calculation methodology for determining MOV thrust requirements has been conservative in most cases. There have been instances where individual factors within a given equation have not been conservative; however, the overall equation has still contained enough conservatism to envelope these higher individual factors. For example, the seat coefficient of friction may have been calculated to be 0.6 based upon test results (instead of the 0.4 assumed by the TVA equation), but the thrust required to operate the valve was still bounded by the equation.

One change has been made to the TVA MOV calculation methodology based upon observed test data. In several instances, the calculated unwedging load was compared with test results and the calculated results were overly conservative. In order to predict unwedging loads more accurately, TVA contracted Siemens Power Corporation to perform a finite element stressanalysis on a 300-lb, 12-in. Walworth solid wedge gate valve. This analysis demonstrated a reduction in the unwedging factor in relation to opening differential pressure. Figure 5 shows the relationship between the wedging factor (f_w), the closing thrust F_k, and the required thrust to overcome opening differential pressure F_{dp}. Figure 5 also shows that for a F_{dp}/F_k ratio of 0.4 or greater the wedge factor can be 0.6 for solid wedge gate valves. If the F_{dp}/F_k ratio is less than 0.4, the unwedging factor can be computed by the following relationship: $f_w = 1 - F_{dp}/F_k$. In many cases the test results show that the differential pressure load during opening is a separate load and should not be added to the unwedging load, as the present methodology requires. TVA is continuing to review additional test results from our nuclear plants and the EPRI PPP information to verify that these loads should not be additive.

TVA has also revised its methodology as additional information is received from the EPRI PPP. These changes resulted in a higher friction factor being used for Borg-Warner gate valves and a distinction being made between seat and guide based globe valves when determining the maximum area that dP would act against.

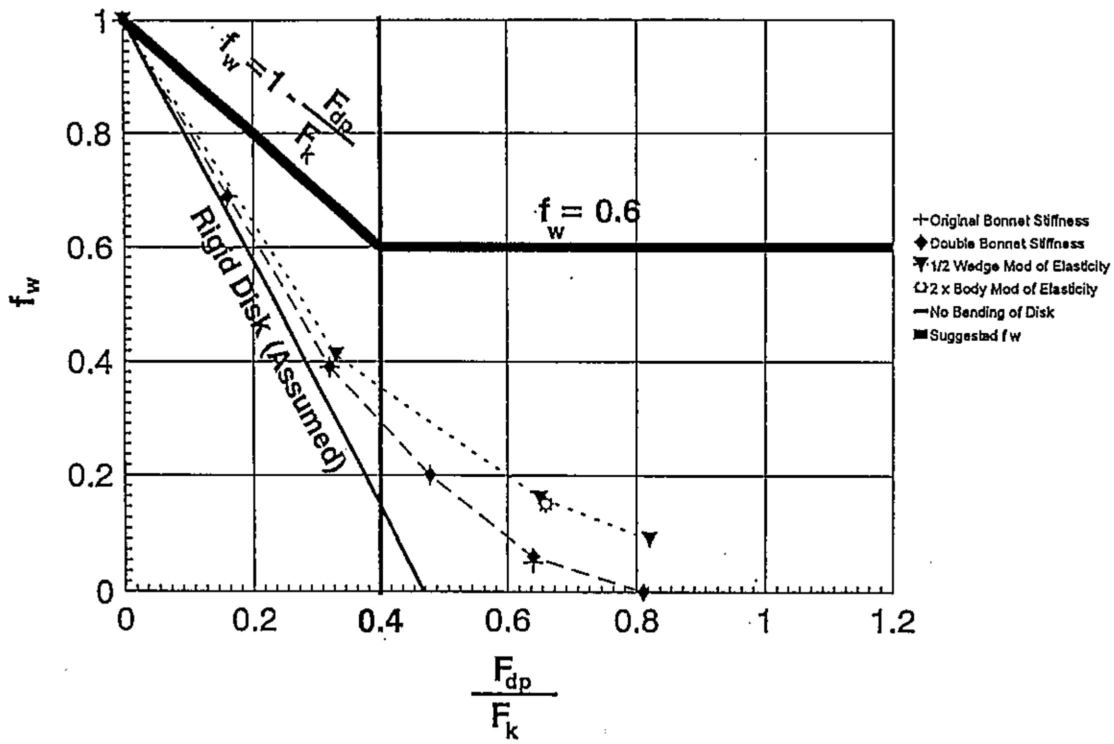

Figure 5. Suggested wedge factor f_w for solid wedge gate valves.

Appendix A

TVA Gate and Globe Valve Reconciliation Charts

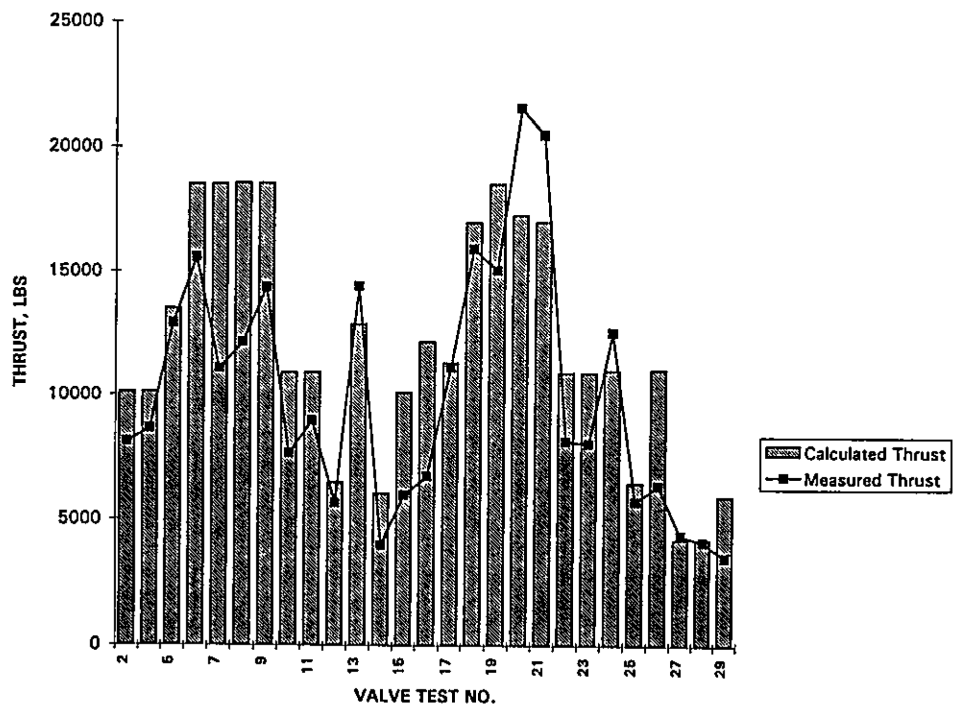

Figure A-1. Gate valve closing thrust.

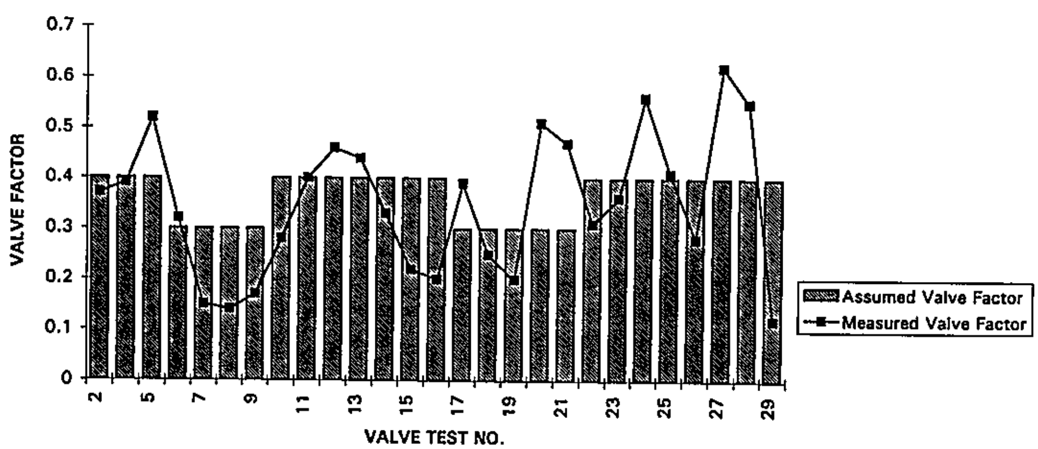

Figure A-2. Gate valves, valve factor—closing thrust.

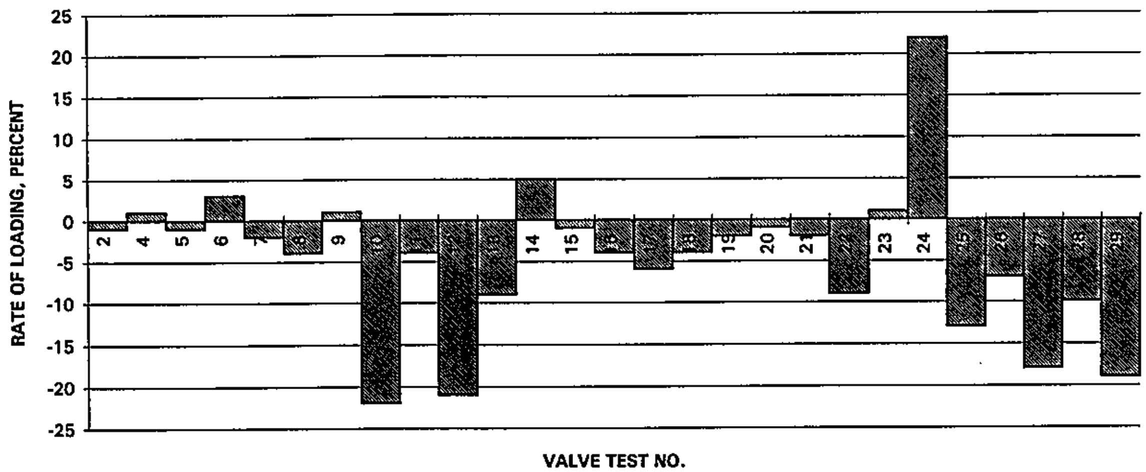

Figure A-3. Gate valve rate of loading.

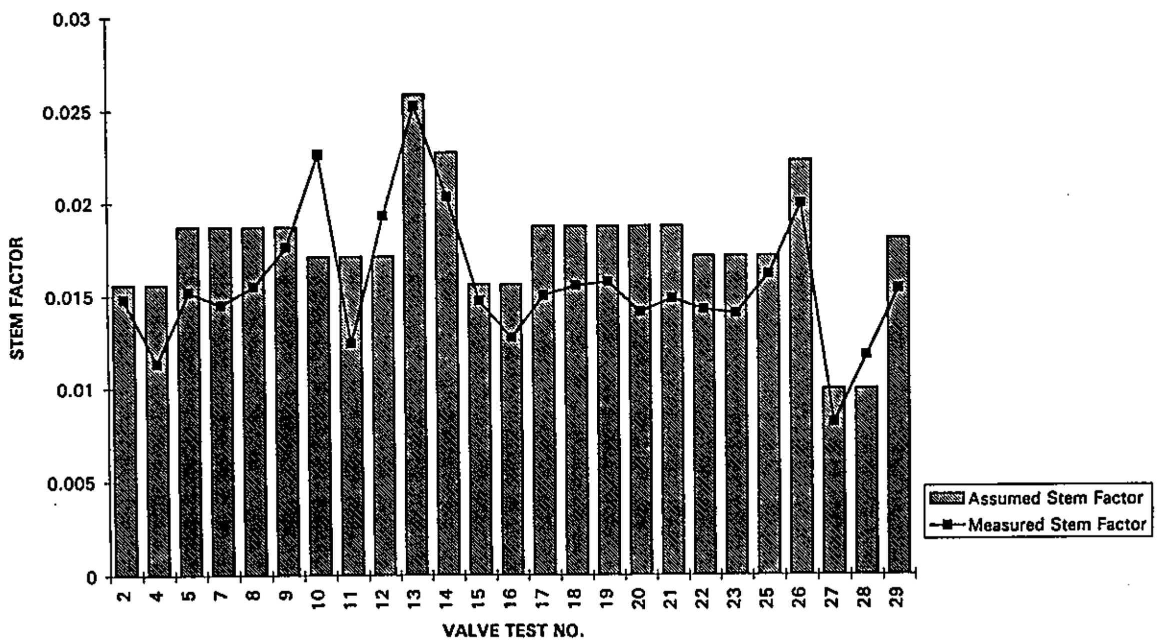

Figure A-4. Gate valve stem factors—closing stroke.

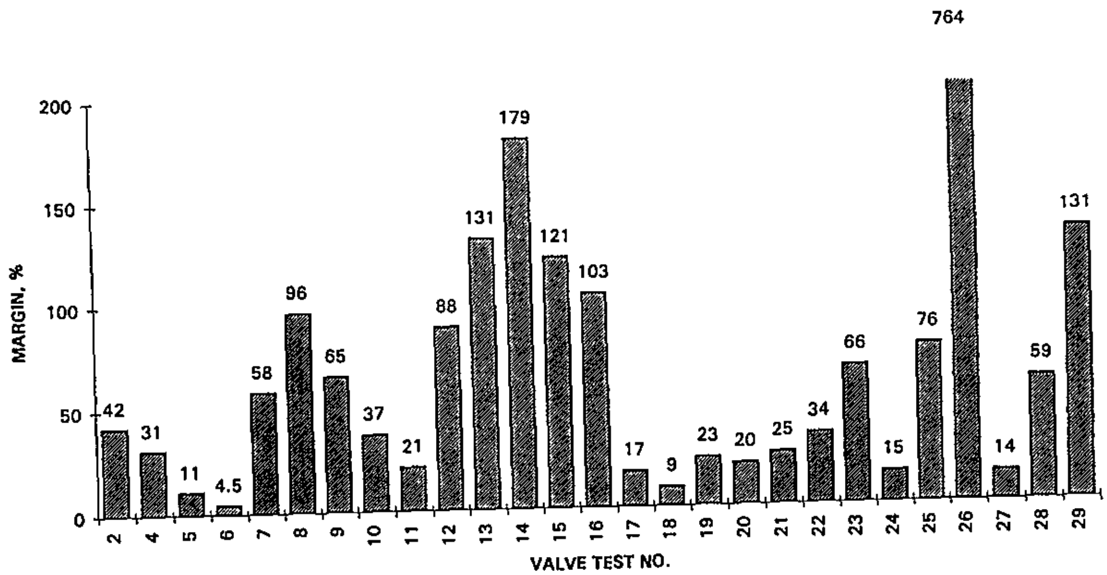

Figure A-5. Gate valve torque switch margin—closing stroke.

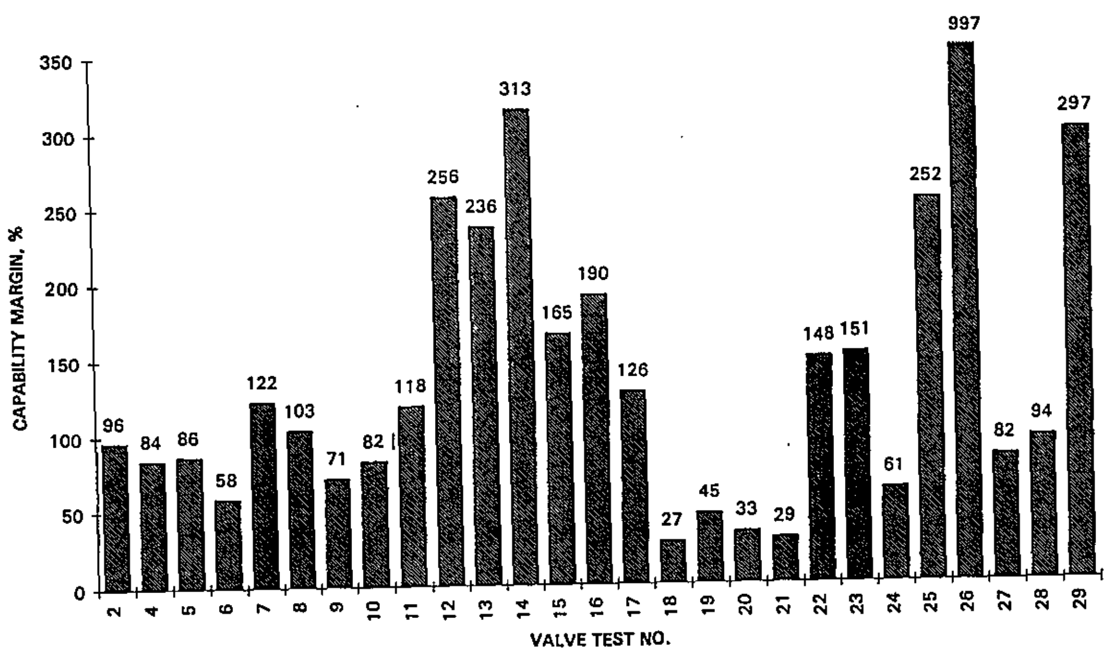

Figure A-6. Gate valve capability margin—closing stroke.

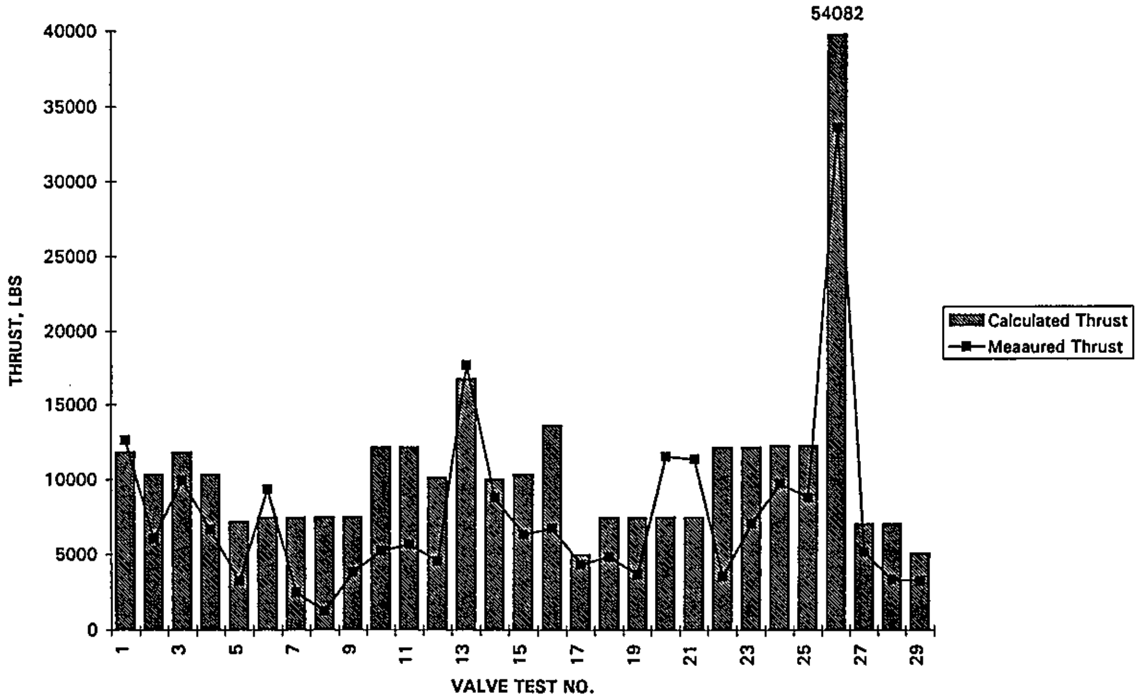

Figure A-7. Gate valve opening thrust.

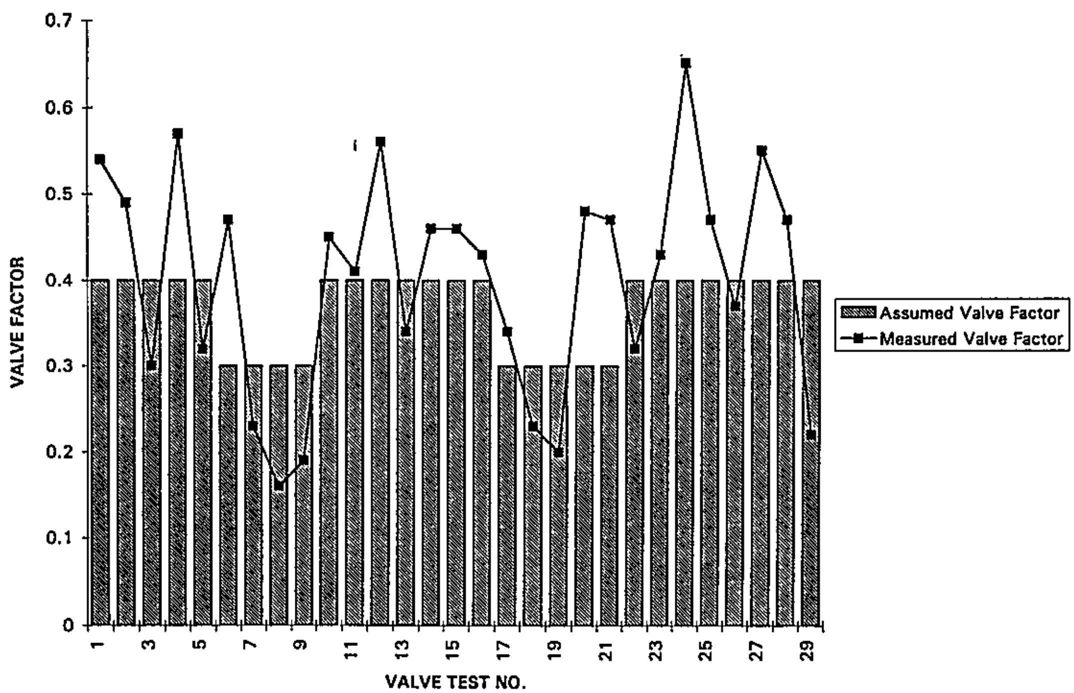

Figure A-8. Gate valve factor—opening stroke.

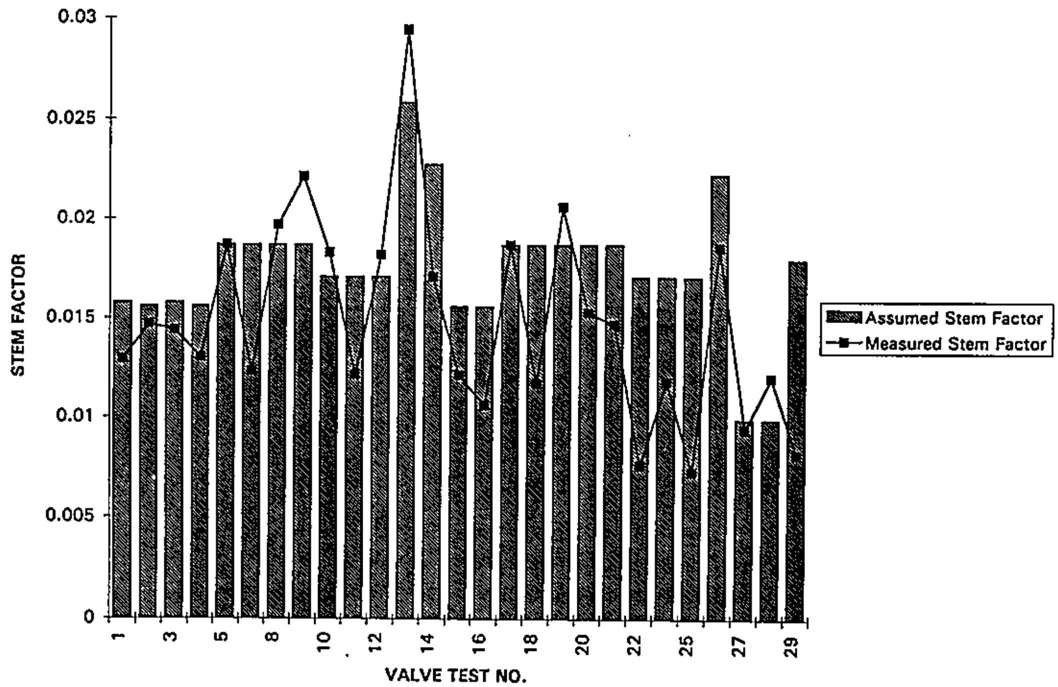

Figure A-9. Gate valve stem factor—opening stroke.

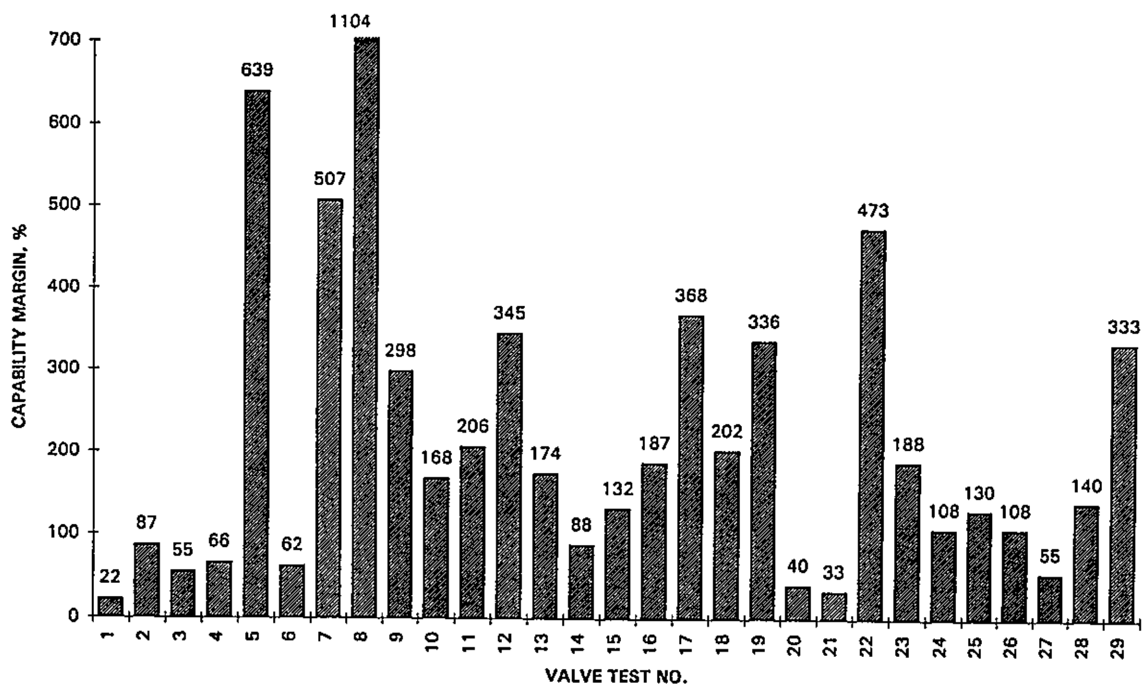

Figure A-10. Gate valve capability margin—opening stroke.

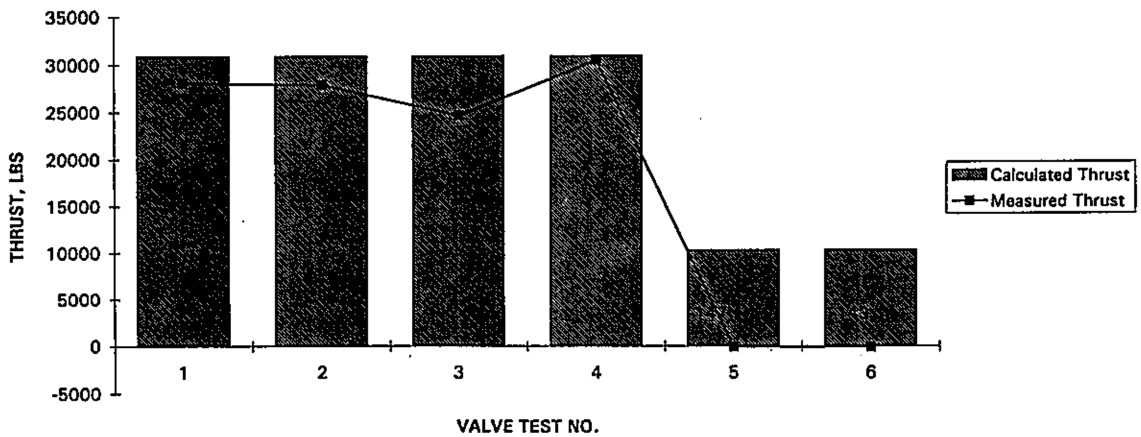

Figure A-11. Globe valve closing thrust.

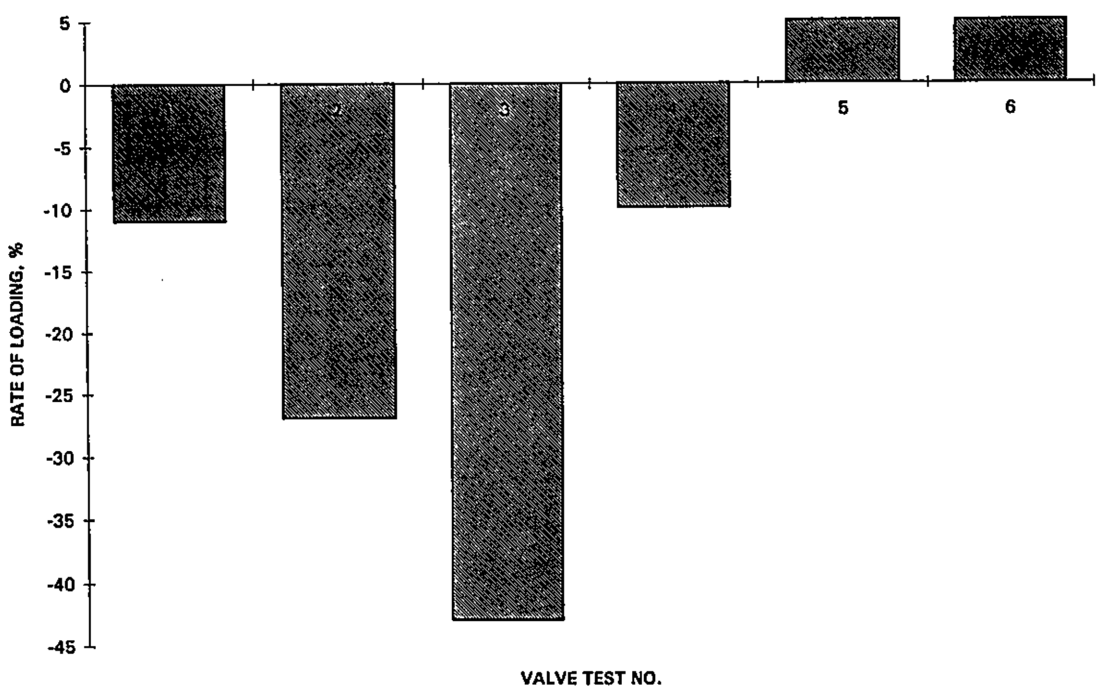

Figure A-12. Globe valve rate of loading—closing stroke.

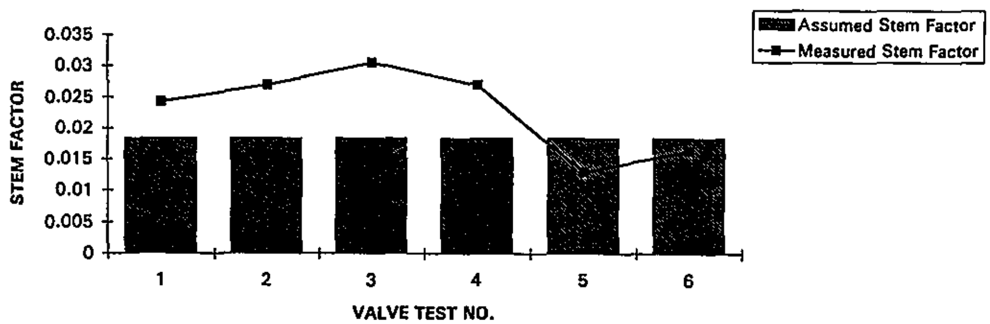

Figure A-13. Globe valve stem factor—closing stroke.

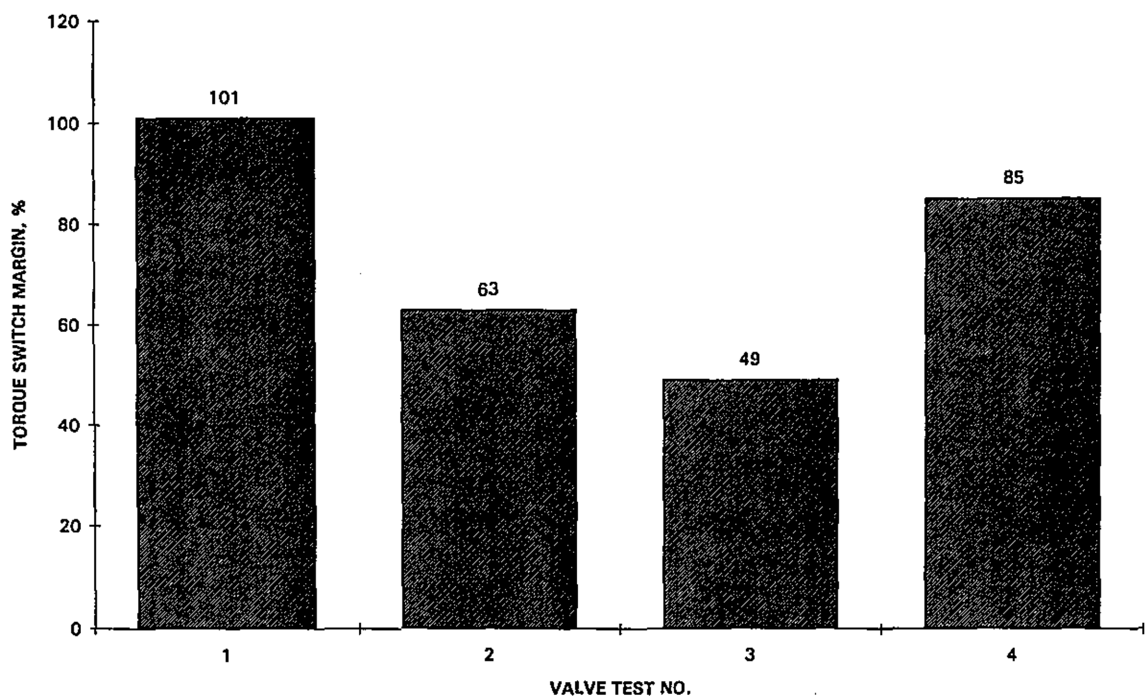

Figure A-14. Globe valve torque switch margin—closing stroke.

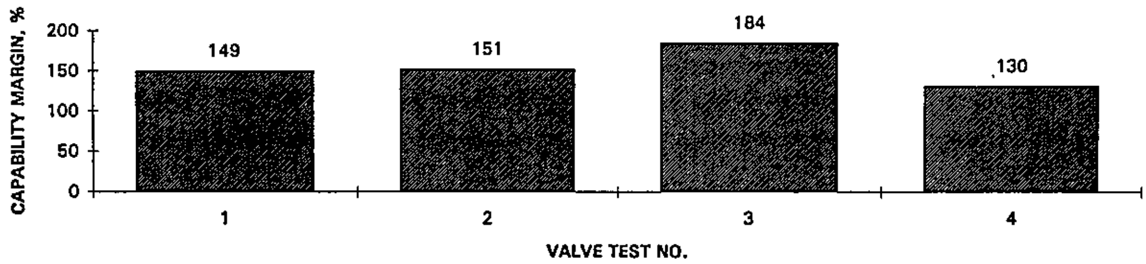

Figure A-15. Globe valve capability margin—closing stroke.

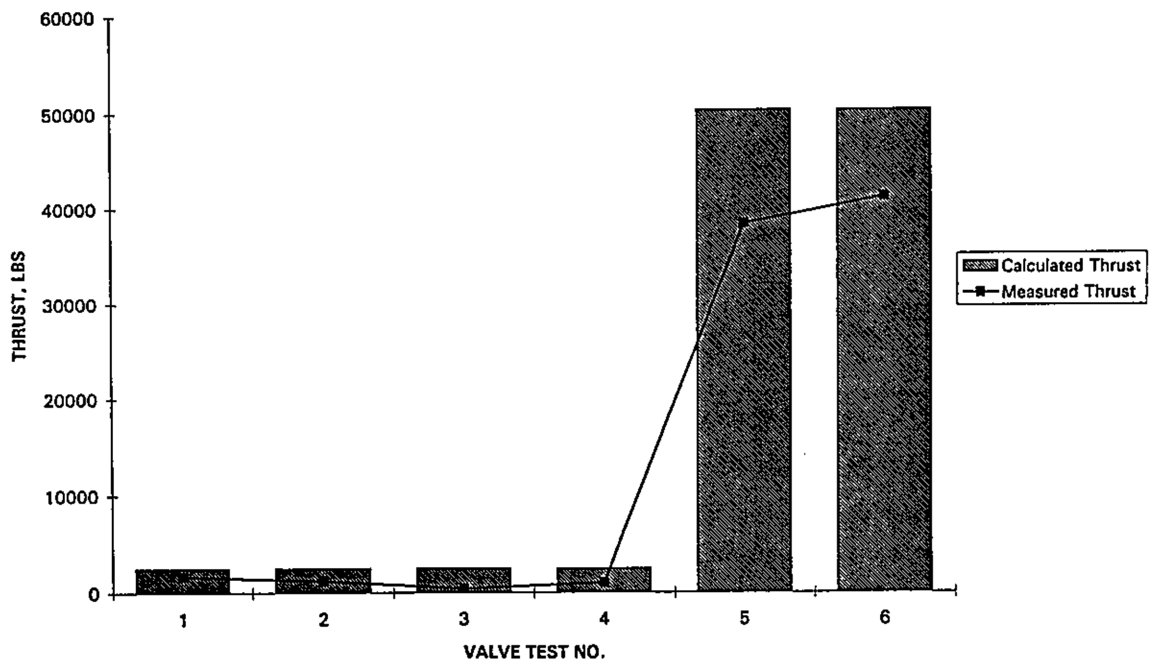

Figure A-16. Globe valve opening thrust.

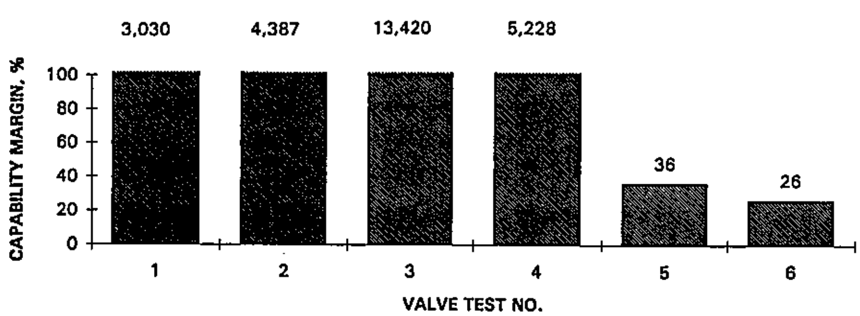

Figure A-17. Globe valve capability margin—opening stroke.

Nonintrusive Stroke Timing and Diagnostic Testing of Solenoid-Operated Valves

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ABSTRACT

In some cases, for solenoid-operated valves (SOVs) that are required to conform to the Section XI, Paragraph IWV-3413(b) of the American Society of Mechanical Engineers Code, power-operated valve stroke timing requirements cannot be stroke timed using conventional methods because of a lack of electrical or mechanical position indicators. A nonintrusive stroke timing and diagnostic test technique, based on monitoring coil current through inductive principles, was developed for rapid acting, ac-powered, rectified coil SOVs. The technique can accurately measure valve stroke time during plant system operation without intrusion into plant electrical systems. Examples of field test data and laboratory bench-top test data will be discussed for ac-powered, rectified coil, direct-acting and pilot-operated SOVs. Similar methods for testing dc SOVs will also be discussed.

INTRODUCTION

In many applications, solenoid-operated valves (SOVs) in U.S. nuclear power plant safety systems must be tested in accordance with "Rules for Inservice Inspection of Nuclear Plant Components," Section XI, Paragraph IWV-3413(b) of the American Society of Mechanical Engineers (ASME) Code. The ASME Code requires power-operated valves to be stroke timed to the nearest second on a quarterly basis. The intent of this testing is to verify component operability and to detect degradation. Excellent discussions on SOV degradation and the significance of SOV failures in nuclear power plant applications can be found in reports by Bacanskas et al. (1987), Kryter (1992), Ornstein (1991), and Holzman (1992).

A commonly used method for SOV stroke time measurement is performed by visually monitoring SOV position indicators and measuring stroke time with a stopwatch. This method is not accurate for rapid-acting valves with stroke times of 2 seconds or less. The SOV stroke times encountered during this research were typically less than 100 milliseconds (ms). One manufacturer of common nuclear-grade SOVs does not recommend stopwatch methods to verify stroke times from valves that stroke in less than 300 ms (Ferrarese, 1992).

In some instances, SOVs that are required to conform to ASME Section XI power-operated valve stroke timing requirements lack electrical or mechanical position indication and, consequently, cannot be stroke timed using conventional methods. The U.S. Nuclear Regulatory Commission has emphasized the intent of the Section XI testing requirements in response to relief requests from several commercial U.S. nuclear power plants who, in some cases, had no means to measure SOV stroke time because they lacked position indication. Since design changes and modifications to actuation systems or valves, solely to facilitate stroke timing, would be burdensome, utilities were advised to develop a means to measure stroke time in order to monitor valve degradation.

Because of these necessities, a nonintrusive test method based on monitoring coil current through inductive principles was developed. This

method can accurately and repeatably measure SOV stroke time, in milliseconds, during coil energization and deenergization. Examples of both field test data and laboratory bench-top test data will be discussed for ac-powered, rectified-coil, direct-acting and pilot-operated SOVs. Similar methods for testing dc SOVs will also be discussed.

A NONINVASIVE TEST PHILOSOPHY

Before the nonintrusive SOV testing method was developed, it was decided that SOV testing should be performed in the most noninvasive manner possible and that SOV test data should be obtained during actuation of the SOV during plant system operation. Whenever possible, SOV testing was to be performed in conjunction with previously scheduled quarterly testing of power plant systems in order to minimize impact on plant operations. For testing purposes, plant system operation produced the required SOV changes of state. The technique discussed in this paper uses external sensors physically located at the valve, which eliminates intrusion into plant electrical systems.

The Oak Ridge National Laboratory (ORNL) focused initial attention and efforts on remotely applied methods that did not require physical access to the SOV or the addition of sensors or signal wires in order to detect SOV degradation (Kryter, 1992). While these methods have merit, the author disagrees that sensors temporarily mounted external to a SOV constitutes an intrusive form of testing. The method discussed in this paper is simple to apply and offers the advantage of not requiring intrusion into plant electrical systems, either through direct wire connections or clamp-on devices.

NONINTRUSIVE STROKE TIME MEASUREMENT OF AC SOVS

The short duration of a valve actuation event, typically measured in milliseconds, predicated the use of a data recording instrument or analog to digital conversion device to ensure capture of test data during plant system operation. The use of a digital audio tape (DAT) recording device in this study allowed post processing and analysis with a personal-computer-based data acquisition and digital signal processing system and other instrumentation.

Sensors

One or more accelerometers were positioned on an SOV in order to monitor structure-borne noise in the audible frequency range between approximately 20 and 10,000 Hz. The resulting acoustic signatures were analyzed using time domain techniques to identify impacts caused by SOV internal parts during opening and closing. Analysis of these impacts provided, at a minimum, a time point of opening or closing at a particular sensor location.

An additional sensor was required that could, at a minimum, provide a time point indication of solenoid energization and deenergization. Valve stroke time could then be measured between the time point of energization or deenergization and the time point of opening or closing impact. Because changes in the magnetic field produced by the solenoid coil occur upon energization and deenergization, and plunger travel, an inductive sensor was used to monitor coil current from the exterior of the solenoid coil housing.

Inductive sensors consist of a coil of very fine wire windings, with thousands of turns, surrounding a metal core and an air-gap. The magnetic flux produced by current flow in the solenoid coil induces a current in the sensor. A voltage output proportional to the induced current can then be measured. Inductive sensors differ from conventional current measuring devices, such as toroids and current transformers, in that they use an air-gapped high permeability core to increase the linear response range and minimize nonlinear saturation effects (Smith, 1988). Inductive sensors also differ from Hall-effect probes in that they are inexpensive and self-driving, requiring no auxiliary power or signal conditioning.

Field tests were performed on several ac-powered SOVs in the energized state to select a sensor most suited to measuring current from the flux level present on the exterior of a solenoid coil housing. A sensor with a coil consisting of 25,000 wire turns was selected. Proper location and orientation of the inductive sensor was initially determined by measuring sensor output levels with an oscilloscope at various positions on the solenoid coil housing. Inductive sensor measurements taken on the exterior of the solenoid coil housing of ac-powered, rectified-coil SOVs revealed that a 120-Hz sine wave is present while the solenoid coil is energized. The 120-Hz sine wave results from the 60-Hz line frequency current passed through a full-wave bridge rectifier inside the valves' circuitry.

Stroke Time Measurement

Accelerometers were temporarily mounted to the valve body or solenoid coil housing. The accelerometers were either stud mounted to adhesive pads that had been affixed with epoxy or magnetically mounted with high-strength magnetic bases. The inductive sensor was properly oriented and temporarily strap mounted to the outside of the solenoid coil housing. The accelerometer was connected to a power supply and then to the input of a DAT recorder, and the inductive sensor was connected directly to the input of the DAT recorder. Test data were recorded as the valve actuated (both energized and deenergized) during normal plant system operation. Test data were then played back and processed using a personal computer with data acquisition and digital signal processing capabilities.

The resulting inductive current time traces were displayed, along with the acoustic time traces, so that stroke time measurements could be made using the time point of energization, or deenergization, and the time point of impact of the valve internals detected during the opening or closing cycle. Opening and closing data collected from a direct-acting SOV in nuclear service are shown in Figures 1 and 2.

Analysis of raw time waveforms obtained via an externally mounted inductive sensor and accelerometer allowed measurement of ac SOV stroke time. This method was capable of accurately and repeatably measuring SOV stroke time, in milliseconds, during coil energization and deenergization. Expanded time traces are shown in Figures 3 and 4. Cursors mark time positions of coil energization or deenergization and opening or closing impacts. Opening stroke time was 26 ms, and closing stroke time was 84 ms.

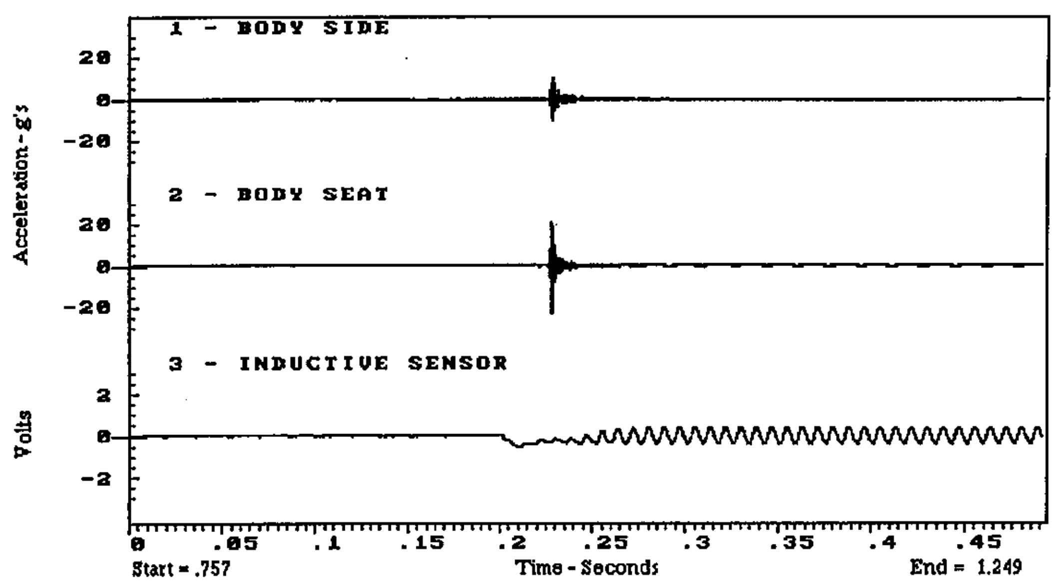

Figure 1. Direct acting SOV opening—accelerometer and inductive sensor traces.

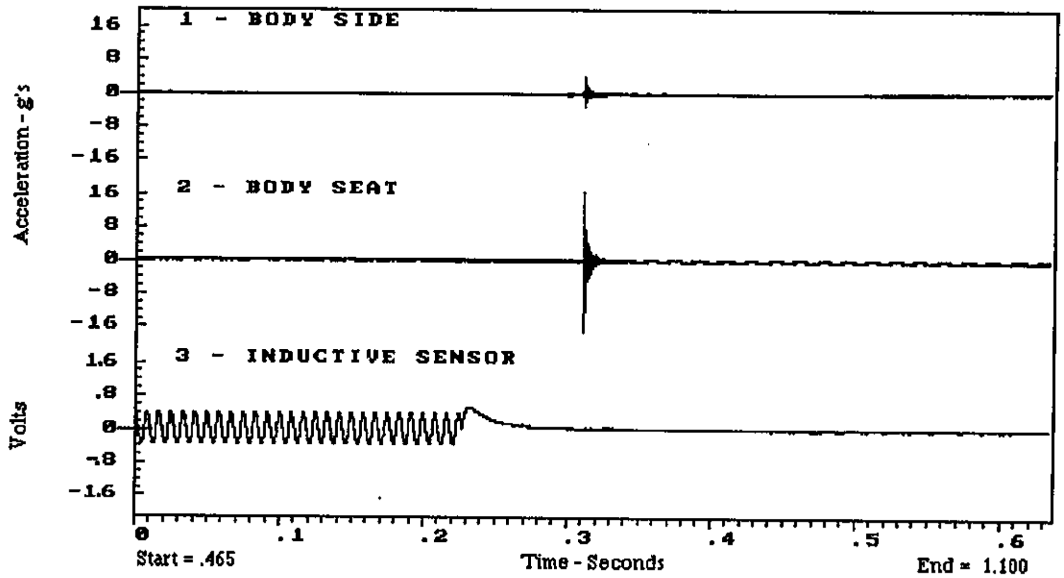

Figure 2. Direct acting SOV closing—accelerometer and inductive sensor traces.

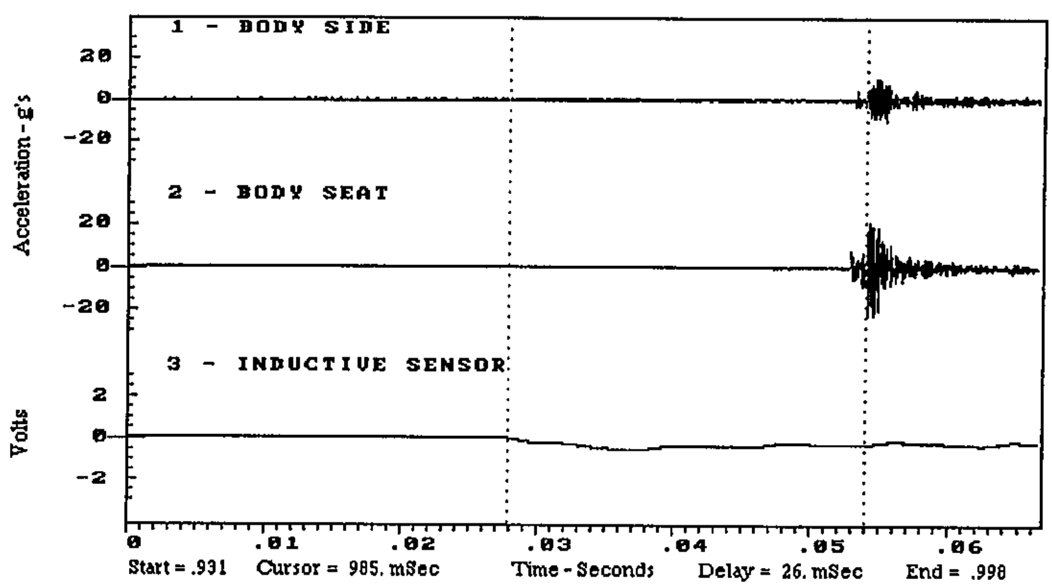

Figure 3. Direct acting SOV opening—stroke time measurement.

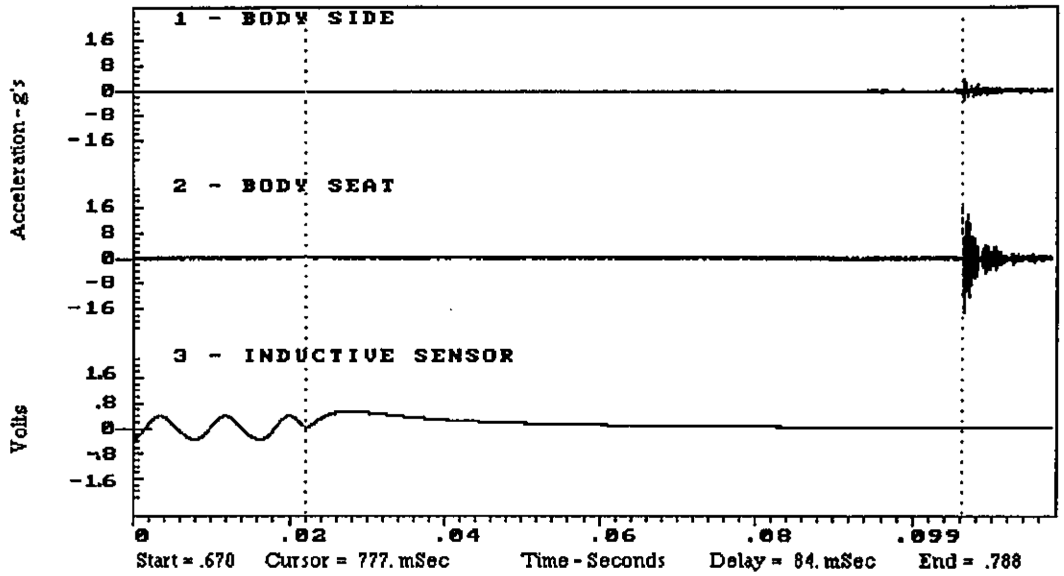

Figure 4. Direct acting SOV closing—stroke time measurement.

Limitations

Measurement of SOV stroke time from raw inductive current traces and accelerometer signals requires some level of interpretation by the user. High levels of background noise, piping vibration, or flow noise can complicate location of opening or closing transients in accelerometer time signatures. Accelerometers also require additional power supplies or signal conditioning, as well as additional data recording channels. However, accelerometer signatures have merit and can be used to detect impacting, binding, chatter, and spurious openings and closings of SOVs. Raw ac current signals induced by the solenoid coil can contain 60 Hz contamination from stray electrical fields. In addition, ac current signals are strongly harmonic, which can make detection of subtle changes difficult.

IMPROVEMENTS

The interaction of a solenoid coil and an inductive sensor coil is analogous to a amplitude modulation (AM) transmitter coil and a receiver coil, with the solenoid coil acting as the transmitter and the inductive sensor coil acting as the receiver. The information of interest, measured by the inductive sensor, is the variation in amplitude, or amplitude modulation, of the 120-Hz carrier signal resulting from the 60-Hz line frequency passed through a full-wave rectifier circuit inside an SOV. While the raw inductive trace data, coupled with accelerometers, can be extremely useful in stroke time measurement and diagnostics, as described above, further signal processing provided a much clearer indication of solenoid coil energization or deenergization.

Through demodulation processing, the inductive sensor current waveform alone can be used to determine valve stroke time during coil energization. The demodulated trace is a representation of the coil's dc current, which is dependent on both plunger position and velocity and can be analyzed to detect degradation.

Demodulation of Inductive Sensor Current Signatures

The process for separating the time varying signal of interest, in this case the coil current, from the 120-Hz carrier signal is known as amplitude demodulation, or root mean square to direct current (RMS to dc) conversion. Amplitude demodulation is commonly used in vibration analysis of gears and rolling element bearings,

and more recently in time and frequency domain analyses of ac induction motor current.

Amplitude demodulation involves two signal processing techniques: enveloping and filtering. Enveloping is the process of rectifying the carrier signal, that is making all negative peaks positive. Enveloping can be achieved through the use of an analog full-wave rectifier circuit or digitally through the use of the Hilbert transform (Thrane, 1984). Filtering can be achieved through the use of either analog filters or digital filtering techniques. Zoom fast Fourier transform (FFT) followed by inverse FFT techniques could also be used to filter digital data effectively.

In this research, analog high pass filtering was applied to incoming current signals, prior to the enveloping process, in order to remove offending signals, such as 60-Hz contamination from motors. An analog full-wave rectifier circuit was then applied, followed by analog low pass filtering to remove higher frequency data, such as the 240 Hz sine wave produced by rectifying the 120 Hz coil current signal in the first part of the demodulation process and other harmonics. Raw and demodulated inductive sensor signals plotted against time from a direct-acting SOV opening (energizing) event are shown in Figure 5.

DESCRIPTION OF SOV CURRENT TRACES

The movement of the SOV plunger assembly has a feedback effect, or back electromotive force (EMF), on the coil current. The inductive trace measured during SOV coil energization can typically be divided into three events: energization point and inrush current, increase to steady-state current, and steady-state operating current.

The ac coil current with the plunger fully withdrawn, often called inrush current, is considerably greater than the value with the plunger inserted against the stop. This occurs because an ac coil has a much lower impedance when the plunger is fully withdrawn. The inrush current for typical ac solenoid coils ranges from one and one-half to three times the steady-state coil current (Holzman, 1992). Immediately following the application of voltage to the SOV coil, the current increases rapidly to the inrush current level. After the magnetic force begins to move the plunger toward the core, the current decreases. When the plunger reaches the end of stroke and stops, the current then increases until it reaches the steady-state holding current level.

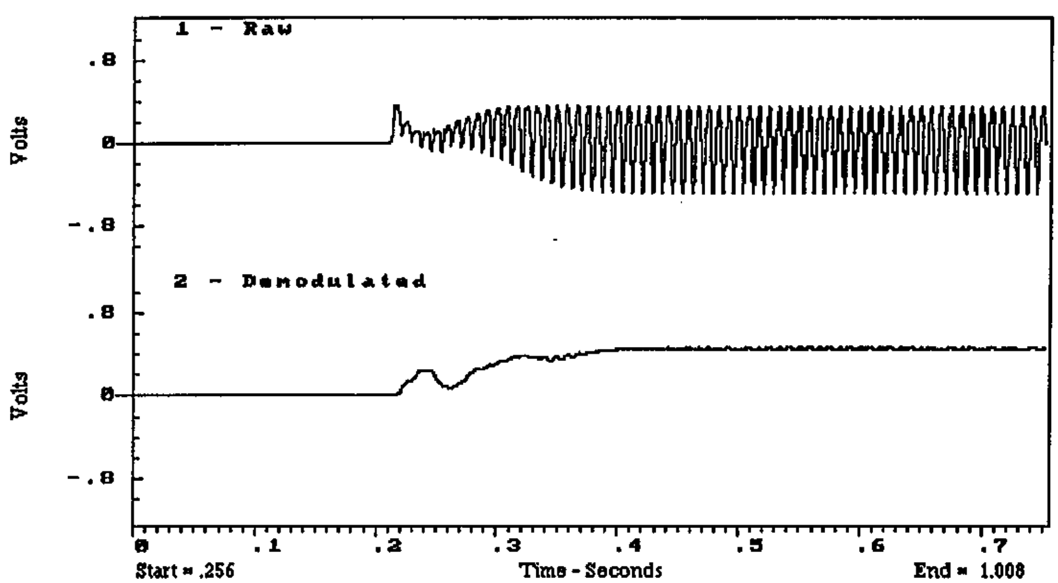

Figure 5. Direct acting SOV opening—raw and demodulated inductive traces.

If something prevents the plunger from fully inserting, the lower impedance will cause the coil to draw excessive current. The current level will be somewhere between the inrush and holding current values, depending on the relative plunger position (Holzman, 1992).

LABORATORY EXPERIMENTS

Bench-top experiments were performed on a direct-acting Valcor SOV. The valve body and plunger were modified to accept a cable connected to a lanyard potentiometer, which produced a voltage output proportional to the linear position of the plunger. An inductive sensor was strap mounted to the exterior of the solenoid coil housing, and accelerometers were magnetically mounted to the valve body.

Test data were recorded during valve energization using a DAT recorder through a series of trials. Analog filters and full-wave rectifier circuitry were applied to demodulate the valve's coil current signal, as measured by the inductive sensor. Demodulated inductive sensor traces were compared with valve plunger position traces obtained from the lanyard potentiometer output signals.

A plot of plunger travel and demodulated inductive sensor output versus time, obtained during the opening of a direct acting SOV, is shown in Figure 6. The point at which power was applied and the coil's magnetic field began to grow is labeled as Point 1. The coil current continued to increase in amplitude until Point 2, where the plunger began to move. Plunger motion into the core produced a back EMF and a decrease in coil current until the end of stroke was reached at Point 3. Coil current then increased in amplitude until reaching the steady-state holding current level at Point 4.

Test results showed that output from the demodulated inductive sensor yields enough information to measure valve stroke time independent of accelerometer traces during energization events. A direct-acting SOV's stroke time measurement obtained directly from the demodulated inductive sensor trace is shown in Figure 7. The energization and end of stroke time points are indicated in the figure with dotted lines. The time measured between these two events showed valve stroke time to be 47 ms.

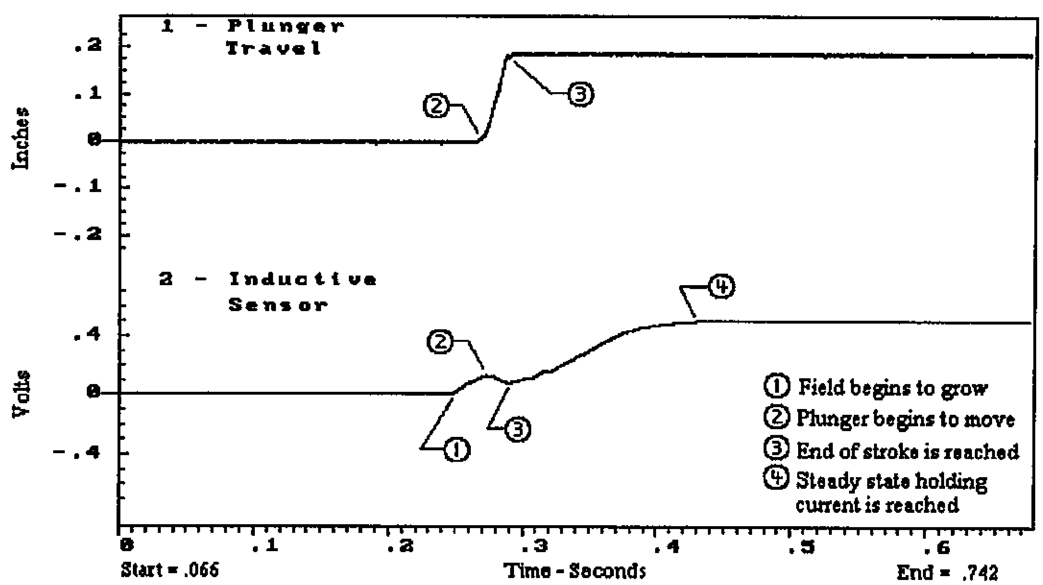

Figure 6. Direct acting SOV opening—plunger travel and inductive traces.

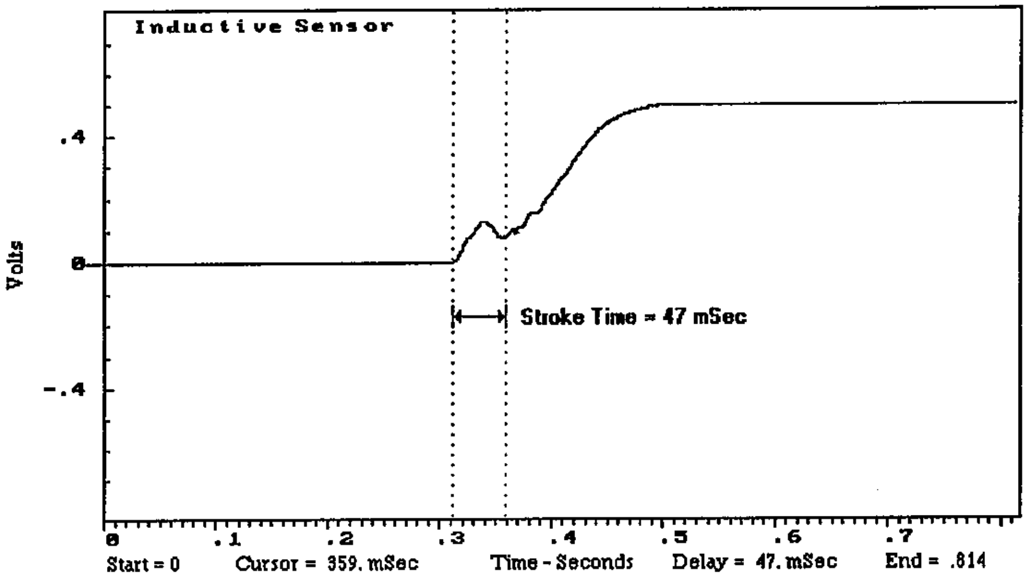

Figure 7. Stroke time measurement from demodulated inductive trace.

DETECTION OF SOV FAULTS

Once the coil current dynamics of a properly functioning SOV are understood, anomalies caused by SOV faults can be detected. Analysis of demodulated inductive sensor traces, which are representations of SOV coil current, yields information that can be used by an analyst to determine the condition of an SOV. Because plunger motion can be observed as a result of its effects on coil current, binding of valve internals or abnormal events, such as spurious openings, should become evident. Holding current level is dependant on plunger insertion position and could be trended to detect whether an SOV's capability to fully open or close has been affected.

The closing (energization) of a pilot-operated Target Rock SOV in nuclear service was monitored, using accelerometers in conjunction with inductive sensors, and analyzed. A plot of acceleration, measured on the SOV's coil housing, and demodulated inductive sensor output versus time are shown in Figure 8. The pilot disk to main disk impact, Point 1 in the figure, could be discerned in both the accelerometer and demodulated inductive sensor traces. The main disk closing impact occurred at Point 2. A waterhammer event began at Point 3. Disk impacts and their related disturbances to the coil current can be seen at Point 4. Following the impacts, just after Point 4, plunger motion can be seen as a decrease in coil current. The final steady-state holding current level was reached near Point 5. This holding current amplitude was slightly higher than the holding current amplitude that had previously been reached between Points 1 and 4, suggesting that the plunger may have jammed following the waterhammer event and may not have fully inserted. Slight current deviations were also observed following Point 5, which coincided with the second set of high-amplitude impacts shown in the accelerometer trace.

STROKE TIME TESTING OF DC SOVS

Methods and equipment for stroke time measurement and diagnostics of dc-powered SOVs have also been investigated, although no experimentation has been conducted on dc SOVs by the author.

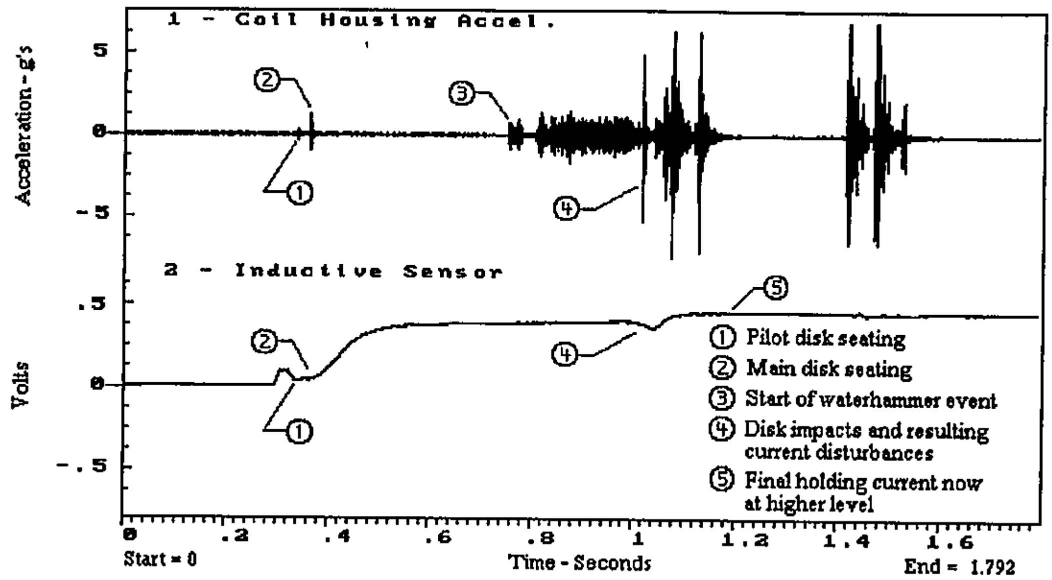

Figure 8. Pilot operated SOV closing—accelerometer and inductive traces.

Effective stroke time test and diagnostic data may also be collected from dc-powered SOVs in a nonintrusive manner. To measure magnetic flux, dc SOV test data could be collected with the substitution of a Hall-effect device and a gaussmeter for the ac inductive sensor. The demodulation techniques discussed previously would not be necessary because no harmonic oscillations would be present in the dc data other than those resulting from stray electric fields. Contamination at 60-Hz line frequency, from ac induction motors and such, could be effectively filtered out prior to data recording. While a harmonic-free dc signal simplifies the signal processing requirements, dc testing would require the use of one additional field instrument, the gaussmeter. Hall-effect probes and gaussmeters are also relatively expensive compared with ac inductive sensors.

CONCLUSIONS

This paper discussed the demonstration of a nonintrusive test method using readily available and inexpensive sensors and instrumentation for stroke time measurement and diagnostic testing of rapid-acting, ac-powered, rectified-coil solenoid-operated valves. Inductive sensors allowed monitoring of solenoid coil current external to a valve without requiring intrusion into the plant electrical system. Accelerometers proved useful in conjunction with coil current traces to provide valve deenergizing stroke times, as well as to help detect abnormal impacting of SOV internal parts. Demodulation processing techniques proved invaluable to the measurement of valve stroke time from inductive sensor traces alone and allowed detailed interpretation of ac SOV current traces for fault detection purposes. Similar monitoring techniques can be applied to dc-powered SOVs through the use of Hall-effect devices.

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Session 4A
Regulatory Results

Session Chair
Thomas G. Scarbrough
U.S. Nuclear Regulatory Commission

Generic Letter 89-10 and Resolution of the Motor-Operated Valve Issue[a]

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ABSTRACT

The U.S. Nuclear Regulatory Commission (USNRC) requires that motor-operated valves (MOVs) important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions they must perform. Despite these requirements, operating experience and research revealed problems with the performance of MOVs in operating nuclear power plants. In response to the concerns about MOV performance, the USNRC issued Generic Letter 89-10 (GL 89-10), "Safety-Related Motor-Operated Valve Testing and Surveillance," and its supplements. Many licensees are approaching completion of the aspects of their GL 89-10 programs associated with the review of MOV design bases, initial verification of MOV switch settings, testing of MOVs under design-basis conditions where practicable, and improvement of evaluations of MOV failures and necessary corrective action. Licensees will need to establish processes to ensure that the long-term aspects of their GL 89-10 programs, such as periodic verification of MOV capability and the trending of MOV problems, are maintained. Many MOV problems have been revealed at nuclear power plants as a result of the comprehensive programs of MOV testing and analyses developed by nuclear power plant licensees in response to GL 89-10. These MOV problems were corrected by the licensees when identified. The USNRC staff believes that the number of MOV problems and the operating events caused by those problems are being reduced by the response to GL 89-10 and will significantly decrease as licensees complete their GL 89-10 programs.

OVERVIEW

Many fluid systems at nuclear power plants depend on the successful operation of motor-operated valves (MOVs) in performing their safety functions. For example, MOVs may be required to open to allow cooling water to be supplied to the reactor core, steam generators, or containment building. They may be required to open to allow steam flow for turbine-driven pumps in safety systems supplying cooling water to the reactor core, steam generators, or containment building. MOVs may be required to close to prevent loss of coolant from the reactor core or to isolate the reactor containment. To ensure plant safety, they must be capable of performing their functions under design-basis conditions, which may include high fluid differential pressure and flow, high ambient temperature, and degraded motor voltage.

The complex nature of the MOV and the varied conditions under which it must operate demand

a. This paper was prepared by an employee of the U.S. Nuclear Regulatory Commission. It presents information that does not represent a current staff position. USNRC has neither approved nor disapproved its technical content.

that careful attention be paid to all applicable activities, from design to replacement, in order to ensure reliable operation. In the design of the MOV, a suitable analysis must be performed using valid engineering equations and parameters to ensure that the MOV will operate, as intended, under normal plant operations and during design-basis events. Manufacture, installation, preoperational testing, operation, inservice testing, maintenance, and replacement of the MOV must be conducted by trained personnel using proper procedures. Surveillance and testing criteria must be applied on a soundly based frequency in a manner that suitably detects questionable operability or degradation of the MOV. Moreover, these activities must be conducted in accordance with a strong quality assurance program.

REGULATORY REQUIREMENTS

The regulations of the U.S. Nuclear Regulatory Commission (USNRC) require that components important to the safe operation of a nuclear power plant be treated in a manner that provides assurance of their performance. Appendices A, "General Design Criteria for Nuclear Power Plants," and B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to of Title 10, Part 50 , of the *Code of Federal Regulations* (10 CFR 50) provide a broad-based framework of requirements for the design, testing, operation, and maintenance of components, including MOVs, that are important to the safe operation of the plant. With respect to inservice testing of MOVs, 10 CFR 50.55a(g) requires compliance with Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) for MOVs within the scope of that code. The recent revision of the USNRC regulations on maintenance activities in 10 CFR 50.65 also provides requirements that address the performance of certain MOVs in nuclear power plants.

MOV PROBLEMS

Despite the USNRC regulations, operating experience at nuclear power plants began to reveal weaknesses in many activities associated with MOV performance. For example, some engineering analyses used in the initial design sizing and setting of MOVs were inadequate in predicting the thrust and torque required to open and close valves under design-basis conditions. Both regulatory and industry research programs later confirmed the weakness in the initial design and qualification of MOVs. Shortcomings in maintenance programs, such as inadequate procedures and training, have also resulted in poor MOV performance. Typical inservice testing that consisted of the measurement of valve stroke times under zero differential pressure and flow conditions has been shown to be insufficient to detect certain deficiencies that could prevent MOVs from performing their safety functions under design-basis conditions.

In the 1980s, the extent of MOV problems began to become apparent. For example, a complete loss of main and auxiliary feedwater (AFW) occurred at the Davis-Besse Nuclear Power Station on June 9, 1985, during which time the MOVs in the AFW system could not be reopened electrically after they had been inadvertently closed. At Unit 2 of the Catawba Nuclear Station on March 14, 1988, an MOV in the AFW system failed to close completely against high differential pressure and flow, and subsequent testing revealed that other MOVs in the AFW systems of Catawba Units 1 and 2 were unable to close under those conditions. At the Palisades Nuclear Plant on November 21, 1989, an MOV used to isolate the power-operated relief valve failed to close under high differential pressure and flow conditions during a postmodification test. Many more MOV problems have occurred or have been identified over the last few years.

NRC ACTION PLAN ON MOV PERFORMANCE

The potential safety-significance of MOV failure, the complex phenomena and other factors

affecting MOV performance, the wide variety of MOV problems, and the slow progress in resolving those problems led to the recognition that a comprehensive program was needed to gain assurance that MOVs would perform well in nuclear power plants. As a result, the USNRC staff issued NUREG-1352 (June 1990), *Action Plans for Motor-Operated Valves and Check Valves*, which described actions to organize the activities aimed at resolving the concerns about MOV (and check valve) performance. Among those actions are evaluation of the current regulatory requirements and guidance applicable to MOVs, development of guidance for and coordination of USNRC inspections, completion of USNRC MOV research programs, implementation of the research results, and provision of MOV information to the nuclear industry.

GENERIC LETTER 89-10

A significant task of the MOV action plan is the USNRC staff's review of the implementation at nuclear power plants of Generic Letter (GL) 89-10 (June 28, 1989), "Safety-Related Motor-Operated Valve Testing and Surveillance," and its supplements. In GL 89-10, the USNRC staff asked nuclear power plant licensees to help ensure the capability of MOVs in safety-related systems by reviewing MOV design bases, verifying MOV switch settings initially and periodically, testing MOVs under design-basis conditions where practicable, improving evaluations of MOV failures and necessary corrective action, and looking for trends in MOV problems. The staff requested that licensees complete the GL 89-10 program within three refueling outages or 5 years from the issuance of the generic letter, whichever is later.

Supplement 1 to GL 89-10

The USNRC staff issued Supplement 1 to GL 89-10 on June 13, 1990, to give licensees detailed information on the results of public workshops held in 1989 to discuss the generic letter.

Supplement 2 to GL 89-10

On August 3, 1990, the staff issued Supplement 2 to GL 89-10 to allow licensees additional time to review and to incorporate the information contained in Supplement 1 into their programs in response to the generic letter.

Supplement 3 to GL 89-10

Tests performed by the Idaho National Engineering Laboratory (INEL) as part of a program by the USNRC Office of Nuclear Regulatory Research reinforced concerns regarding the capability of MOVs to perform their design-basis functions. At a public meeting on April 18, 1990, the INEL researchers discussed the results of the USNRC-sponsored MOV tests that revealed that more thrust was required to operate the tested valves under high differential pressure and flow conditions than had been predicted using standard industry calculations. These test results were directly applicable to the safety function of MOVs used for containment isolation in the high-pressure coolant injection (HPCI), reactor core isolation cooling (RCIC), and reactor water cleanup (RWCU) systems of boiling water reactor (BWR) plants. After a summary review of the capability of MOVs in those systems and discussions with the BWR Owners Group, the USNRC staff issued Supplement 3 to GL 89-10 on October 25, 1990, in which it asked licensees of BWR plants to perform a plant-specific safety analysis and to evaluate the capability of MOVs used for containment isolation in the HPCI, RCIC, and RWCU systems (and in isolation condenser lines), as applicable. Also, the USNRC staff asked all licensees to consider the results of the MOV tests in their GL 89-10 programs. BWR licensees have completed their evaluations of the MOVs within the scope of Supplement 3 to GL 89-10 and have modified or adjusted many MOVs to provide assurance of their capability to perform their design-basis functions.

Supplement 4 to GL 89-10

On February 12, 1992, the USNRC staff issued Supplement 4 to GL 89-10 and stated that

BWR licensees need not address inadvertent MOV operation as part of their GL 89-10 programs based on an USNRC-sponsored study of core-melt probability by the Brookhaven National Laboratory (BNL). Nevertheless, the USNRC staff stated its belief that consideration of inadvertent MOV operation benefitted safety.

Supplement 5 to GL 89-10

As an integral part of their GL 89-10 programs, most licensees are relying on MOV diagnostic equipment to obtain information on the thrust required to open or close the valve as well as the thrust delivered by the motor actuator. The various types of MOV diagnostic equipment estimate stem thrust using different parameters, such as spring pack displacement or strain in the stem, mounting bolts, or yoke. The use of MOV diagnostic equipment can have a significant effect on the safe operation of a nuclear power plant because some licensees make decisions regarding the operability of safety-related MOVs on the basis of thrust readings of diagnostic equipment.

During the implementation of GL 89-10, the USNRC staff became aware of information that raised a generic concern regarding the reliability of the data provided by MOV diagnostic equipment. For example, on February 3, 1992, the MOV Users Group (MUG) of nuclear power plant licensees released "Final Report—MUG Validation Testing as Performed at Idaho National Engineering Laboratories" (Volume 1), which indicated that MOV diagnostic equipment relying on spring pack displacement to estimate stem thrust was not as accurate as its vendors believed. In addition, on October 2, 1992, a manufacturer of MOV diagnostic equipment that derives thrust from yoke strain calibrated to stem thrust using measured diametral strain of the valve stem and nominal engineering material properties notified the USNRC that two new factors that could affect the thrust values obtained with its equipment involved (a) the possible use of improper stem material constants and (b) the failure to account for a torque effect when the equipment is calibrated to strain in the threaded portion of a valve stem.

The manufacturers of MOV diagnostic equipment have evaluated the information revealing the increased inaccuracy of their equipment and have provided guidance to the licensees for their use in correcting the data obtained from their equipment. Further, the manufacturers are developing improved equipment and software to provide more accurate thrust and torque measurements.

On June 28, 1993, the USNRC issued Supplement 5 to GL 89-10, in which it asked licensees to reexamine their MOV programs and to identify measures taken or planned to account for uncertainties in MOV diagnostic equipment. Nuclear power plant licensees were required to notify the USNRC staff of their diagnostic equipment and to report their plans to address the information on the accuracy of MOV diagnostic equipment. The USNRC staff has reviewed the licensee responses to Supplement 5 to GL 89-10 and sent replies to the individual licensees. USNRC inspections will address specific aspects of licensees' actions to address MOV diagnostic equipment inaccuracy.

Supplement 6 to GL 89-10

On March 8, 1994, the USNRC issued Supplement 6 to GL 89-10 to transmit information to licensees on the schedule of GL 89-10 programs and the grouping of MOVs to share test data, and to respond to questions raised at the public workshop held in February 1993 to discuss the generic letter. In Supplement 6 to GL 89-10, the USNRC staff also requests that, if a licensee intends to extend its schedule for completing the GL 89-10 program, the licensee submit specific information on the capability of those MOVs whose test schedule will be extended. In Supplement 6, the USNRC staff states that licensees are expected to have their safety-related MOVs set up using the best-available MOV test data by the original completion date accepted by the USNRC, even if their GL 89-10 test schedules are extended.

Proposed Supplement 7 to GL 89-10

The USNRC staff contracted with BNL to perform a core-melt probability study to address valve mispositioning in pressurized water reactor (PWR) nuclear power plants. This study was similar to that performed by BNL to address valve mispositioning in BWR plants. The USNRC staff is preparing proposed Supplement 7 to GL 89-10 to discuss its position on the need for considering inadvertent MOV operation in PWR nuclear power plants.

Proposed Generic Letter on Pressure Locking and Thermal Binding of Gate Valves

In March 1993, the USNRC issued NUREG-1275, Volume 9, *Pressure Locking and Thermal Binding of Gate Valves*, which gives the history of pressure-locking and thermal-binding events, describes the phenomena, discusses the effects of locking or binding on valve functionality, summarizes preventive measures, and assesses the safety significance of the phenomena. Several generic industry and regulatory communications provide guidance for identifying susceptible valves and performing appropriate preventive and corrective measures. For example, the USNRC staff included the consideration of pressure locking and thermal binding of gate valves in its review of licensee programs in response to GL 89-10. However, many licensees have taken only minimal action to address this issue because of the uncertainties surrounding when pressure locking and thermal binding might occur and the thrust required to overcome these phenomena. Consequently, pressure-locking and thermal-binding events have occurred during normal plant operations, and therefore might occur when an MOV is needed to perform its safety function at a nuclear power plant. As a result, the USNRC staff is preparing a proposed generic letter to request that licensees identify power-operated gate valves susceptible to pressure locking and thermal binding and implement corrective action for those valves within a specific schedule.

USNRC Inspections of GL 89-10 Programs

The USNRC staff issued Temporary Instruction (TI) 2515/109 (January 14, 1991), "Inspection Requirements for Generic Letter 89-10, Safety-Related Motor-Operated Valve Testing and Surveillance," to provide guidance for its inspectors when evaluating programs developed at nuclear power plants in response to GL 89-10. Part 1 of the TI contains guidance for performing inspections to review programs developed in response to GL 89-10. Part 2 of the TI contains guidance for performing inspections to determine the adequacy of the implementation of GL 89-10 programs. The inspections under Part 2 of the TI focus on a sample of specific MOVs to determine the adequate implementation of the overall GL 89-10 program at a nuclear power plant. On June 14, 1993, the USNRC staff issued Revision 1 to the TI to update its guidance on the basis of inspections of GL 89-10 programs conducted to date.

In January 1991, the USNRC staff began inspecting the programs developed by licensees in response to GL 89-10. The staff has completed its inspections to review the development of MOV programs in response to GL 89-10 and is currently performing inspections to evaluate the implementation of GL 89-10 programs. Another speaker during the symposium will discuss the results of the staff's MOV inspections.

LONG-TERM ASPECTS OF GL 89-10

Many licensees are approaching completion of the aspects of their GL 89-10 programs associated with review of MOV design bases, initial verification of MOV switch settings, testing of MOVs under design-basis conditions where practicable, and improvement of Evaluations of MOV failures and necessary corrective action. In Paragraph d in GL 89-10, the staff recommended that licensees prepare procedures to ensure that

correct MOV switch settings are maintained throughout the life of the plant. In Paragraph h in GL 89-10, the staff suggested that MOV data be periodically examined to establish trends of MOV performance. In Paragraph j in GL 89-10, the staff stated that the surveillance for periodic verification of MOV capability should not exceed 5 years or three refueling outages, unless a longer interval is justified. Licensees will need to establish processes to ensure that these long-term aspects of their GL 89-10 programs are maintained.

Identification and Correction of MOV Problems

A significant number of MOV problems have been revealed at nuclear power plants as a result of the comprehensive programs of MOV testing and analyses developed by licensees in response to GL 89-10. These MOV problems were corrected by the licensees when identified. The USNRC staff believes that the number of MOV problems, and operating events caused by those problems, are being reduced by the response to GL 89-10, and will significantly decrease as licensees complete their GL 89-10 programs.

MOV Research

In addition to performing MOV inspections, the USNRC staff has identified areas requiring further research and analysis to assist the staff in evaluating GL 89-10 programs at nuclear power plants. For example, NUREG/CR-5720, *Motor-Operated Valve Research Update*, contains important information on several areas of MOV behavior under high-load conditions. Additional ongoing research is improving the understanding of MOV performance in support of regulatory activities.

MOV Meetings

The USNRC staff provides information to the nuclear industry through meetings to assist licensees in resolving the MOV issue at their particular facilities. For example, the staff discusses the MOV issue at regulatory information conferences and presents the status of USNRC activities and current concerns at meetings of the MOV Users Group of nuclear power plant licensees.

NRC Information Notices

The USNRC staff issues information notices to alert licensees to important aspects of MOV performance. For example, the USNRC issued Information Notice (IN) 92-23, "Results of Validation Testing of Motor-Operated Valve Diagnostic Equipment"; IN 93-74, "High Temperatures Reduce Limitorque AC Motor Operator Torque"; IN 93-88, "Status of Motor-Operated Valve Performance Prediction Program by the Electric Power Research Institute"; IN 93-97, "Failures of Yokes Installed on Walworth Gate and Globe Valves"; IN 93-98, "Motor Brakes on Valve Actuator Motors," and IN 94-10, "Failure of Motor-Operated Valve Electric Power Train Due to Sheared or Dislodged Motor Pinion Gear Key."

EPRI MOV Performance Prediction Program

The USNRC staff meets regularly with representatives of the Nuclear Energy Institute (NEI, and formerly the Nuclear Management and Resources Council or NUMARC) and the Electric Power Research Institute (EPRI) to discuss the EPRI MOV Performance Prediction Program. EPRI tested gate, globe, and butterfly valves and analyzed the results of additional valve tests, as part of its development of a methodology to predict the performance of MOVs. NEI has submitted the EPRI MOV Performance Prediction Program as a topical report for USNRC staff review.

Code and Standard Committees

The USNRC staff participates on the committees responsible for improving codes and standards for MOV performance. For example, the USNRC staff participated in the preparation of ASME OM-8, "Startup and Periodic Performance Testing of Electric Motor Operators on Valve Assemblies in Nuclear Power Plants." The

USNRC staff is also participating in the revision of ASME Standard QME, "Qualification of Mechanical Equipment Used in Nuclear Power Plants," to improve the functional qualification requirements for valve assemblies.

CONCLUSION

The USNRC staff recognizes the significant amount of licensee resources that has been required to implement MOV programs in response to GL 89-10. However, the MOV programs established in response to GL 89-10 have led to the identification and resolution of numerous weaknesses in the design, qualification, and maintenance of MOVs, and the corrective action for and the trending of MOV problems. Through its inspection program, the USNRC staff has found that significant progress has been made by the nuclear industry in the design, qualification, and maintenance of MOVs. Therefore, the USNRC staff believes that MOV problems will decrease and that MOV performance will continue to improve in the future.

As the nuclear industry and the USNRC staff work toward resolving the MOV issue, the staff plans to (a) continue to inspect MOV programs at nuclear power plants, (b) complete the preparation of proposed Supplement 7 to GL 89-10 on the need to consider inadvertent operation of MOVs in PWR nuclear power plants under the GL 89-10 program, (c) prepare a proposed generic letter on pressure locking and thermal binding of gate valves, (d) complete the review of the EPRI MOV Performance Prediction Program Topical Report, and (e) continue to meet with, and provide information to, licensees regarding MOV performance.

Motor-Operated Valve Inspection Results[a]

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ABSTRACT

The U.S. Nuclear Regulatory Commission staff conducted inspections of motor-operated valve (MOV) programs in nuclear power plants according to guidance in Temporary Instruction 2515/109, "Inspection Requirements for Generic Letter 89-10, Safety-Related Motor-Operated Valve Testing and Surveillance." This paper discusses specific findings from the plant inspections in the following areas: scope, design-basis review, MOV sizing and switch settings, MOV design-basis verification, periodic verification of design-basis capability, corrective action and trending, and schedule.

INTRODUCTION

The U.S. Nuclear Regulatory Commission (USNRC) staff has been conducting inspections of motor-operated valve (MOV) programs at nuclear power plants according to the guidance in Temporary Instruction (TI) 2515/109, "Inspection Requirements for Generic Letter 89-10 (GL 89-10), Safety-Related Motor-Operated Valve Testing and Surveillance." The TI divided the USNRC inspection activity into two parts—program review (Part 1) and implementation (Part 2). The USNRC staff revised TI 2515/109 on June 14, 1993, to reflect inspection experience. The staff has performed Part 1 program reviews at each nuclear power plant. On February 26, 1992, the staff issued Information Notice 92-17, "USNRC Inspections of Programs being developed at Nuclear Power Plants in response to Generic Letter 89-10," which summarized the findings of the GL 89-10 inspections conducted up to that time. Since February 1993, the staff has performed over 30 Part 2 implementation inspections. The objective of this paper is to discuss the findings of the Part 2 inspections.

In contrast to the general programmatic overview performed during the Part 1 inspections, the Part 2 inspections focus on a specific selection of MOVs, usually four to ten in number. This is sometimes referred to as a "vertical slice" review of the implementation of the licensee's MOV program. The detailed inspection of the selected MOVs includes evaluation of design-basis documents, sizing and switch setting calculations, testing procedures, and diagnostic traces with valve-specific and programmatic issues identified.

SCOPE

The USNRC inspections show, for the most part, that licensees are establishing the scope of their GL 89-10 programs consistent with the recommendations of the generic letter. Most of the questions regarding the identification of valves to be included in the scope of the GL 89-10 program were resolved during the Part 1 inspections.

DESIGN-BASIS REVIEW

With respect to the recommendations of GL 89-10 regarding design-basis reviews of

a. This paper was prepared by an employee of the U.S. Nuclear Regulatory Commission. It presents information that does not represent a current staff position. The USNRC has neither approved nor disapproved its technical content.

MOVs, licensees have been reviewing plant documentation (such as the final safety analysis report and technical specifications) to determine the design-basis conditions for safety-related MOVs. Some licensees had focused on differential pressure and had not adequately addressed other design-basis parameters (such as flow, fluid temperature, ambient temperature, and seismic/dynamic effects). Although differential pressure is the primary design-basis parameter used to predict thrust requirements in the present industry equations, other design-basis parameters also need to be considered to ensure that the test results demonstrate that the MOV will operate under design-basis conditions. Many licensees found that they needed to update their degraded voltage studies to ensure that the design-basis voltage is determined at each MOV.

A significant concern from the inspections has been the weaknesses in the evaluation of the potential for pressure locking and thermal binding of gate valves. In several cases, the effort to evaluate MOV susceptibility to pressure locking and thermal binding was not comprehensive. Generally, these shortcomings involved the failure to consider all of the operating modes within the design basis of the plant that a particular MOV may encounter, including rapid depressurization events, check valve leakage, and abnormal pump and valve configurations during maintenance.

Several inconsistencies and discrepancies discovered in the MOV programs were the result of licensees failing to completely assess the impact caused by a change in a design-related document. For example, a revision to a seismic calculation may affect the weak-link structural calculation. Changes to the ambient temperature of a room can affect motor capability calculations. The removal of a strainer or check valve, or the replacement of a pump, can change an MOV's maximum expected differential pressure. A change to the calculated degraded voltage of an MOV can affect the operability of motor control center equipment. Because of the complexities involved in MOV performance, licensees are encouraged to establish information management systems that facilitate and ensure proper data exchange among all repositories of design information that influence calculations of MOV capability.

MOV SIZING AND SWITCH SETTINGS

Licensees use various methods to determine the proper size of MOVs and their appropriate switch settings. Some licensees have increased the valve factors assumed in the industry equation (used to predict the thrust required to operate the valves) to reflect industry and plant-specific experience. However, a few licensees continued to use previous guidance provided by valve vendors in estimating thrust requirements that have been, or may be, determined inadequate during design-basis MOV tests. The USNRC inspectors found that the validation of assumptions for the following parameters in the MOV calculations for sizing and switch settings needs improvement: valve friction coefficient (or valve factor), stem friction coefficient, and load-sensitive behavior where the output of the actuator may be less under dynamic conditions than under zero differential pressure and flow (static) conditions.

The following USNRC inspection findings reveal specific concerns for MOV calculations.

Thrust and Torque Limits

In several instances, licensees had increased permissible actuator thrust and torque limits beyond the structural ratings without a rigorous engineering justification. On the basis of a licensee contractor study, Limitorque has allowed certain actuators to undergo thrust levels up to 162% of nominal thrust ratings, provided specific conditions are met. Limitorque also considers it acceptable for actuators to undergo torque levels up to 110% of nominal ratings for 2,000 cycles and 120% for no more than 100 cycles. The USNRC staff has taken the position that any thrust or torque applied in excess of these levels must be appropriately justified.

Thermal Growth Effects

Valve stems of MOVs experience an elongation when the temperature increases from cold to hot operating conditions. The stem elongation may exceed that of the yoke and thus change the positional relationship between the limit switch gears and the disc/seat. If (a) the MOV torque switch bypass setting was adjusted under low temperature conditions during a refueling shutdown and (b) the bypass was set very near the point of seat contact, it is possible during hot operations that seat contact will occur before the bypass reinstates the torque switch. This can result in motor stall and potential overthrusting of the MOV. Similarly, problems could occur where MOV closure is controlled fully by the limit switch.

Although inspection results have shown that the thermal growth phenomenon is rare from a macroscopic point of view (i.e., valve failure, nonactivation of torque switch in closing direction, inability to open following hot closure), it is possible that many MOVs are being routinely overthrusted during plant operation to thrust levels that are not measured by diagnostic equipment. It is also possible that some events attributed to pressure locking and thermal binding may result, at least in part, from the thermal growth phenomenon.

Torque Switch Repeatability

Margins accounting for torque switch repeatability were commonly included in calculations of minimum required thrust, but often not included in calculations determining maximum allowable thrust or torque. This exclusion is not justified because the repeatability of the torque switch is equally applicable to both directions. That is, it is not a biased effect.

For example, Limitorque Maintenance Update 92-02 provided increased repeatability values for torque switch settings of 1.0. Several licensees had not incorporated the revised values into their programs. Some licensees indicated the intention to use onsite test results to justify using lower repeatability values than those published by Limitorque.

Motor Actuator Assumptions

USNRC inspections found some licensees assuming motor actuator output greater than Limitorque predictions without adequate justification. From an inspection at Limitorque, the staff found that the individual parameters had little engineering basis. Licensees will need to justify assumptions of motor actuator output greater than that predicted by Limitorque.

In a few instances, motor stall torque (or a motor rating factor greater than 1.0) was used in the calculation of degraded voltage capability. Limitorque has endorsed the use of only the rated motor starting torque in these calculations. Another questionable practice was the use of published generic motor curves in determining available motor performance under degraded voltage conditions. Limitorque considers these motor curves to be representative of a limited sample of production tests of motors. Individual motor performance was expected to differ from the published curves. Limitorque has endorsed the use of the generic motor curves for estimating available motor current under degraded voltage conditions.

Application of Uncertainties

During the inspections, several variations were noted in the treatment of measurement uncertainties. In some cases, uncertainties were not applied in preliminary calculations for MOVs that had not been tested. In such a case, an MOV having an adjusted (for measurement uncertainties) maximum allowable thrust that was less in magnitude than its adjusted required minimum thrust could be considered capable of performing its safety function if the unadjusted numbers showed a positive margin. If an MOV does not have a setup margin consistent with the diagnostic system that will be used to test it, the capability of the MOV to perform its safety function should be considered questionable.

In other cases, uncertainties associated with the use of generic springpack or motor curves were

not factored into the calculations. Licensees need to consider uncertainties associated with information used to determine MOV capability.

Several questions arose concerning the method by which the uncertainty of diagnostic systems and torque switch repeatability should be applied. The errors may be applied to the calculated minimum and maximum thrusts to create a test window, or they may be applied directly to the measured value and then compared with the raw calculated numbers. The latter method appears to be more consistent with the physical basis of the error analyses or the test programs that were used to determine these values.

Quality Assurance

Though most licensees consider MOV testing and surveillance to be an activity subject to Appendix B to Part 50 of Title 10 of the *Code of Federal Regulations* (10 CFR 50), participation of the site quality groups in the MOV program at many sites was minimal. One apparent reason is that few quality assurance or quality control personnel have sufficient expertise to evaluate the technical complexities inherent in MOVs. Nevertheless, a marginally informed observer can provide an effective counterbalance to the tendency to commit errors of habit. The USNRC staff encourages a greater presence of quality groups in MOV programs and an effort to provide additional MOV training to quality inspectors.

Another concern related to quality assurance involved design calculations that had not been independently verified. At some sites, there may have been a tendency to perceive MOV calculations as an entity separate from the design engineering function and thus not necessarily subject to the same requirements. The USNRC staff's position has always been that calculations involving safety-related MOVs fall under the requirements of 10 CFR 50, Appendix B, Criterion III.

MOV DESIGN-BASIS VERIFICATION

With respect to the recommendations of GL 89-10 regarding MOV testing, licensees have found during differential-pressure and flow testing of MOVs that many gate valves (and some globe and butterfly valves) require more torque or thrust to operate than was predicted by the valve vendors.

Among the most significant inspection concerns regarding MOV testing have been (a) the lack of progress in completing dynamic testing, (b) weaknesses in procedures and acceptance criteria for the tests to evaluate the capability of the MOV to perform its safety function under design-basis conditions, and (c) lack of feedback of the test results into the methodology used by the licensee in predicting the thrust and torque requirements for other MOVs. Among other licensee activities that need improvement with respect to testing are (a) justification for the grouping of valves to share test information in order to minimize the number of MOVs tested, (b) verification of methods to extrapolate data from test conditions to design-basis conditions, (c) evaluation of anomalies in MOV diagnostic equipment signature traces, and (d) involvement of quality assurance personnel in verifying the accuracy of test data and analyses.

The USNRC regulations and plant-specific technical specifications establish requirements for actions and reporting by licensees when safety-related equipment is determined to be, or has been, unable to perform its safety functions. When a problem is found with one of its safety-related MOVs, the licensee must evaluate the impact of that problem on the capability of the MOV to perform its safety function. Generic Letter 91-18, "Information to Licensees Regarding Two USNRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and Operability," contains information on guidance provided to USNRC inspectors in the area of operability of safety-related components. This information is also useful to licensees in

evaluating the operability of an MOV found to have a performance problem.

The following sections provide some specific USNRC inspection findings concerning MOV testing.

Test Conditions

Several examples were identified where a differential pressure test of an MOV did not show indications of dynamic flow effects on the diagnostic traces. This situation was generally caused by a test configuration that diverted flow from the tested MOV or involved a pumping arrangement that was different from the design-basis calculation. Another situation that may incorrectly give the appearance of a high differential pressure test is the lack of continuously recorded upstream and downstream pressures. For example, if differential pressure is computed solely by taking the difference between the upstream and downstream pressure following a closing stroke, the result may indicate a large differential pressure even if the amount of flow passing through the valve during the test was small. The extreme example would be a test that closes a valve against a hydrostatic head in which case-significant pressure differences across the valve do not occur until after flow is isolated. The best method to ensure a realistic simulation of the design condition is to conduct the test using the same pump and valve configuration as that assumed in the design-basis calculation. When this configuration is used, observed pressures may be used to revise the design-basis differential pressure on an empirical basis. This may provide an immediate benefit in establishing additional margin for the tested valve and other valves that operate in a similar configuration.

Marking or Interpretation of Diagnostic Traces

In a small number of cases, MOV diagnostic test signature traces were incorrectly marked or interpreted. These errors mostly involved incorrectly identifying the points of flow cutoff and seat contact during a closing diagnostic stroke, marking points on cyclic traces at the peak or trough of the sine wave (rather than at midcycle), and identifying running load where dynamic effects were present. Some licensees conducted additional training in response to the USNRC inspection findings. This issue is considered significant because the margins that are applied to measured thrust values to account for diagnostic system uncertainty do not include an allowance for errors in trace interpretation. For example, during the USNRC inspections, cases were identified where the licensee underestimated the dynamic-effect thrust of an MOV by 50% because the point of flow isolation was improperly marked.

Acceptance Criteria

Deficiencies in MOV diagnostic test acceptance criteria were observed at some sites. A typical problem was the failure to evaluate the traces for indications of abnormal MOV operation and to document this evaluation. In one case, a valve had exhibited a high running load indicative of a bent stem. The licensee had decided that the anomaly was not consequential to the proper operation of the valve. Subsequently, the valve failed to open during testing and was later discovered to have a damaged and overheated worm and worm gear. This example illustrates the danger of overemphasizing the quantitative information at the expense of the qualitative information afforded by the diagnostic trace.

Another weakness observed in the acceptance criteria was a lack of clarity and conciseness. Though these qualities may be perceived as matters of style, mistakes in the analytical evaluations are often caused by the interface with a complex, confusing process.

Validation of Assumptions

A general trend existed where assumptions made for valve factor, stem friction coefficient, and load sensitive behavior appeared to be low and not sufficiently supported by test data for similar valves. In these cases, the necessary

correlation between the engineering calculations and the empirical data from the field was not completed. Licensees will need to justify assumptions before completing their GL 89-10 programs.

One persistent observation concerning MOV design assumptions was that the original assumptions, made in advance of the anticipated receipt of onsite test results, were often low. For example, a valve factor of 0.3, or stem friction coefficient of 0.15, or load-sensitive behavior of 0 to 10% might be assumed before test results were available to confirm these values. As a result, many licensees had to revise design calculations when the onsite test results failed to confirm the original assumptions.

PERIODIC VERIFICATION OF DESIGN-BASIS CAPABILITY

With respect to the recommendations of GL 89-10 regarding periodic verification of MOV capability, many licensees have stated that they will attempt to use tests of MOVs with diagnostic equipment under static conditions to demonstrate the adequacy of torque switch settings and the continued capability of MOVs to perform their safety functions under design-basis conditions. No licensee, as yet, has provided justification for applying the results of tests conducted under static conditions to demonstrate design-basis capability. With respect to postmaintenance testing, many licensees are improving their methods to demonstrate continued capability of MOVs to perform their safety functions under design-basis conditions after maintenance.

CORRECTIVE ACTION AND TRENDING

With respect to the recommendations of GL 89-10 regarding MOV failures, corrective action, and trending, the USNRC inspectors found weaknesses in some licensees' responses to MOV failures and deficiencies. Two specific USNRC inspection findings on corrective action and trending are as follows:

- Corrective Action

  Many of the significant findings during USNRC MOV inspections have been in the area of corrective action. Typically, inadequate corrective action involved failing to evaluate the generic implications of a discovered problem. Often, the licensee neglected to consider the effect an MOV problem had on other similar valves. With the increased use of valve grouping, the need to apply test results to other applicable MOVs has become even more important. When one valve of a group fails, the capability of other untested valves in the group should be considered in question until the cause of the failure is determined to be not applicable to the rest of the group. As an example, during one of the Part 2 inspections, the USNRC learned that the licensee had recently determined that a valve factor of 0.75 would be required for Powell gate valves. The licensee had inserted the higher assumed valve factor into the thrust calculations, but did not assess the impact this action had on the assumed capability of the Powell valves that had not undergone differential pressure testing.

  Another type of corrective action problem found during the Part 2 inspections was failure to identify a degraded MOV. This is often tied to a deficiency in the acceptance criteria, a misinterpreted diagnostic trace, a mistake in transferring data, or a computational error. The probability of these types of oversights can be minimized with a review process that includes a check by a second engineer.

- Trending

  For the most part, trending programs have been developed to manage and analyze information related to MOV test results, maintenance problems, and failures. However, little progress had been made to implement these programs. The USNRC staff considers implementation of an MOV

trending program to be necessary for closure of GL 89-10 at a given site.

SCHEDULE

During the GL 89-10 inspections, the USNRC staff found that some licensees have not made adequate progress in resolving the MOV issue for their facilities within the recommended schedule of GL 89-10. Some licensees have received extensions to their schedule commitments to GL 89-10. Current requests are being evaluated in accordance with the guidance in Supplement 6 to GL 89-10, which was issued on March 8, 1994.

In summary, the GL 89-10 Part 2 inspections have revealed a pronounced improvement in licensees' MOV programs since the Part 1 inspections. Licensees have conducted a large number of differential pressure tests to verify the design-basis capability of MOVs. The inspectors found improvements in diagnostic testing equipment, MOV test acceptance criteria, feedback of test results, database control, MOV training and expertise, and justification for both policies and engineering assumptions. However, particular licensees need to pay additional attention in some of these areas. The USNRC staff believes that the undertaking by the licensees to verify the capability of MOVs to perform their intended safety functions and have resulted in a significant overall improvement in nuclear safety.

may provide additional justification for an alternative; at worst, not mentioning the test in the one direction may cause confusion. Some relief requests describe the justification in two sentences or less, leaving it to the reviewer to fill in the details to justify the alternative. Inadequate justifications, and description of alternatives can be directly correlated to increases in the review time and contribute to the possibility that the request will be denied or granted on an interim basis until additional justification is submitted.

Although most program submittals give the Code edition applicable to the program and the interval and interval dates, some still do not include such information. This information is necessary to ensure that any relief request is reviewed using the correct edition of the Code, and the decision to grant relief or not may depend, in part, on the interval dates. If a request is not acceptable for long-term relief, it may be acceptable until the end of the interval. Relief requests expire at the end of each 120-month interval when the IST program is updated to a new Code edition, unless the safety evaluation states that the interim relief can apply into the next interval to allow time for resolving the outstanding issues. When updating to OM-6 and OM-10 requirements, or later to the OM Code, many relief requests will no longer be required. Also, if a licensee uses the positions in final NUREG-1482, many relief requests will no longer be required.

FUTURE OUTLOOK

It appears that the IST program is evolving from a fairly straightforward program that did not allow for much creativity to one that will become uniquely suited to each plant. The presentations on the effectiveness of IST indicate that many failures occur that are not identified by IST (though many are). Presentations on applying risk analysis to testing programs indicate that testing frequencies can be evaluated and optimized. In the current marketplace and economic climate, licensees want more for their expenditure of time and resources in developing and implementing their IST programs. They want a program that is cost-effective, meaningful, appropriate for the components tested, tailored for the plant-specific conditions, and effective in accomplishing its intended purpose. As the future unfolds, plants that have test data in computer databases will benefit. Equipment trends will become more and more important as test frequencies are extended, as test methods change, and as risk analysis applications become part of the licensees' justifications for relief.

It is important for the O&M committees to be sensitive to the different forces acting on the end users. Changes and revisions to the Codes and Standards should be justified, and a basis for each change should be documented. At the same time, it is important that the end users provide input to the O&M committees and comment on actions that they view as unnecessary or inappropriate. The USNRC staff is often put in a position, when evaluating a relief request, that requires the regulator to decide on an alternative to the Code requirements with no knowledge of whether or not the committees would find the alternative acceptable. Although it is inappropriate for the USNRC to undermine the Code in approving alternatives, it is becoming increasingly difficult to maintain that perspective, particularly when the basis for a requirement cannot be ascertained.

Inservice Testing Regulatory Overview[a]

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INTRODUCTION

In 1989, the U.S. Nuclear Regulatory Commission (USNRC) issued Generic Letter 89-04 (GL 89-04), "Guidance on Developing Acceptable Inservice Testing Programs," to address the backlog of staff reviews of relief requests from the inservice testing (IST) requirements. The USNRC asked certain licensees to respond to the generic letter by indicating which relief requests did not comply with the guidance in the positions in Attachment 1 of the generic letter. The USNRC has reviewed the responses and has issued safety evaluations for those that included new or revised relief requests. The USNRC is now able to review licensee submittals within 6 to 9 months. On December 16, 1993, a draft supplement to GL 89-04 was published for comment in the *Federal Register* (Volume 58, No. 240, pages 65738 and 65739) referencing draft NUREG-1482, *Guidelines for Inservice Testing at Nuclear Power Plants.* A public meeting was held on February 2 and 3, 1994. The staff received a number of questions related to the content of the NUREG report and requests that the USNRC address additional issues. The comments are being incorporated into the NUREG report as appropriate. All questions are being included in an appendix to the report along with staff responses and suggestions on how to obtain the requested information. Questions that may be more appropriately addressed by the American Society of Mechanical Engineers (ASME) Operations and Maintenance (O&M) Code committees are being consolidated into a letter from the USNRC to the ASME.

Three areas that were discussed at length during the public meeting were (a) safety and relief valve testing using Part 1 of the O&M Code (OM-1-1981 and OM-1-1987), (b) check valves and alternative methods or frequencies of testing, and (c) scope of the IST program. To the extent practical, the concerns expressed at the public meeting in these three areas are being addressed in the final guidelines document. The number of questions indicates that further guidance is needed, either from the USNRC or from the ASME O&M Code committees. Many of the questions related to Part 1 have been resolved with the most recent revision, which corrects some editorial errors and clarifies issues raised by users who provided input to the O&M working group.

INSPECTIONS

Since the 1992 symposium, the USNRC staff has conducted, several inspections that included IST. Although some of the inspections identified IST programs that were well developed and adequately implemented, most of them identified a violation or a weakness. Examples of the violations or weaknesses are as follows:

- Instruments for measuring pump discharge pressure did not meet the requirements for a maximum full-scale range of three times the reference value or less.
- The essential service water pump test procedure did not establish a 5-minute run time after stable operation before data measurements are taken.

a. This paper was prepared by an employee of the U.S. Nuclear Regulatory Commission. It presents information that does not represent a current staff position. The USNRC has neither approved nor disapproved its technical content.

- Pump test procedures included incorrect acceptance criteria for inservice testing.
- Backflow testing of pump discharge check valves was not adequate to ensure closure.
- Five inservice tests were performed using an out-of-date procedure.
- Manual bypass valves that must repositioned to achieve a safety-related function were not included in the IST program.
- Safety-related, Code Class 2 check valves were installed in the main steam supply bypass line to the auxiliary feedwater pump turbine as part of a modification package. The check valves were not added to the IST program until a year after the modification was completed.
- Valves that were in the IST program had not been tested as required.
- Check valve flow tests did not specify the correct design accident flow.
- Several valves with safety-related function were not included in the IST program or were not tested in each safety direction: (a) residual heat removal cross-connect valves, with an open and close safety function, were not in the IST program; (b) discharge check valves from the refueling water storage tank to the residual heat removal pumps were not verified to be capable of closing; (c) isolation valves from the refueling water storage tank to the charging pump suction were not verified to be capable of closing; and (d) volume-control tank outlet check valves were not verified to be capable of closing.
- One licensee interpreted the Code to require stroke-time measurements in only one direction, even if the valve had a safety-related function in both directions.
- The IST procedure for testing the auxiliary feedwater pump did not contain a 5-minute run period after stable operation before data measurements are taken.
- Class 3 valves in the control room heating, ventilation, and air conditioning system were included in the IST program, but had not been tested.
- Alert and Required Action levels for the high-pressure safety injection pump were established at levels two times higher than specified by the Code.
- A valve stroke time alert limit was exceeded without the proper corrective action to increase the test frequency to monthly.
- Safety-related, Code Class 3, boric acid makeup pump discharge check valves were not included in the IST program.
- The tracking system for valves tested at a cold shutdown frequency was inadequate.

Several inspection reports identified the involvement of engineering, or the assignment of a permanent group including engineers, as a major strength and improvement in the IST area. The following examples are cases where engineering involvement proved to be valuable: (a) an inadequate reference value was corrected, (b) inaccurate acceptance criteria were corrected, and (c) program development was improved based on engineering review of the plant safety analysis.

IST SUBMITTALS

The quality of IST submittals, particularly relief requests, has improved over the last 2 years, although in general, more information could be included to further improve the quality. For example, some relief requests do not identify the Code requirement(s) from which relief is requested. In some instances, relief from testing in one direction is requested for a valve that has safety functions in both directions; the relief request, however, does not mention the other function because it is not intended to be part of the request. In such cases, testing in one direction

USNRC and Industry's Activities to Improve the Performance of Check Valves[a]

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ABSTRACT

In response to staff concerns over reported performance and operational readiness of check valves, the U.S. Nuclear Regulatory Commission (USNRC) developed a plan to promote improvements in the performance and operational readiness of check valves. The action plan to organize activities aimed at resolving the concerns about check valve performance and operational readiness is described in the USNRC report, NUREG-1352, "Action Plan for Motor-Operated Valves and Check Valves," issued in June 1990. The implementation and interim progress of the efforts were presented at the July 1992, USNRC/ASME Second Symposium on Pump and Valve Testing. This paper reports on the status of subsequent efforts of the action plan activities, industry activities, staff conclusions, and future plans.

INTRODUCTION

The regulations of the U.S. Nuclear Regulatory Commission (USNRC) require that components that are important to the safe operation of a nuclear power plant be treated in a manner that provides assurance of their performance. Appendices A, "General Design Criteria for Nuclear Power Plants," and B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to Part 50 of Title 10 of the *Code of Federal Regulations* (10 CFR 50) provide a broad-based framework of requirements for the design, testing, operation, and maintenance of components, including check valves that are important to the safe operation of the plant. With respect to inservice testing of check valves, 10 CFR 50.55(g) requires compliance with Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) for check valves within the scope of that code.

The significance of the need to maintain check valves in an operating condition commensurate with the importance of the safety function performed was demonstrated by an event at San Onofre Nuclear Generating Station's Unit 1 in 1985. A partial loss of power following a Unit 1 reactor trip resulted in a severe water hammer incident in the feedwater system. The failure of five safety-related check valves in the feedwater system had significant involvement in the event, which caused a leak, damaged plant equipment, and challenged the integrity of safety systems. The event and associated follow-on activities are documented in the USNRC's NUREG-1190, *Loss of Power and Water Hammer Event at San Onofre 1 on November 21, 1985* (USNRC, 1986). After the event, industry responded to the recognized need to improve check valve performance and solve operational problems by initiating several activities, including a workshop on check valve problems, guidance on check valve programs, guidelines for check valve applications review, and plant audits. In April 1989, the Nuclear Industry Check Valve

a. This paper was prepared by an employee of the U.S. Nuclear Regulatory Commission. It presents information that does not represent a current staff position. USNRC has neither approved nor disapproved its technical content.

Group (NIC) was formed, and in September 1990 the ASME/Operations and Maintenance Committee's Working Group on Check Valves (WGCV, OM-22) conducted its first meeting.

Staff concerns about continuing failures and the slow progress in addressing improvements in check valve performance and operational readiness dictated the need for a more active USNRC staff role. The USNRC developed a plan to foster and monitor activities to improve check valve performance and operational readiness and published *Action Plan for Motor-Operated Valves and Check Valves*, in June 1990 (Scarbrough 1990). The major plan activities consisted of efforts to identify problems and performance weaknesses, assess adequacy of regulatory requirements, support the development of codes and standards, develop licensee inspection guidance, conduct research studies, evaluate industry improvement efforts, evaluate the effectiveness of licensee activities regarding testing and performance of safety-related check valves, and determine the need for new regulatory guidance.

The USNRC staff developed Temporary Instruction (TI) 2525/110 (USNRC 1991), which is inspection guidance for evaluating the effectiveness of licensee activities with regard to monitoring check valves and maintaining proper performance and operating condition. Following a series of trial audits conducted by the staff, the TI was issued to USNRC regional inspectors in November 1991 for implementation. The development, implementation, and results of the audits and inspections using the TI were presented during the July 1992 Second NRC/ASME Symposium on Pump and Valve Testing (USNRC, 1992).

This paper will update the progress of action plan efforts and industry activities regarding improvements in check valve performance and maintenance of operating condition.

INSPECTION GUIDANCE AND EVALUATION OF LICENSEE ACTIVITIES

Based on audits using the TI, as reported at the Second NRC/ASME Symposium on Pump and Valve Testing, the staff generally found check valves were included in two separate plant activities identified as an inservice testing (IST) program and some variation of a preventive maintenance or reliability program, commonly called the check valve program. In general, the IST programs were organized, complete, and implemented. The benefits of the ASME Code IST requirements and regulatory guidance provided by Generic Letter 89-04 were apparent. The check valve programs were in various stages of development. Some licensees did not have formal program documents delineating check valve activities and interfaces. The check valve programs were driven by general industry guidance. The lack of consistency and specific guidance were evident.

The regional inspectors conducted 14 inspections that included 21 plants in 1992 and 1993. In general, the inspectors found that the licensees were informed on check valve activities and program needs, and most had a designated individual assigned as a check valve coordinator. A number of programs were acceptable.

In general, the inspection conclusions reflected the trial audit outcome that plants were in differing stages of developing and implementing check valve programs. There was very little evidence of trending activities and a number of plants did not have a documented and controlled check valve program. Some licensees initiated formal efforts to develop, update, or assess the effectiveness of plant check valve activities coincident with the announced inspection. The inspections had a positive effect of influencing some licensees to update or develop programs and to review plant check valve activities.

Plants had adequately implemented IST programs. However, there were some discrepancies,

particularly with regard to backflow testing of certain valves.

CHECK VALVE PROBLEMS, PERFORMANCE WEAKNESSES, AND RESEARCH

In order to identify generic problems and evaluate the effects of industry's efforts at improving check valve performance and operational readiness, the staff reviewed the availability of chronological assessments of the industry's experience with check valve failures. A search concluded that the few documents available in this area were inappropriate for the evaluation. The most recent, widely used, and accepted document available was a paper presented at the Electric Power Research Institute (EPRI) Power Plant Valves Symposium II, in October 1988, titled "Check Valve Failure Trends In The Nuclear Industry." The author reviewed nuclear plant reliability data system (NPRDS) failure records for events involving check valve failures for 1985–1987. The staff considered the information provided in this paper to be out of date and inadequate, and questioned some of the conclusions being drawn by industry as a result of a figure in the paper depicting check valve failures as a function of age at failure. The staff asked the Oak Ridge National Laboratory (ORNL) to conduct a more thorough assessment of the historical failure data, characterize the check valve degradation and failure experience, and extend the coverage to 1984–1990. ORNL completed the study and issued *A Characterization of Check Valve Degradation and Failure Experience in the Nuclear Industry* (Casada and Todd, 1993). The report characterizes failures by age, system, valve size, failure mode, extent of degradation, detection method, failure areas, manufacturer, and system operating status. In a cooperative effort, the NIC gave ORNL the opportunity to discuss some of the failure data directly with the involved plant personnel as a means of checking the quality of the failure characterizations. The study shows that the failure rates are related to certain check valve characteristics, features, length of service, and system applications. The failure experience report also indicates that performance and operational readiness can be improved by periodic monitoring, evaluation of the results, and a timely preventive maintenance program when coordinated and tailored to certain valve characteristics and system conditions and application. The report supplies the needed historical baseline to assess valve conditions and trend the effects of industry's efforts to improve check valve performance and operational readiness. Present plans will update the study to include 1991 and 1992 failure and degradation data. Furthermore, the NIC established a task group to review and evaluate the check valve failure report and the annual updates. The staff encourages the NIC organization to continue the annual updating and evaluation beyond 1992. The results provide information to assist in identifying generic problems and to assess the degree of success of industry's efforts in monitoring, programmatic control, and preventive maintenance toward improving check valve performance and reliability.

INDUSTRY IMPROVEMENT EFFORTS AND CODE DEVELOPMENT

NIC, with support from the EPRI Monitoring and Diagnostic (M&D) Center and Nuclear Maintenance Applications Center (NMAC), has been addressing certain check valve issues. The NIC, with support from EPRI's M&D Center, conducted experimental research programs to investigate and demonstrate the application and ability of existing nonintrusive techniques to predict the condition of operating check valves in water and air systems. The research was carried out at the Utah Water Research Laboratory and included ultrasonic, acoustic, magnetic, and eddy current techniques. The water tests were conducted in January and February 1990 and the air tests were conducted in September 1991. Reports on the completed programs were issued to NIC utility members in 1992 and 1993. These and other programs have demonstrated, and documented that certain methods are successful in check valve applications. Nonintrusive methods of monitoring check valve operation have

progressed sufficiently to warrant use in surveillance activities. The EPRI M&D Center also conducts workshops on check valve maintenance and diagnostics.

EPRI/NMAC, with NIC support, updated and issued *Application Guide for Check Valves in Nuclear Power Plants* in April 1993. NIC and EPRI/NMAC are developing a check valve maintenance manual that is needed by the industry and is scheduled for issuance in 1994.

The WGCV OM-22 developed two changes to the ASME/OM Code, Subsection ISTC. One change addressed the use of nonintrusive methods as an acceptable test method regarding inservice testing requirements for check valves. The other change involved sample disassembly and inspection of valves. This change allows the use of disassembly and inspection on a rotating sample basis to determine valve obturator movement for certain check valves when other test methods are impractical.

The WGCV OM-22 also recently proposed an optional change to the ASME/OM Code, Subsection ISTC, requirements to improve valve performance and to optimize testing, examination, and preventive maintenance activities for the purpose of ensuring continued acceptable performance of certain check valves. This change is included in the proposed "Condition Monitoring Program." The basis, justification, and documentation required for electing this option and these activities in lieu of the Code-prescribed testing requirements becomes the owner's responsibility.

STAFF CONCLUSIONS, ACTIVITIES, AND PLANS

The attention and activities of certain industry organizations are currently focused on improving check valve reliability and performance. The NIC, with EPRI's M&D Center and NMAC, and the WGCV OM-22 have taken proactive stands on certain check valve issues that hold promise for improving the performance and operational condition of the valves. The staff will continue to monitor these activities and assess the results. Although immediate regulatory action is not anticipated, check valves do require continued staff and industry attention. The industry's attention should be directed toward a systematic evaluation of the historic and annual assessments of reported failure data and the development of appropriate and justified periodic performance monitoring coupled with timely preventative maintenance intervals.

The staff has extended the use of TI 2515/110 to ensure that check valve programs and activities at most operating plants will be inspected and evaluated.

The staff will continue to monitor the preparation and issuance of the NIC/NMAC check valve maintenance manual and associated NIC guidance on its use in developing preventive maintenance programs. Industry acceptance and the use of the maintenance manual and guidance will be of particular interest to the staff with regard to maintenance rule implementation. In addition, the staff will also continue to implement the other check valve action plan activities. The staff will evaluate the ORNL failure report updates, licensee event reports (LERs), and industry activities to assess improvement trends and any need for new generic requirements or guidance.

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Pressure Locking and Thermal Binding of Gate Valves[a]

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ABSTRACT

The nuclear industry has been aware of the potential for valve inoperability caused by pressure locking and thermal binding for many years. Pressure locking or thermal binding is a common-cause failure mechanism that can prevent gate valve opening on demand, and could render redundant trains of safety systems, or multiple safety systems, inoperable. In spite of numerous generic communications issued by the U.S. Nuclear Regulatory Commission (USNRC) and industry, gate valves in nuclear plant safety-related systems continue to experience pressure locking and thermal binding.

USNRC investigations of gate valve pressure locking and thermal binding events and surveys of licensee evaluations and corrective measures concerning the locking mechanisms indicate that the valve locking is a result of inadequate design consideration under specific system and plant operating conditions. Most valve binding events occurred during infrequent plant evolutions, system transients, or unusual system alignments. Hence, the inadequate design would not necessarily be discovered during plant startup testing or regular surveillance testing. The USNRC staff described the results of its analysis in NUREG-1275, Volume 9. A subsequent survey has found that (a) most licensees had made multiple attempts to address the issue with limited implementation of industry guidance to prevent or correct the problem, (b) three incorrect assumptions were used that prevent licensees from identifying valves susceptible to pressure locking or thermal binding, (c) low-pressure emergency core cooling system valves (low-pressure coolant injection, low-pressure core spray, residual heat removal, and pressurized water reactor containment sump suction) appear most susceptible and risk significant, and (d) a programmatic approach involving system, operations, and component personnel is needed in order to identify the potential for valve locking.

In summary, identifying those valves susceptible to pressure locking and thermal binding is a complex process involving knowledge of components, systems, and plant operations. This paper describes scenarios that cause pressure locking and thermal binding and identifies safety-significant valves susceptible to the phenomena.

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a. This paper was prepared by an employee of the U.S. Nuclear Regulatory Commission. It presents information that does not represent a current staff position. The USNRC has neither approved nor disapproved its technical content.

DISCUSSION

The United States Nuclear Regulatory Commission (USNRC) staff has reviewed several operating events involving pressure locking and thermal binding of gate valves. The staff recently issued NUREG-1275, Vol. 9, *Pressure Locking and Thermal Binding of Gate Valves* (March 1993). This report describes the history of motor-operated valve (MOV) events, technical aspects of the phenomena, consequences on valve operability if locking or binding occur, preventive measures, and safety significance. The most significant aspects of gate valve binding as a result of these phenomena are that such binding is often synonymous with MOV failure to open and inability of the associated safety train or system to perform the safety functions. Thus, pressure locking and thermal binding represent potential common-cause failure that could render redundant trains of certain safety-related systems or multiple safety systems inoperable.

These disc binding problems have been addressed by the USNRC and the nuclear industry since 1977 (see NUREG-1275, Vol. 9). Throughout the 1980s, the industry issued a number of event reports describing safety-related gate valve failure to operate because of disc binding. These failures were attributed to either pressure locking or thermal binding. There were also multiple generic-industry communications with guidance for both identifying susceptible valves and appropriate preventative and corrective measures. However, similar events have continued to occur in the 1990s.

After issuing NUREG-1275, Vol. 9, the USNRC staff visited several licensees to understand the technical issues related to identifying valves susceptible to pressure locking or thermal binding. The issues are both generic and plant-specific. They depend on the nuclear steam supply system vendor, the systems in which they are installed, and the components themselves. The visits also determined the implementation status of previous industry guidance (both identification of susceptible valves and application of preventative and corrective measures). One important observation was that many reviews of pressure locking and thermal binding had been performed; however, there were very few instances where valves had been modified in accordance with industry guidance to alleviate affects of pressure locking.

PHENOMENA

Although the pressure locking and thermal binding phenomena are based on well-known concepts, recognizing which valves are susceptible, and when, requires a thorough knowledge of components, systems, and plant operations. The two necessary features to develop gate valve pressure locking in fluid systems are fluid in the valve bonnet cavity, including the volume between the discs, and a mechanism to cause the bonnet cavity fluid pressure to be greater than considered in the sizing of the valve operator for design-basis accidents. The fluid may enter the bonnet cavity via mechanisms as follows: (a) during normal open and close valve cycling at whatever line pressure exists at the time and (b) a fluid differential pressure across a disc that causes the disc to move slightly away from the seat, creating a path to either increase the fluid pressure or fill the bonnet, if it had been empty, with high-pressure fluid. Gate valve pressure locking in a steam system could develop via a steam line pressure that provides a differential pressure across the disc, as described in Step (b) with a valve configuration that permits condensate to collect and enter the bonnet. In addition, a gate valve bonnet pressurized via steam, but without condensate, could experience pressure locking if the line pressure upstream or downstream of the discs drops significantly. An example would be a power-operated relief valve (PORV) block valve that was closed because of a leaking PORV with a valve that should open after the reactor coolant system pressure decreases. Similarly, a gate valve bonnet pressurized via fluid could experience pressure locking if the line pressure upstream or downstream of the discs drops significantly before the demand to open the valve.

The mechanisms that generally cause higher than anticipated bonnet pressure are (a) connection to a higher pressure system when isolation is

provided only by check valves that easily transmit pressure, even when passing leak tightness criteria, and (b) bonnet volume temperature increase that causes thermal expansion of the confined fluid with a corresponding pressure increase. The temperature increase may result from heatup during plant operation, ambient air temperature rise because of leaking components or pipe breaks (accidents), and thermal conduction and convection through connected piping during the various modes of plant operation. The valve types affected by pressure locking are flexible-wedge, split-wedge, and parallel slide-disc gate valves.

Thermal binding is generally associated with a wedge gate valve that is closed while the system is hot and then allowed to cool before the valve is called to open. The valve body and disc mechanically interfere because of the different expansion and contraction characteristics of the valve body and disc. The different thermal contraction causes the valve seat to create an interference fit with the disc. Thus, the disç is bound so tightly that reopening is either difficult or impossible until the valve is reheated. Solid wedge type gate valves appear most susceptible to thermal binding. However, there is some evidence that flex-wedge gate valves with a high temperature gradient across the discs and certain manufacturing tolerances can also exhibit binding characteristics.

DESIGN BASIS CONSIDERATIONS

The MOVs under consideration are those used to mitigate an accident. This generally involves valve disc motion, open or close, to either isolate fluid flow or permit fluid flow for injection. The isolation function occurs against either pump head pressure and flow, or water, or steam system flow subsequent to a pipe rupture. The open function occurs against pump head pressure and flow. For each function, the loading effects on the disc are similar, and valve operator thrust requirements have been determined by testing and a specific load thrust model using only one disc and seat surface. This situation differs from that developed during pressure locking and thermal binding of flexible-wedge, split-wedge, and parallel slide-disc gate valves.

The pressure locking and thermal binding situations of interest are those in which a valve is closed and must open for fluid injection. The loads that the operator must overcome to open the valve are caused by bonnet cavity pressure or physical interference between the discs and valve seats. This condition may also occur in combination with pump head pressure. Thus, the load sources are different from the usually associated loadings; they act on two discs and seats rather than one disc and seat, and the load source is internal to the valve rather than external (except that contribution from the external pump head pressure).

Pressure locking or thermal binding occur as a result of the valve design characteristics (wedge and valve body configuration, flexibility, and material thermal coefficients) when subjected to specific pressures and temperatures during various modes of plant operation. It appears that neither the valve designer nor user were cognizant of the valve response to certain plant design-basis conditions that could subject these valves to high pressures or temperature variations. However, irrespective of knowledge about valve behavior, determination of the pressures and temperatures should be part of the MOV design bases. Operating experience indicates that this aspect was not considered at many plants. The experience also shows that pressure locking and thermal binding restraining loads can significantly exceed the design-basis accident loads currently used to determine valve operator thrust requirements for some MOVs.

Figure 1 depicts a closed flexible-wedge gate valve with equal pressure shown throughout the bonnet and interconnected volume between the discs. The primary issue is the differential pressure effect across both discs on the actuator thrust required to open the valve. Current procedures determine the actuator thrust to overcome differential pressure across one disc only. Thus, in theory, an internal pressure creating a differential pressure across both discs, which was the same as that across one disc, could double the actuator thrust required to open the valve. This observation

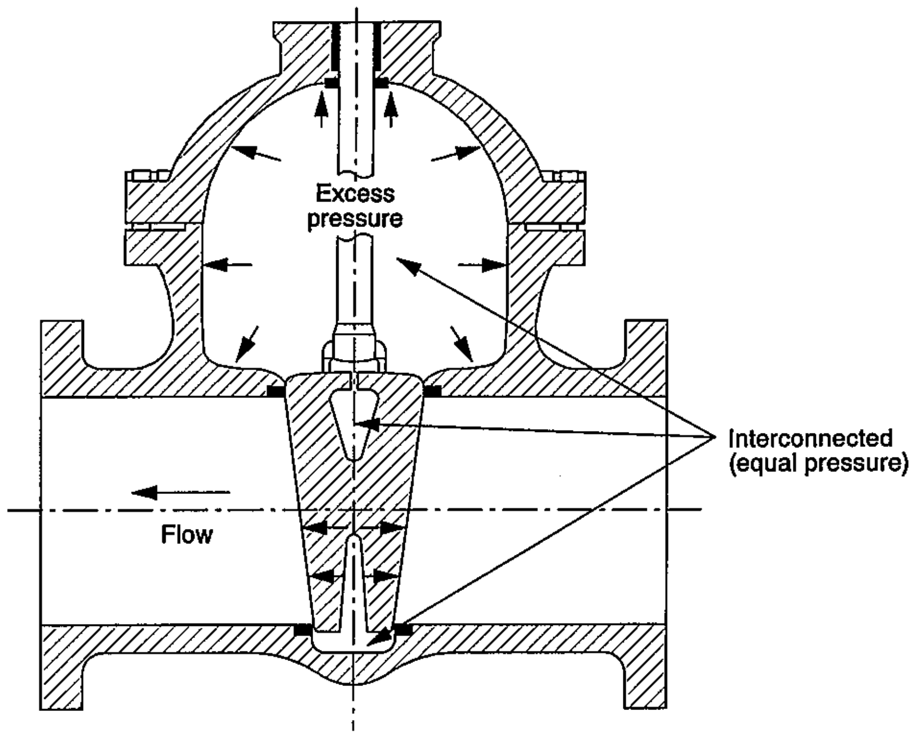

Figure 1. Pressure locking flexible-wedge gate valve.

illustrates conceptually how pressure locking can significantly increase the thrust required to open an actuator. However, the model described does not bound the differential pressure that could be experienced. The actual bonnet pressure and disc differential pressure depends upon how the bonnet becomes pressurized (such as, a connecting high-pressure system or temperature increase caused by ambient air or connected piping), the differential pressure used to size the actuator, and the actual pressure against each disc. This could represent an actuator thrust multiple significantly greater than two. Thus, valve modification may be needed to ensure valve operability.

Based on the differences in which the loads are applied, it appears that testing in conjunction with Generic Letter 89-10 does not replicate the loading conditions for pressure locking and thermal binding. Thus, analytic methods to evaluate loads should be confirmed by appropriate tests.

OPERATING EXPERIENCE AND PREVENTIVE METHODS

Several plants have experienced either pressure locking or thermal binding. These are discussed in NUREG-1275, Vol. 9. The most important message about the events in the NUREG report is that they illustrate how conditions develop or evolve to cause pressure locking and thermal binding rather than identify the most risk significant valves. The following are examples of safety-related gate valves involved in pressure locking events:

- Low-pressure coolant injection (LPCI) and low-pressure core spray (LPCS) system injection valves
- Containment spray system valves
- Residual heat removal (RHR) system, shutdown cooling mode isolation valves

- RHR hot leg crossover isolation valves
- RHR containment sumps and suppression pool suction valves
- High-pressure coolant injection (HPCI) steam admission valves
- RHR heat exchanger outlet valves
- Emergency feedwater isolation valves.
- The following are examples of safety-related gate valves involved in thermal binding events:
- Reactor depressurization system isolation valves
- RHR inboard suction isolation valves
- HPCI steam admission valves
- PORV block valves
- Reactor coolant system letdown isolation valves
- RHR suppression pool suction valves
- Containment isolation valves (sample line, letdown heat exchanger inlet header)
- Condensate discharge valves
- Reactor feedwater pump discharge valves.

Several preventive and corrective measures for pressure locking and thermal binding are discussed in NUREG-1275, Vol. 9, page 7. Each method has limitations with respect to applicability, safety, effectiveness, and cost. Many methods have been used in the past and described in previous generic communications. In general, pressure locking has been alleviated through valve modification to vent the pressure, while procedure changes were used to prevent thermal binding.

IDENTIFYING SUSCEPTIBLE VALVES

USNRC staff discussions with licensees were very helpful in developing an understanding of the conditions, component designs, systems, and operational sequences that impact gate valve susceptibility to pressure locking and thermal binding. This process led to the observation that certain assumptions or perceptions can result in misunderstanding situations that represent potential pressure locking or thermal binding. Three important and incorrect assumptions that exist that hinder identifying valves susceptible to pressure locking or thermal binding:

- Plant records do not show a maintenance or operational history of the problem
- Leakage past an in-line check valve was assumed to be zero
- The review for susceptibility was restricted to normal system operation only.

A typical pressurized-water reactor (PWR) RHR system configuration (shown simplified in Figure 2) illustrates certain valves that can be susceptible to pressure locking during an accident sequence. The valves include hot leg injection, RHR cross-tie to hot leg injection, RHR cross-tie to safety injection, and the containment sump isolation to the RHR pump suction for recirculation. For some valves, the valve safety function may be needed up to several hours after the accident.

The boiling-water reactor (BWR) low-pressure injection system configuration (shown simplified in Figure 3) illustrates the potential pressure locking of the injection valve. This scenario has bonnet pressure increase caused by a leaking check valve with the flow path from the feedwater system followed by subsequent depressurization during a loss-of-coolant accident. Figure 4 illustrates the potential for pressure locking to occur in the suppression pool suction valve caused by heatup through a connection to the hot pipe while the shutdown cooling system is in use.

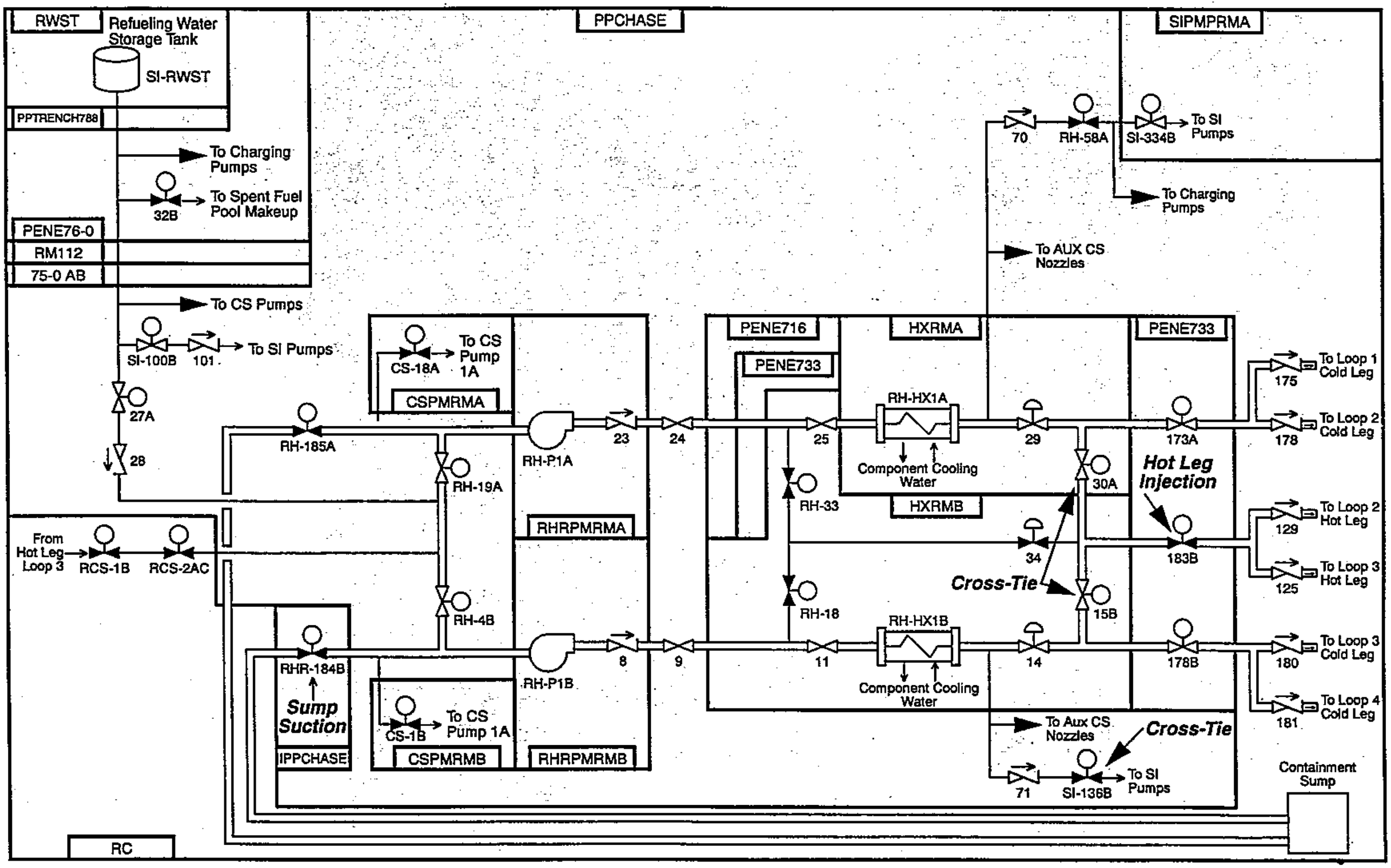

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Figure 2. Residual heat removal system.

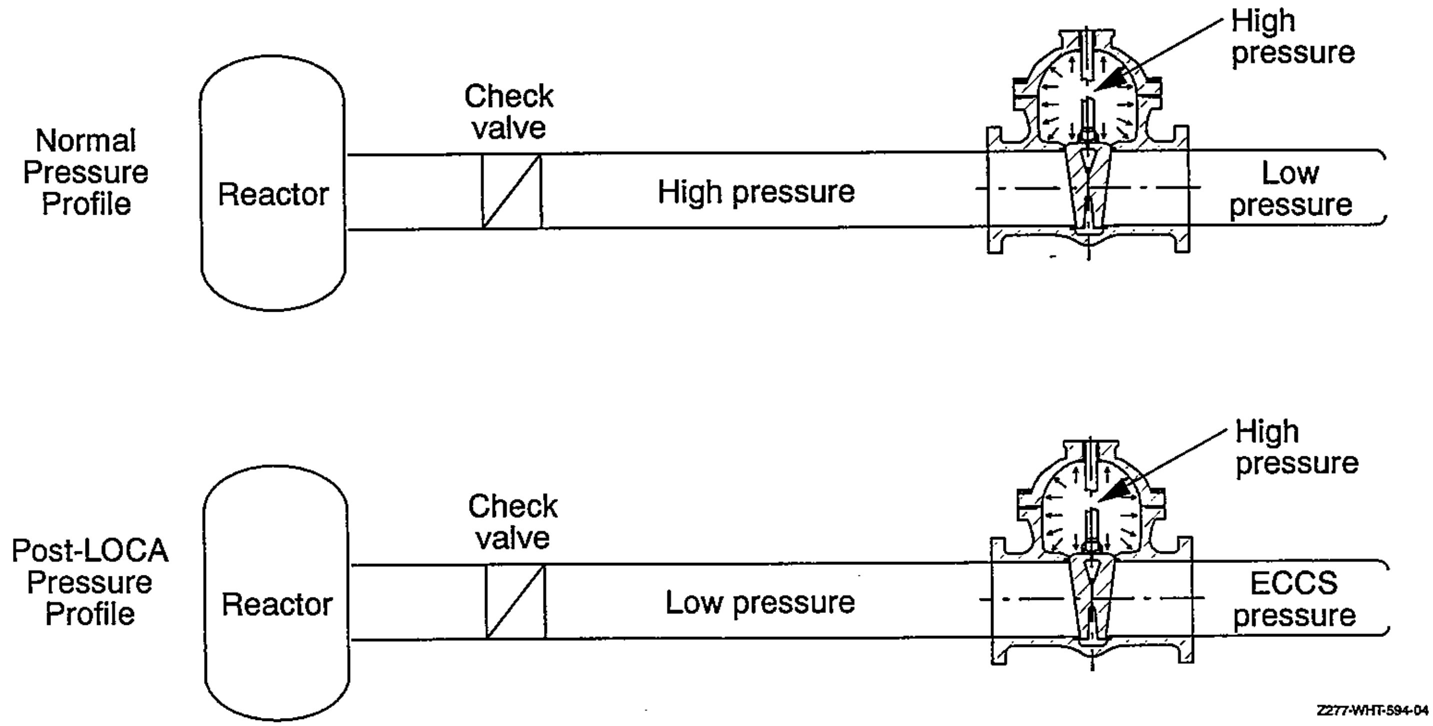
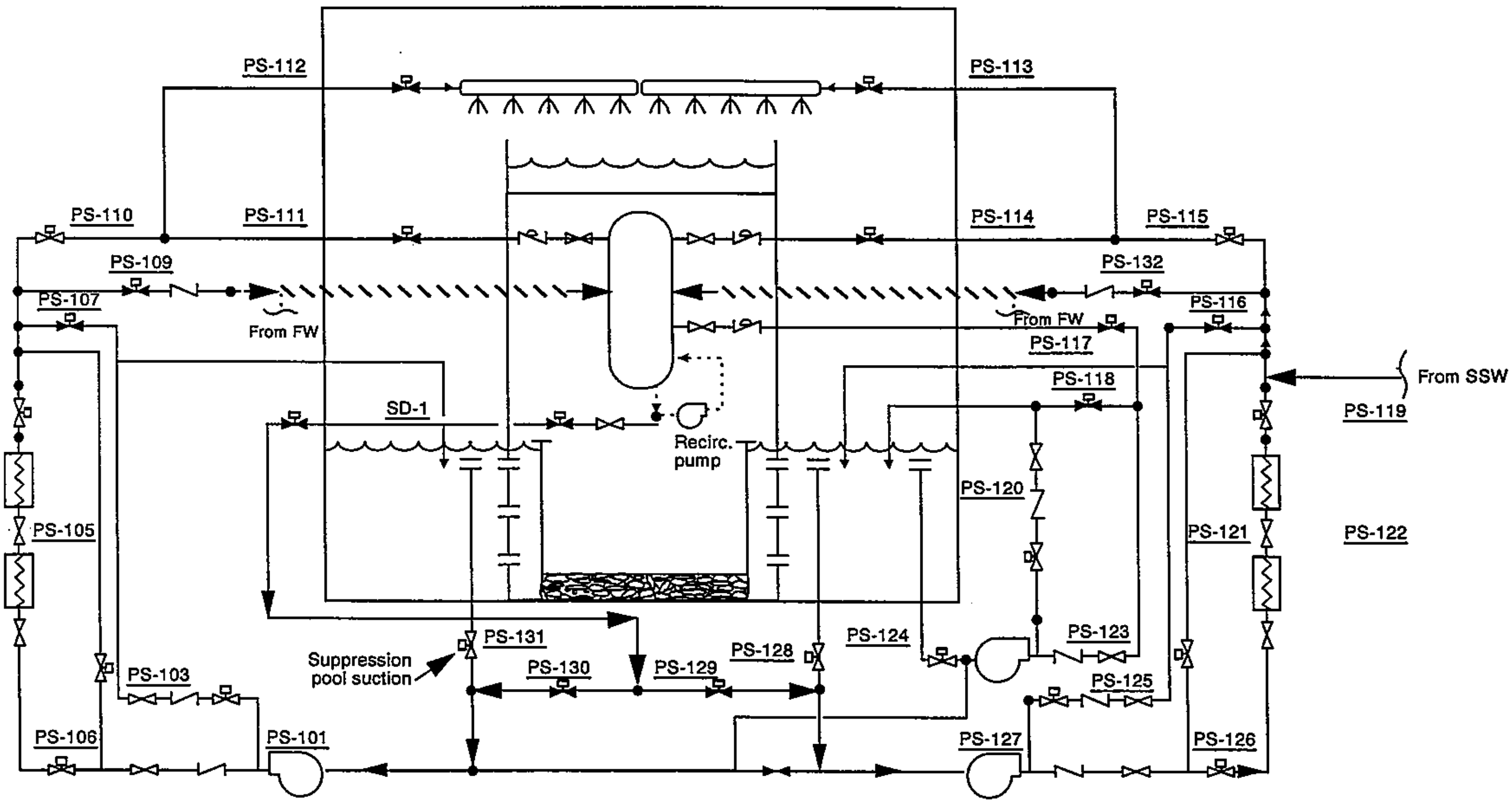


Figure 3. BWR low pressure safety injection.



Valve positions are shown in their standby mode

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Figure 4. BWR shutdown cooling.

Staff reviews and information obtained during discussions with licensee staff led to the recognition that certain safety-significant valves are susceptible to pressure locking or thermal binding. The specific valves affected were found to vary between the reactor type (BWR or PWR) and the nuclear steam supply vendor. The differing design characteristics control both the valves that are closed and the plant operational conditions (pressures and temperatures). Table 1 identify safety-significant, susceptible valves for BWRs, Westinghouse PWRs, Babcock & Wilcox Company PWRs, and Combustion Engineering PWRs, respectively.

SUMMARY

The USNRC staff investigations indicate that identifying valves susceptible to pressure locking or thermal binding is a complex process involving knowledge of components, systems, and plant operations. Component aspects include understanding valve operation, knowledge of valve design that can affect thrust requirements to lift the discs off the seats, and knowledge of the process used to determine actuator thrust requirements. System considerations involve knowledge of system conditions during all modes of plant operation, pump and valve alignments and operations, and knowledge of pump and valve start signals during all modes of operation including transients, accidents, and recovery actions hours after an accident. Operations aspects relate to knowledge of plant operations from startup to shutdown throughout a full fuel cycle to include systems or trains used and when, system temperature and pressure conditions in various modes, interface conditions (especially temperature and pressure) between systems or trains (or modes of a system), and valve proximity to fluid temperature change (heatup or cooldown) or valve exposure to pressure difference. An observation from discussions with licensees was that those most successful in identifying valves susceptible to pressure locking and thermal binding uses an interdisciplinary team composed of valve experts, systems engineers, and plant operations staff.

Valves that are identified as susceptible to these binding phenomena need effective valve modifications or appropriate procedures to ensure operability. There are several preventive and corrective measures. Each method has advantages or limitations with respect to applicability, safety, effectiveness, and cost. Prioritization of valves for preventive or corrective actions may be established with probabilistic risk assessment methods.

Table 1. Safety significant susceptible valves.

Plant type/vendor	Service type	System/conditions
BWRs	Low pressure	LPCI, LPCS (injection)—leaking check valves
		RHR modes—reposition valves
	High pressure	HPCI, HPCS (injection)—leaking check valves
		HPCS (suction)—conduction heatup
		HPCI, RCIC (steam admission)—orientation, condensate
PWR—Westinghouse	Low pressure	Containment sump (suction)—bonnet filled, heatup during LOCA
		Hot leg injection—leaking check valve
		Decay heat removal (cold shutdown plant)—RCS pressure
		ECCS cross-connect/recirculation—RCS pressure
	High pressure	PORV block valve—closed during operation, feed and bleed
PWR—Babcock & Wilcox Co.	Low pressure	Containment sump (suction)—bonnet filled, heatup during LOCA
		Valves for boron precipitation—leaking check valves
		Decay heat removal (cold shutdown plant)—RCS pressure
		LPCI (injection)—leaking check valves
		ECCS cross-connect—leaking check valves
	High pressure	PORV block valve—closed during operation, feed and bleed
		AFW (injection)—leaking check valves
		AFW (admission)—orientation, condensate
PWR—Combustion Engineering (most closed valves are globe)	Low pressure	Containment sump (suction)—bonnet filled, heatup during LOCA
		Decay heat removal (cold shutdown plant)—RCS pressure
		ECCS cross-connect—leaking check valves (not all plants)
	High pressure	PORV block valve—closed during operation, feed and bleed
		AFW (injection)—leaking check valves
		AFW (steam admission)—orientation, condensate
		Containment spray—bonnet filled during startup

Advanced Reactor Pump and Valve Issues[a]

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ABSTRACT

The U.S. Nuclear Regulatory Commission (USNRC) regulations in Title 10 of the Code of Federal Regulations, Part 50.55a (10 CFR 50.55a) incorporates by reference the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code for criteria to conduct inservice testing (IST) of pumps and valves. In Office of the Secretary of the Commission Paper (SECY) 90-016 (dated January 12, 1990), the staff recommended certain criteria to the USNRC to be used to supplement the ASME Code requirements for IST of safety-related pumps and valves for evolutionary advanced light-water reactor (ALWR) designs. In its staff requirements memorandum of June 26, 1990, the USNRC approved the staff's positions as supplemented in the April 27, 1990, staff response to Advisory Committee on Reactor Safeguards comments. This paper discusses the following pump and valve issues for evolutionary ALWR designs: design and qualification of pumps and valves, preoperational testing of pumps and valves, and issues concerning the IST of pumps and valves as stated in SECY-90-016.

INTRODUCTION

The U.S. Nuclear Regulatory Commission (USNRC) regulations in Appendix A to Title 10 of the Code of Federal Regulations Part 50 (10 CFR 50) require that components important to safety be designed and tested to standards commensurate with the importance of the safety functions they must perform. The USNRC regulations in 10 CFR 50.55a incorporate by reference the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requirements to conduct inservice testing (IST) of pumps and valves. However, as discussed in the Office of the Secretary of the Commission Paper (SECY) 90-016 (dated January 12, 1990), "Evolutionary Light-Water Reactor (LWR) Certification Issues and Their Relationship to Current Regulatory Requirements," the staff determined that ASME Code Section XI requirements do not ensure the necessary level of component operability that is desired for evolutionary advanced light water reactor (ALWR) designs. Accordingly, in SECY 90-016, the staff recommended that the USNRC approve the following four requirements for the IST of safety-related pumps and valves beyond the current regulatory requirements in 10 CFR 50.55(a) for ASME Code Class 1, 2, and 3 components:

- Piping design should incorporate provisions for full-flow testing (maximum design flow) of pumps and valves

a. This paper was prepared by an employee of the U.S. Nuclear Regulatory Commission. It presents information that does not represent a current staff position. USNRC has neither approved nor disapproved its technical content.

- Designs should incorporate provisions to test motor-operated valves under design-basis differential pressure

- Check valve testing should incorporate the use of advanced, nonintrusive techniques to address degradation and performance characteristics

- A program should be established to determine the necessary frequency of disassembling and inspecting pumps and valves to detect unacceptable degradation that cannot be detected through the use of advanced, nonintrusive techniques.

The staff concluded that these requirements are necessary to give adequate assurance of component operability.

In its staff requirements memorandum (SRM) of June 26, 1980, the USNRC approved the staff's position, as supplemented in the April 27, 1990, staff response to Advisory Committee on Reactor Safeguards (ACRS) comments. In that response, the staff agreed with the ACRS recommendations to (a) emphasize the provisions of Generic Letter (GL) 89-10 for evolutionary plants, (b) resolve check valve testing and surveillance issues, and (c) indicate how the above requirements will be applied to evolutionary plants. The staff also agreed that the requirements should permit consideration of proposed alternatives for meeting inservice and surveillance requirements.

The staff conducted its evolutionary ALWR reviews considering that SECY 90-016 guidelines on design for testing at design-basis conditions may not be practical in all cases. The staff is requesting that a qualification test (under design-basis differential pressure and flow) be conducted before installation and inservice valve testing be conducted under the maximum achievable differential pressure and flow when it is not practical to achieve design-basis differential pressure and flow during an inservice test. The following sections discuss the agreements reached between the ALWR vendors and the staff for design, qualification, and preoperational testing of the safety-related pumps and valves for demonstrating the adequacy of the capability for the design-basis conditions.

DESIGN AND QUALIFICATION REQUIREMENTS FOR PUMPS

For each pump, the design-basis and required operating conditions (including tests) under which the pump will be required to function will be established. These design (design-basis and required operating) conditions include (a) flow rate and corresponding head for each system mode of pump operation and the required operating time for each mode, (b) acceptable bearing vibration levels, (c) seismic/dynamic loads, (d) fluid temperature, (e) ambient temperature, and (f) pump motor minimum voltage.

The combined operating license (COL) applicant[b] will establish the following design and qualification requirements for pumps and will provide acceptance criteria for these requirements. For each size, type, and model, the COL applicant will perform testing that encompasses all design conditions that demonstrate acceptable flow rate and corresponding head, bearing vibration levels, and pump internals wear rates for the operating time specified for each system mode of pump operation. From these tests, the COL applicant will also develop baseline (reference) hydraulic and vibration data for evaluating the acceptability of the pump after installation. The COL applicant will ensure that the pump specified for each application is not susceptible to the problems noted in operational experience, such as inadequate minimum flow rate and inadequate thrust bearing capacity.

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b. For simplification purposes, the term "COL applicant" will be used to denote either the COL applicant or the COL licensee, although, in practice, tests performed after a COL is issued will be performed by the COL licensee.

requirements described in the plant-specific inservice test program.

DESIGN AND QUALIFICATION REQUIREMENTS FOR MOTOR-OPERATED VALVES

The COL applicant will establish the following design and qualification requirements for MOVs and will provide acceptance criteria for these requirements. By testing each size, type, and model, the COL applicant will determine the torque and thrust (as applicable to the type of MOV) requirements to operate the MOV and will ensure the adequacy of the torque and thrust that the motor-operator can deliver under design (design- basis and required operating) conditions. The COL applicant will also test each size, type, and model under a range of differential pressure and flow conditions up to the design conditions. These design conditions include fluid flow, differential pressure (including pipe break), system pressure, fluid temperature, ambient temperature, minimum voltage, and minimum and maximum stroke time requirements. This testing of each size, type, and model shall include:

- Test data from the manufacturer.
- Field test data for dedication by the COL applicant.
- Empirical data supported by tests.
- Tests (such as prototype) of similar valves that support qualification of the required valve where similarity must be justified by technical data. From this testing, the COL applicant will demonstrate that the results of testing under in situ conditions can be extrapolated to ensure the capability of the MOV to operate under design conditions. The COL applicant will ensure that the structural capability limits of the individual parts of the MOV will not be exceeded under design conditions. The COL applicant will ensure that the valve specified for each application is not susceptible to pressure locking and thermal binding.

PREOPERATIONAL TESTING REQUIREMENTS FOR MOTOR-OPERATED VALVES

The COL applicant will test each MOV in the open and closed directions under static and maximum achievable conditions using diagnostic equipment that measures torque and thrust (as applicable to the type of MOV) and motor parameters. The COL applicant will perform the following activities:

- Test the MOV under various differential pressures and flows up to the maximum achievable conditions.
- Perform a sufficient number of tests to determine the torque and thrust requirements at design conditions.
- Determine the torque and thrust requirements to close the valve for the position at which there is a diagnostic indication of hard seat contact.
- Extrapolate the torque and thrust requirements from the test to design conditions for such parameters as differential pressure, fluid flow, under-voltage, and temperature. The determination of design torque and thrust requirements will also include seismic/dynamic effects for MOVs that must operate during these transients. The design torque and thrust requirements will be adjusted for diagnostic equipment inaccuracies.

The COL applicant will perform the following actions for the point of control switch trip:

- Determine any loss in torque produced by the actuator and thrust delivered to the stem for increasing differential pressure and flow conditions (referred to as load-sensitive behavior).

- Compare the design torque and thrust requirements to the control switch trip torque and thrust, subtracting margin for load-sensitive behavior, diagnostic equipment inaccuracy, control switch repeatability, and degradation.

- Measure the total thrust and torque delivered by the MOV under static and dynamic conditions (including diagnostic equipment inaccuracy and control switch repeatability) to compare with the allowable structural capability limits for the individual parts of the MOV.

- Test for proper control room position indication of the MOV.

The parameters and acceptance criteria for demonstrating that the above functional performance requirements have been met are as follows:

- As required by the safety function, the valve must fully open or fully close or both with diagnostic indication of hard seat contact.

- The control switch settings must provide adequate margin to achieve design requirements including consideration of diagnostic equipment inaccuracy, control switch repeatability, load sensitive behavior, and margin for degradation.

- The motor output capability at degraded voltage must equal or exceed the control switch setting including consideration of diagnostic equipment inaccuracy, control switch repeatability, load sensitive behavior, and margin for degradation.

- The maximum torque and thrust (as applicable for the type of MOV) achieved by the MOV, including diagnostic equipment inaccuracies and control switch repeatability, must not exceed the allowable structural capability limits for the individual parts of the MOV.

- The remote position indication testing must verify that proper disc position is indicated in the control room and in other remote locations relied upon by operators in any emergency situation.

- Stroke-time measurements taken during valve opening and closing must meet minimum and maximum stroke-time requirements.

DESIGN AND QUALIFICATION REQUIREMENTS FOR POWER-OPERATED VALVES

The COL applicant will establish the following design and qualification requirements for power-operated valves (POVs) other than MOVs and will provide acceptance criteria for these requirements (MOV requirements were discussed earlier):

- Determine the force (as applicable to the type of POV) requirements to operate the POV and ensure the adequacy of the force that the operator can deliver under design (design basis and required operating) conditions by testing each size, type, and model.

- Test each size, type, and model under a range of differential pressures.

- Flow conditions up to the design conditions, such as fluid flow, differential pressure (including pipe break), system pressure, fluid temperature, ambient temperature, minimum air supply system (or accumulator) pressure, spring force, and minimum and maximum stroke time requirements. This testing of each size, type, and model shall include test data from the manufacturer, field test data for dedication by the COL applicant, empirical data supported by tests, or tests (such as prototype) of similar valves that support qualification of the required valve where similarity must be justified by technical data. From this testing, the COL applicant will demonstrate that the results of testing under in situ conditions can be used to ensure the capability of the POV to operate under design conditions.

PREOPERATIONAL TESTING REQUIREMENTS FOR PUMPS

The COL applicant will test each pump in each mode of system operation and will vary the pump supply levels to achieve minimum expected suction pressure conditions. These tests will measure discharge pressure, inlet pressure, flow rates, and vibration levels of all accessible bearings.

The parameters and acceptance criteria for demonstrating that the preceding functional performance requirements have been met are as follows:

1. For each design-basis and required operating condition (i.e., each system mode of pump operation), measured values of flow rate and corresponding head will meet or exceed those required by the design, including minimum recirculation flow requirements. These measured values must be conservatively adjusted to allow for instrument loop inaccuracy. Instrument loop inaccuracy for this purpose shall include the calibrated inaccuracy of the sensor and readout device and attributes such as orifice tolerances, tap locations, and process temperatures.

2. Net positive suction head (NPSH) requirements will be met or exceeded for all system modes of pump operation.

3. Acceptable vibration limits for each system mode of pump operation are contained in ASME/ANSI OMa-1988, Part 6. Vibration levels exceeding these limits can be approved by the vendor who supplies the pump.

DESIGN AND QUALIFICATION REQUIREMENTS FOR CHECK VALVES

The COL applicant will establish the following design and qualification requirements for check valves and will provide acceptance criteria for the requirements. By testing each size, type, and model, the COL applicant will ensure the design adequacy of the check valve under design (design-basis and required operating) conditions. These design conditions include:

- All required system operating cycles to be experienced by the valve (numbers of each type of cycle and duration of each type cycle)
- Environmental conditions under which the valve will be required to function
- Severe transient loadings expected during the life of the valve, such as waterhammer or pipe break
- Lifetime expectation between major refurbishments
- Sealing and leakage requirements
- Corrosion requirements
- Operating medium with flow and velocity definition
- Operating medium temperature and gradients
- Maintenance requirements
- Vibratory loading
- Planned testing and methods
- Test frequency
- Periods of idle operation.

The design conditions may include other requirements that are identified during detailed design of the plant systems. This testing of each size, type, and model shall include:

- Test data from the manufacturer.
- Field test data for dedication by the COL applicant.

- Empirical data supported by tests.

- Tests (such as prototype) of similar valves that support qualification of the required valve where similarity must be justified by technical data. The COL applicant will ensure proper check valve application, including selection of the valve size and type based on the system flow conditions, installed location of the valve with respect to sources of turbulence, and correct orientation of the valve in the piping (i.e., vertical versus horizontal) as recommended or required by the manufacturer. The COL applicant will ensure that valve design features, material, and surface finish will accommodate nonintrusive diagnostic testing methods available in the industry.

- The COL applicant will also ensure that flow through the valve can be determined from installed instrumentation and that valve disc positions can be determined without disassembly, such as by use of nonintrusive diagnostic methods. Valve internal parts are designed with self-aligning features to ensure correct installation. The COL applicant will compare the maximum loading on the check valve under design-basis and the required operating conditions with the allowable structural capability limits for the individual parts of the check valve. The qualification acceptance criteria noted above will include baseline data developed during qualification testing and will be used to verify the acceptability of the check valves after installation.

PREOPERATIONAL TESTING REQUIREMENTS FOR CHECK VALVES

The COL applicant will test each check valve in the open or closed direction or both, as required by the safety function, under all normal operating system conditions. To the extent practical, the valves will be tested under fluid temperature conditions that would exist during a cold shutdown as well as under fluid temperature conditions that would be experienced by the valve during other modes of plant operation. The valves will be tested to determine (a) the flow needed to open the valve to the fully open position, (b) the effects of rapid pump starts and stops as required by expected system operating conditions, and (c) any other reverse flow conditions that may be required by expected system operating conditions. The COL applicant will examine the disc movement during valve testing and verify the leak-tightness of the valve when fully closed. By using methods such as nonintrusive diagnostic equipment, the COL applicant will examine the open valve disc stability under the flow conditions during normal and other required system operating conditions.

The parameters and acceptance criteria for demonstrating that the preceding functional performance requirements have been met are as follows:

- During all test modes that simulate expected system operating conditions, the valve disc fully opens or fully closes as expected based on the direction of the differential pressure across the valve

- The leak-tightness of the valve when it is fully closed is within established limits, as applicable

- The valve disc positions can be determined without disassembly

- Valve testing must verify free disc movement whenever the disc is moving to and from the seat

- The disc is stable in the open position under normal and other required system operating fluid flow conditions

- Valve design features, material, and surfaces accommodate nonintrusive diagnostic testing methods available in the industry

- Piping system design features accommodate all the applicable check valve testing

Guidelines for Optimizing Safety Benefits in Ensuring the Performance of Motor-Operated Valves

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ABSTRACT

For the past several years, both the U.S. nuclear power industry and the U.S. Nuclear Regulatory Commission have devoted significant attention and resources toward improving the performance of motor-operated valves (MOVs).

Clearly, the level of attention and resources given to MOVs has resulted in an improved understanding of the design, operation, and maintenance of these components. The enhanced knowledge of these types of valves provides the engineering basis for maintaining reliable performance over their service lives. The accumulation of this knowledge, however, has come at a tremendous expense that continues to absorb industry and regulatory attention and resources. Given that the contribution to safety of individual MOVs varies widely, a number of questions have been raised concerning whether this expenditure results in commensurate benefits and to what extent this expenditure should continue.

This paper proposes to apply resources in a manner that is commensurate with the safety-significance of individual MOVs. This approach should not only lead to increased levels of confidence in plant safety, but should also result in a more efficient use of industry and regulatory resources. This paper recommends using a graded approach that can optimize the safety benefits in ensuring MOV performance. The graded approach is founded on a blend of probabilistic and deterministic methods.

The approach consists of three main steps:

- Rank MOVs according to their importance to safety using probabilistic safety assessment (PSA) techniques
- Prioritize MOVs into importance categories using a blend of PSA ranking information and deterministic insights
- Apply specific requirements to each group of MOVs.

This approach would allow more rational decision-making and more efficient use of resources, which are central to optimizing safety benefits.

- Ensure that the structural capability limits of the assembly and the individual parts of the POV will not be exceeded under design conditions.

- Ensure that packing adjustment limits are specified for the valve for each application so that it is not susceptible to stem binding.

- Ensure that the valve specified for each application is not susceptible to pressure locking and thermal binding.

PREOPERATIONAL TESTING REQUIREMENTS FOR POWER-OPERATED VALVES

The COL applicant will test each POV in the open and closed directions under static and maximum achievable conditions using diagnostic equipment that measures or provides information to determine total friction, stroke time, seat load, spring rate, and travel under normal pneumatic or hydraulic pressure (as applicable to the type of POV), and minimum pneumatic or hydraulic pressure. The COL applicant will test the POV under various differential pressure and flow up to maximum achievable conditions and will perform a sufficient number of tests to determine the force requirements at design conditions. The COL applicant will determine the force requirements to close the valve for the position at which there is a diagnostic indication of full valve closure (as required for the safety function of the applicable valves). The determination of design force requirements will be made for such parameters as differential pressure, fluid flow, minimum pneumatic or hydraulic pressure, power supply, temperature, and seismic/dynamic effects for POVs that must operate during these transients. The design force requirements will be adjusted for diagnostic equipment inaccuracies.

The COL applicant will measure the total force delivered by the POV under static and dynamic conditions (including diagnostic equipment inaccuracies) to compare to the allowable structural capability limits for the assembly and individual parts of the POV. The COL applicant will test for proper control room position indication of the POV.

The parameters and acceptance criteria for demonstrating that the above functional performance requirements have been met are as follows:

- As required by the safety function, the valve must fully open or fully close or both with diagnostic indication of hard seat contact.

- The assembly must demonstrate adequate margin to achieve design requirements, including consideration of diagnostic equipment inaccuracies and margin for degradation.

- The assembly must demonstrate adequate output capability of the power-operator at minimum pneumatic or hydraulic pressure or electrical supply (or loss of motive force for fail-safe positioning) with consideration of diagnostic equipment inaccuracies and margin for degradation.

- The maximum force (as applicable for the type of POV) achieved by the POV, including diagnostic equipment inaccuracies, must not exceed the allowable structural capability limits for the assembly and individual parts of the POV.

- The remote position indication testing must verify that proper disc position is indicated in the control room and in other remote locations relied upon by operators in any emergency situation.

- Stroke-time measurements taken during valve opening and closing must meet minimum and maximum stroke-time requirements.

- For solenoid-operated valves (SOVs), the Class 1E electrical requirements are to be verified. The SOV should be verified to be capable of performing at design requirements for either normally energized or deenergized operation and rated appropriately for the electrical power supply amperage and voltage.

- Provide leak-tight seating which must meet a specified maximum leakage rate, or meet a leakage rate to ensure an overall containment maximum leakage.

CONCLUSION

To ensure the necessary level of component operability that is desired for evolutionary ALWR designs, the staff conducts its IST review in accordance with the requirements of the ASME Code supplemented by the USNRC-approved requirements for IST of pumps and valves contained in SECY 90-016. Further, to ensure the adequacy of the component capability for the design-basis conditions, the staff's evaluation of evolutionary ALWR pump and valve issues also includes the design, qualification, and preoperational testing requirements discussed in this paper.

Risk-Based Approach for Prioritizing Motor-Operated[a] Valves

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ABSTRACT

The United States Nuclear Regulatory Commission issued Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance" in June 1989. This regulatory document was issued because of the concern for the performance of motor-operated valves (MOVs) under accident loads. The GL 89-10 requests licensees to develop a plan to ensure that safety-related MOVs will accomplish their functions under design basis loads. It also requests licensees to perform design-basis flow tests on the MOVs to establish actual thrust requirements where practicable. In addition, it is recommended that the MOVs be periodically verified to ensure that they will perform their functions throughout the life of the plant.

This paper identifies an approach by which MOVs can be prioritized based on risk importance to fulfill the periodic verification part of GL 89-10. Also, schedules for tests and maintenance of MOVs can be established based on their risk contributions. Those MOVs having the largest impact on plant safety can be grouped and then reverified (tested) and maintained at more frequent intervals. Those MOVs with lower impacts on plant safety can be placed in a second group and reverified and maintained at longer periodic intervals. A third group of safety-related MOVs would contain those that have the lowest impact on plant safety. This last group would be reverified and maintained at even longer intervals. This approach for prioritizing MOVs and establishing groups for scheduling reverification tests and maintenance intervals can be cost effective and can aid in optimizing resources for implementing GL 89-10 for the remaining life of the plant.

BACKGROUND

On June 28, 1989, the U.S. Nuclear Regulatory Commission (USNRC) issued Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance." The reason for issuing GL 89-10 was that assessments of the reliability of safety-related MOVs, based on extrapolations of the available information from valve surveillances at that time, indicated that more than expected MOV malfunctions were occurring and that additional measures should be taken to ensure operation under design-basis conditions for the life of the plant. One of the main items identified in GL 89-10 is that licensees need to periodically verify torque switch settings to ensure that MOVs will accomplish their intended

a. This paper was prepared by an employee of the U.S. Nuclear Regulatory Commission. It presents information that does not represent a current staff position. USNRC has neither approved nor disapproved its technical content.

functions over the life of the nuclear power plants in the United States.

The intent of periodic verification is to ensure that the licensees consider the effects of aging degradation that can cause reduced performance of motors, operators, and valves after long periods. These aging degradations can cause malfunctions and result in premature trips of the MOVs such that discs can stop at partial stroke positions.

The licensees have expended significant resources to implement GL 89-10, and they are investigating ways to make the periodic verification efforts more cost effective. Therefore, in December 1992, some licensees inquired whether the USNRC licensing office would be receptive to risk-based approaches for identifying MOVs most important to plant safety. The plan is that most of the resources could be devoted to these most important MOVs. The USNRC licensing office subsequently stated that the USNRC is receptive to risk-based approaches for identifying the most important MOVs; however, the USNRC also stated that this approach should not be the basis for eliminating any safety-related MOVs from GL 89-10 programs (see Supplement 6 to GL 89-10).

At that time, the USNRC Office of Nuclear Regulatory Research was requested to assist the licensing office in evaluating this approach and to identify problems that might typically be encountered during the performance of a risk-based analysis.

This paper describes an approach that was used to identify and prioritize the most risk-important MOVs in a typical pressurized water reactor (PWR) plant as an aid for meeting the periodic verification part of GL 89-10. During the performance of this analysis, problem areas were identified and are listed in the Conclusions section of this paper. Other observations were made, and these are also reported in the Conclusions section.

DISCUSSION

In 1990, a methodology[b] was developed for the USNRC Office of Nuclear Regulatory Research that permits time-dependent aging rates to be incorporated into typical probabilistic risk assessment (PRA) failure rate models. Current PRA models use constant failure rates for the same components in the entire plant. Because many of the same components (such as MOVs) are scattered throughout the entire plant, it is apparent that not all the same components have the same failure rates. This new methodology permits the inclusion of different failure rates for any of the components. In addition, one of the strong points of this methodology is that the effects of single component aging as well as multiple component aging (resulting from a common cause) and their interactions can also be evaluated. Appropriate failure rates can be identified and the effects on changes to core damage frequency (CDF) can be determined. The component(s) having the largest effect on changes in CDF can then be conveniently identified and prioritized. Reductions in core damage resulting from component replacements or maintenances can also be evaluated using the same methodology. A very important feature of this method is that existing PRA models can be used to determine the effects of aging on plant risk with some reservations. (See items 1 through 7 under Conclusions.)

Analysis

The application of this methodology, including the determination of time-dependent failures, can be complicated; however, assumptions can be made to simplify the problem of identifying which MOVs are most important for safety.

Assumptions. As stated above, for a time-dependent analysis, the actual failure rates would need to be determined. Instead of determining the actual failure rates, for this analysis it will be

b. W. E. Vesely, R. E. Kurth, S. M. Scalzo, *Evaluations of Core Melt Frequency Effects Due to Component Aging and Maintenance*, NUREG/CR-5510, June 1990.

assumed that each of the MOVs will fail (failure probability of unity) and the impact that each MOV failure has on the change in core damage is to be determined. Redundant line MOVs can also be assumed to fail.

By assuming a failure probability of unity for a particular MOV, the question addressed is "How important is this MOV to the safety of the plant?" Because the idea of risk-based prioritization for the application described in this paper is to devote resources to those MOVs that are most important, an assumption such as this (i.e., failure probability of unity) is acceptable and conducting a PRA is less complicated.

Results

An analysis of a typical PWR plant in the United States was performed using the methodology and assumptions identified above. Table 1 lists the MOV identification number and MOV system locations, respectively.

Single MOV Failures. For this part of the analysis, each MOV is assumed to fail, while all the other MOVs retain their original assumed failure rates equivalent to 0.003 failures per demand. The constant failure rate equivalent to 0.003 failures per demand has been used in typical PRAs by the PWR licensees. The effect of a single MOV failure on the change in CDF is then determined. Each successive safety-related MOV is allowed to fail, and the impact on change to CDF determined for each MOV failure. After all single MOVs have been evaluated, the same analysis is repeated for multiple MOVs that fail as a result of a common cause.

Table 2 lists those MOVs (based on single failures) having the largest impact on plant safety. Specifically, the table shows that failure of either MOV LPR-1862A or LPI-1890C would increase the baseline CDF by a factor of 5. The baseline CDF is the value calculated when all components in a typical PRA model are assigned their respective constant failure rates. Failure of the MOVs identified in the remaining list shows that the CDF would increase by factors of only 3 or 4.

Failures of MOV Pairs. If the analysis were to end at this point, one might conclude that very little "periodic verification" would be required to ensure safety of the plant through its remaining life. Also, the analyst would likely come to the conclusion that although an increase of 5 in the CDF is of concern, immediate steps would not be required for periodic verification of the two MOVs to fulfill GL 89-10. The analyst would be correct in interpreting the results; however, the analyst would arrive at different conclusions when multiple MOVs are allowed to fail simultaneously. The most simple example of this condition occurs in redundant pipes where safety-related MOVs are installed. The justification for allowing two MOVs in redundant piping to fail simultaneously is that these two valves are likely to be identical—same manufacturer, size, and

Table 1. System and event codes (PWR).

System		Failure	
Code	Name	Code	Name
ACC	Accumulators	FC	Loss of function
HPI	High pressure safety injection system	FT	Failure to transfer
LPI	Low pressure recirculation system	PG	Plugged
LPR	Primary pressure relief system		
PPS	Low pressure safety injection system		

Table 2. CDF importances of individual MOVs (PWR).

Valve identifier	CDF relative importance
LPR-MOV-FT-1862A	5
LPI-MOV-PG-1890C	5
ACC-MOV-PG-1865C	4
ACC-MOV-PG-1865B	4
LPR-MOV-FT-1860A	3
LPR-MOV-FT-1890A	3
PPS-MOV-FC-1535	3
PPS-MOV-FC-1536	3
HPI-MOV-FT-1350	3
LPR-MOV-FT-1862B	1
LPR-MOV-FT-1860B	1
HPI-MOV-FT-1115C	1
HPI-MOV-FT-1115E	1
LPR-MOV-FT-1890B	1
HPI-MOV-FT-1115B	1
HPI-MOV-FT-1115D	1

type (including motor-operator). If the torque switches for one of these MOVs are not set properly to fulfill GL 89-10, it is also highly probable that the torque switches in the redundant MOV will not be set properly. Also, both MOVs are located in the same environment and both would be affected equally.

Table 3 shows the results of the PRA for the MOV pairs evaluation. The failures of MOVs PPS-1535 and PPS-1536 cause the CDF to increase by a factor of 700. Failures of some of the other MOV pairs on the list also impact the CDF significantly. Other failures of MOV pairs increase CDF by factors less than 5 and are not included in Table 3. Note that the highest ranking pair of MOVs show up in the middle of the list in Table 2. In addition, some MOVs in Table 2 are not identified in Table 3. This case illustrates the USNRC's major concern with MOV prioritization, that is the prioritized list of important MOVs (for a particular nuclear power plant) should be reasonably the same regardless of the method(s) used to develop the list. This means that important MOVs should not be inadvertently excluded from the prioritized list nor should the level of risk importance of a particular MOV be underestimated as would be the case if only the effects of single MOV failures are analyzed.

It is apparent that simultaneous, multiple MOV failures can be serious. Therefore, it would be advantageous for licensees to periodically verify that those MOVs contained in Table 3 are set up properly. The 16 MOVs listed in Table 3 represent about 10% of the safety-related MOVs in a plant. Therefore, a utility might proposed that verifying these 16 MOVs more frequently would be a reasonable approach to satisfying this part of GL 89-10. A test schedule developed using only Table 2 data may put a plant at high risk if periodic verification is extended to long intervals for the high risk important MOVs.

The failure of MOV pairs was investigated to address common cause effects. If there are redundancies of more than two MOVs in a plant, higher combinations of MOVs simultaneously failing would also need to be considered. The methodology identified earlier can be used to analyze the latter case.

Modifications to Prioritized List of MOVs. The analysis completed thus far considers failures of single MOVs and pairs of redundant MOVs. For the list shown in Table 3 to be complete, it would now be necessary to consider cascading effects. Cascading describes the effect that a failed MOV would have on the performance of other components. Therefore, this second component would also be allowed to fail. Because a failed MOV can prevent another important component from fulfilling its design-basis function, this MOV's impact on CDF should also include the impact of causing the second component to fail. The total importance of this MOV would then be determined from summing the changes in CDF resulting from failure of both components. To consider these effects, the analyst would assume specific MOVs to fail followed by the influence of each MOV failure on

Table 3. CDF importances of pairs of MOVs (PWR).

Valve pair		CDF relative importance
PPS-MOV-FC-1535	PPS-MOV-FC-1536	700
LPR-MOV-FT-1862A	LPR-MOV-FT-1862B	80
LPR-MOV-FT-1860A	LPR-MOV-FT-1862B	50
LPR-MOV-FT-1860B	LPR-MOV-FT-1862A	50
HPI-MOV-FT-1115C	HPI-MOV-FT-1115E	30
LPR-MOV-FT-1890A	LPR-MOV-FT-1890B	30
LPR-MOV-FT-1860A	LPR-MOV-FT-1860B	30
HPI-MOV-FT-1115B	HPI-MOV-FT-1115D	30

other important components, such as pumps or electrical components. To accomplish this, it would be necessary to consider the design-basis conditions for each MOV and the location of the other component (in system or proximity). The analysis would be completed in the same manner as the MOV pairs.

It is conceivable that the resulting changes in CDF from cascading effects would be as large as or even greater than the values shown in Table 3. If this is the case, it would be concluded that these additional MOVs should be part of the prioritized list.

This latter scenario would be followed until all potential MOV interactions with other components have been evaluated.

Some existing PRA models may not have all MOVs covered by GL 89-10 in their fault and event trees. Therefore, these MOVs will not be included in the PRA model and their effects on CDF cannot be determined. For these cases, the MOVs should be included in the prioritized list. For example, containment isolation (MOVs) may be included in Level 2 PRA models that calculate radiological release frequencies, but not in Level 1 PRA models that calculate CDF but not releases. For these cases, the MOVs should be included in the prioritized list unless it can be shown otherwise.

The final list of all safety-related MOVs can be divided into groups based on their risk importances. The highest priority group would require more frequent verification tests. A second group of MOVs, those having minor impacts on plant risk, could be tested after longer operation intervals. A third group of MOVs, those having low impacts on plant risk, could be tested after still longer operating periods. The grouping described above would provide the basis for proportioning the resources in a cost-effective manner. Most of the resources would be devoted to the highest priority MOVs, while smaller amounts of resources would be devoted to the lower priority MOVs.

CONCLUSIONS

This effort was undertaken to determine whether MOVs can be ranked using risk-based technology. To accomplish this, simplifying assumptions were made. For this approach, it became clear that to obtain an accurate list if MOVs,certain guidelines are important. The following guidance[c] identifies the areas that should

c. Guidance from "Prioritization of Motor-Operated Valves Based on Risk Importances," W. E. Vesely and G. H. Weidenhamer, *Presented at the Twenty-First Water Reactor Safety Information Meeting, Bethesda, MD, October 26, 1993.*

be considered when MOVs are ranked in accordance with this method:

1. The MOVs included in the PRA are only a subset of those addressed by GL 89-10.

2. The particular failure modes addressed by GL 89-10 need to be those covered by the PRA.

3. Common cause failures among MOVs as treated in the PRA may be inadequate for GL 89-10 response.

4. PRA importance prioritizations of MOVs needs to consider joint (multiple) MOV importances.

5. MOVs may be unimportant for core damage frequency prevention but may be important for consequence mitigation, shutdown risk control, or when external events are considered.

6. The cascading effects of MOV failures may not be adequately addressed in the PRA.

7. Truncations in the PRA may cause MOV importances to be underestimated.

8. The MOV prioritization criteria and test scheduling criteria need to account for the associated risk impacts.

9. The prioritized groupings of MOV dynamic tests and MOV test schedules need to be validated for their risk control.

10. To develop a complete resource response to GL 89-10, the PRA evaluations need to be integrated with deterministic evaluations.

Note: The NRC will publish the report of this work in September 1994.

Session 4B

Innovative Valve Testing

Session Chair
Thomas Parrent
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Acoustic Emission Testing of Piston Check Valves

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ABSTRACT

Based on test experience at Comanche Peak Unit 1, an acoustic emission data evaluation matrix for piston check valves has been developed. The degradations represented in this matrix were selected based on Edwards piston check valve failure data reported in the Nuclear Plant Reliability Data System. Evidence to support this matrix was collected from site test data on a variety of valve types. Although still under refinement, the matrix provides three major attributes for closure verification, which have proven useful in developing test procedures for inservice testing and preventing unnecessary disassembly.

INTRODUCTION

The Comanche Peak Check (CPSES) Valve Reliability Program (CVRP) was implemented in the spring of 1991, before the first refueling outage on Unit 1, in response to the Institute of Nuclear Power Operations SOER 86-03. The program, which includes 298 check valves from Units 1 and 2, emphasizes condition-directed disassembly; candidates are selected by nonintrusive test results.

There are 74 piston check valves (37 per unit) in the CVRP. All are manufactured by Edwards Valves and represent the three basic Edwards[a] numbers: 838Y, 36174, and 36164. (The last one is a stop check with the basic operational configuration of a typical piston check valve.) The valves range in size from 1 to 2 in. and are located in the following plant systems: chemical and volume control, diesel generator air start, and component cooling water (Tables 1 and 2).

Of these 74 valves, all but six (three for each unit) have been nonintrusively monitored; the majority have multiple test data available. Acoustic emission (AE) has been the primary technique used to date; however, ac and dc magnetic flux technologies have been introduced recently on a case-by-case basis to supplement the AE data.

a. Edwards Valves, Inc., *Valve Catalog and Application Manual*, 2nd Edition, pp. G11 and G14.

CLOSURE VERIFICATION

Definition of AE Test Goals

During the past 1-1/2 years, CPSES has begun using AE for inservice test (IST) closure verification on the majority (29 out of the 37 per unit) of these valves. In order to develop an adequate AE test procedure with minimal experimentation, it was necessary to outline the data characteristics that would determine an acceptable AE closure test. The following features (closure verification attributes) were selected:

1. Defined impact associated with a change in flow (Figure 1B)

2. An obvious change in steady-state (pre- versus post-event) impact levels (Figure 1A)

3. Evidence of rubbing or movement (low frequency activity) within the valve internals during the closure event (Figure 1C).

In addition, representative plant data were expected to be available to support the conclusion of the AE test (Figure 2).

Table 1. Piston check valves included in CPSES Check Valve Reliability Program.

Unit 1 Tag No.	Description	Edwards model	AE in IST	In series
1CS-8377	RCS Aux Spr to Pzr	2-3674F316T1	X	—
1CS-8487	BA Xfer Pmp 1-01 disch	2-3674F316T1	—	—
1CS-8473	BA Xfer Pmp 1-02 disch	2-3674F316T1	—	—
1CS-8480A/B	CCP Recirc	2-3674F316T1	—	—
1CS-8350A/B/C/D	RCP Seal Wtr Inj	2-3674F316T1	X	X
1CS-8367A/B/C/D	RCP Seal Wtr Inj	2-3674F316T1	X	X
1CS-8368A/B/C/D	RCP Seal Wtr Inj	2-3674F316T1	X	X
1CS-8443	BA to CVCS BA Blendr	2-3674F316T1	—	—
1CS-8429	RMUW to CVCS BA Bldr	2-3674F316T1	—	—
1DO-0058 thru 0065	DG Strt Air Rcvr In/Air Dryer Out	1-1/2-838YT1	X	X
1CC-0646,657, 687, 694, 1075-1078	RCP ThBr Clr CCW Sply (Stop CkV)	2-3664T1 2-B36164T3 2-B36164T1	X	X
1CC-0629	RCP Clr CCW Ret Hdr Rlf	2-838YT1	—	—
1CC-0831	RCP ThBrClr CCW Ret Hdr	1-3674T1	—	—

Table 2. Piston check valves in Units 1 and 2.

TOTAL: 37 valves (per unit)

(1) only Unit 1 tag numbers listed

Installed Model	Current Designation	Unit 1	Unit 2
2-3674F316T1	36174	19	19
1-1/2-838YT1	838Y	8	8
2-3664T1	36164	4	4
2-B36164T3	36164	4	0
2-B36164T1	36164	0	4
2-838YT1	838Y	1	1
1-3674T1	36174	1	1
Total per unit		37	37

A 20-second downloaded event limitation was imposed by our software (QUICKCHECK)[b]; however, this was not considered a handicap because most, if not all, of the test opportunities capable of providing the required data lasted less than 20-seconds. In fact, establishing a specific downloaded test duration is an advantage for standardization of analysis activities.

b. Liberty Technologies, *QUICKCHECK User Manual*, Specification XCQ-1-UM-02.

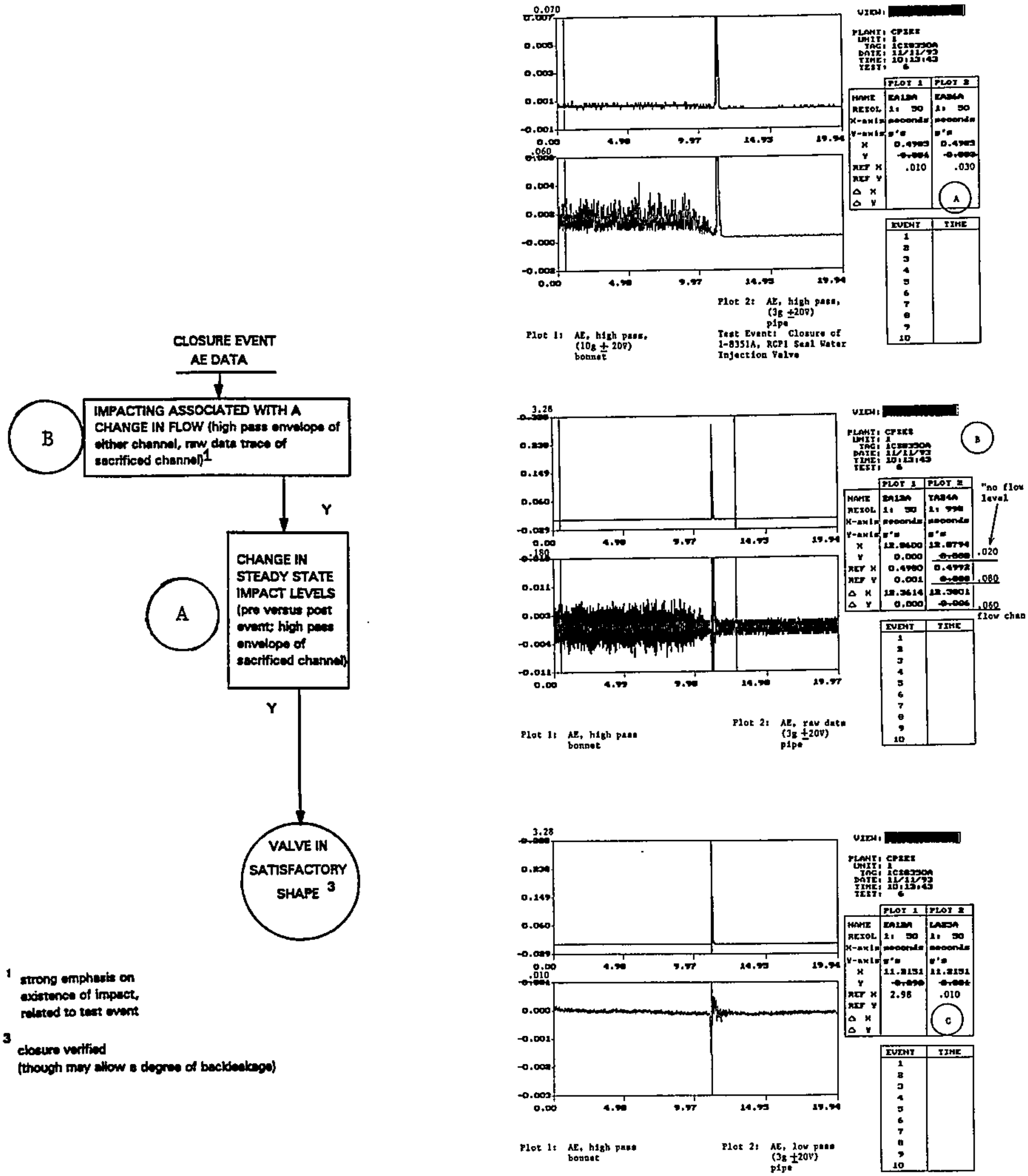


Figure 1. Closure verification attributes, as met during testing of reactor coolant Pump No. 1 seal injection check Valve 1CS-8350A (third in a series of three) (Compare with Figure 12).

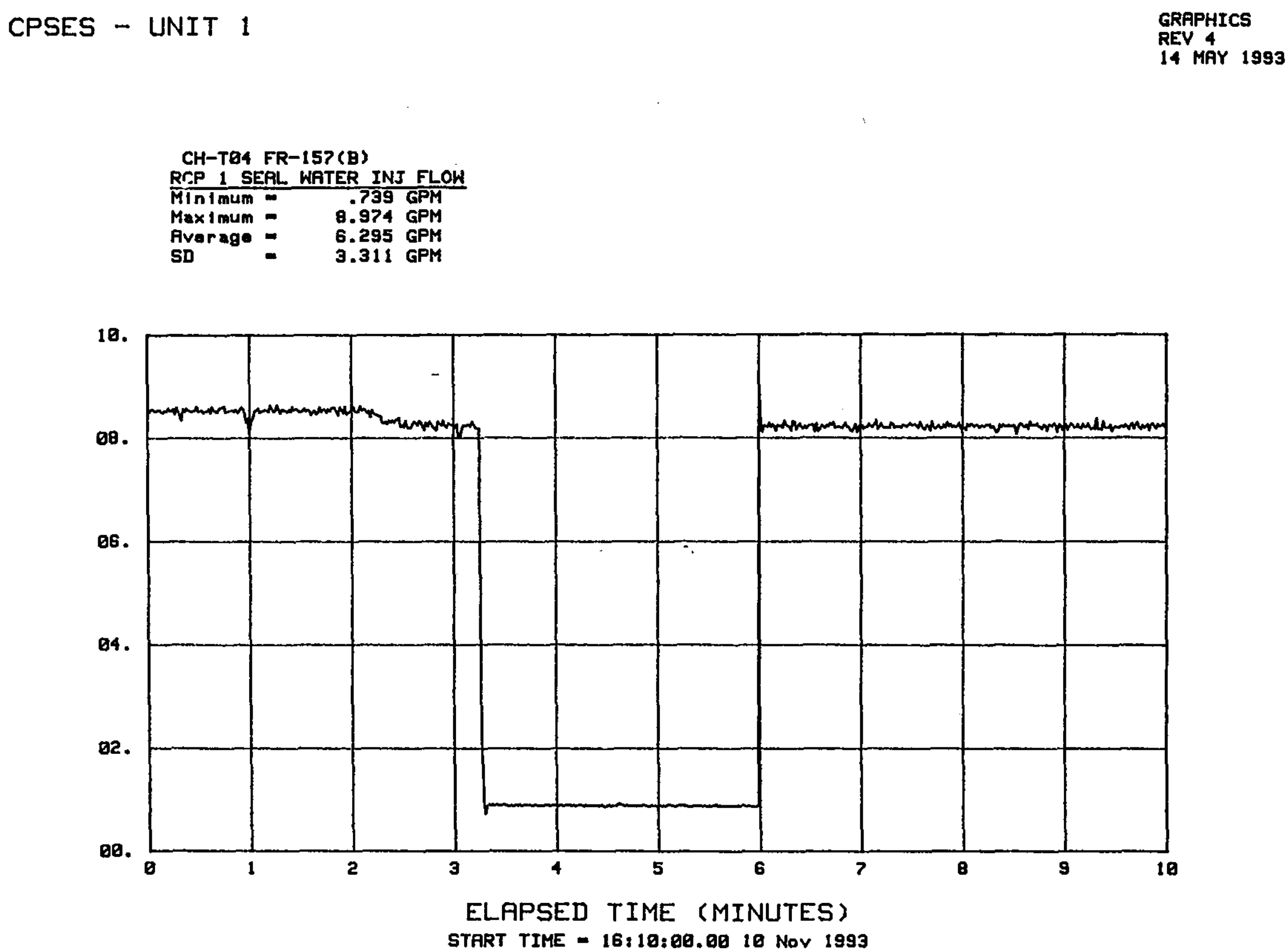


Figure 2. Plant computer data associated with AE test illustrated in Figure 1.

Relationship of Equipment Setup and Data Handling to Achievement of AE Test Goals

Expression of the desired characteristics in the final AE data product depends on proper test equipment settings (gain, voltage), appropriate data filtering, and an acceptable test event.

Typically, two accelerometers (B&W, 1993) per valve are used: one on the bonnet, one on the pipe or valve in the seat area. One channel (accelerometer input to recorder) is set to capture the closure impacting without overrange. The other is "sacrificed" (overrange allowed) in order to demonstrate flow change, with adequate resolution on after-closure levels, and change in steady-state impact levels. The equipment settings selected to avoid overrange are specific for the test, valve and application; settings on sacrificed channels are typically a gain of 8 or higher (on the power supply) and ± 2 volts (recorder input).

Basically, the AE data are conditioned after collection (anti-aliasing filtration during data acquisition) with high-pass and low-pass filters. The cut-off frequency of the low-pass filter should typically be less than 75 Hz, based on frequency domain analysis of close/open event data collected at CPSES to date (Figure 3). The cut-off frequency of the high-pass filter should be selected to capture the multiple natural frequencies of the valve assembly (body plus internals). Based on CPSES data, these appear to fall between 4.5 and 6.5 kHz for the piston check valve models cited in Table 1 (Figure 4). (Note that the exact value varies to a degree among valves of a given model.) The high-pass data are subsequently full-wave rectified. A band-pass filter could be used; however, consistent treatment is important among the valves used for comparisons or trending.

These equipment setup and filtering recommendations are combined to create the following data products. Each trace or trace comparison is used to satisfy one of the former closure verification attributes (corresponding to the former numbering):

1. High-pass envelope of either channel compared with the raw data trace of the sacrificed channel (Figure 1B)
2. High-pass envelope of sacrificed channel (Figure 1A)
3. Low-pass data of the nonoverranged channel (Figure 1C).

For valves on which data from supportive techniques (e.g., magnetic flux or pressure) are being collected simultaneously with the AE data, one of the AE accelerometers is often omitted.

Test Procedure Development

The test procedure must provide AE data with the preceding characteristics. To accomplish this, and do so repeatedly, the test procedure should include the following items:

- Acceptable range of flow through the valve, before the closure event (flow should be >Qmin, if possible) (Figure 5, Item A)
- Limitation of potential noise interference (Figure 5, Item B)
- Step to record the time of the event (alternatively, could synchronize recorder clock with Control Room and, after the event, obtain plant data showing the time of the event; Figure 2)
- Refined actuation source—the source can overcome a less-than-desirable differential pressure (dP) across the closed valve [e.g., cycle of an upstream motor-operated valve (MOV) may provide a better AE test than that of a particular downstream MOV; ideally, this would be discovered during previous non-IST test events] (Figure 5, Item C).

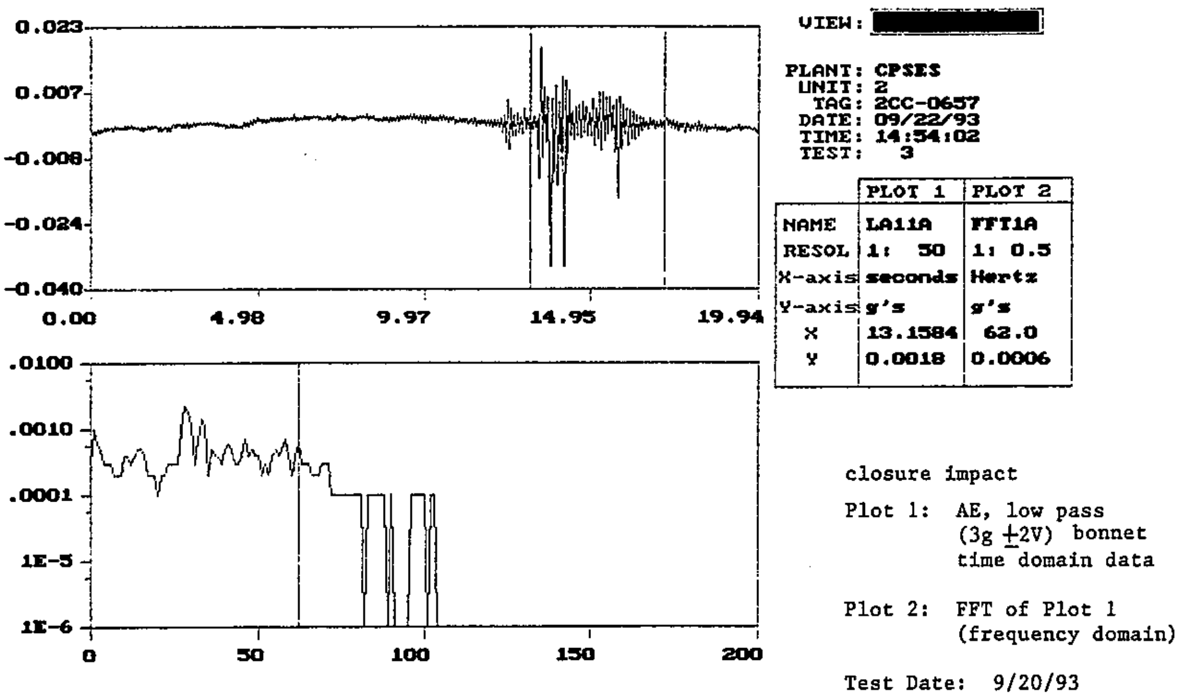


Figure 3A. Low pass frequency domain data from closure verification AE testing of piston check valves illustrating the recommendation for a cut-off frequency less than 75 Hz—Example 1, 2CC-0657.

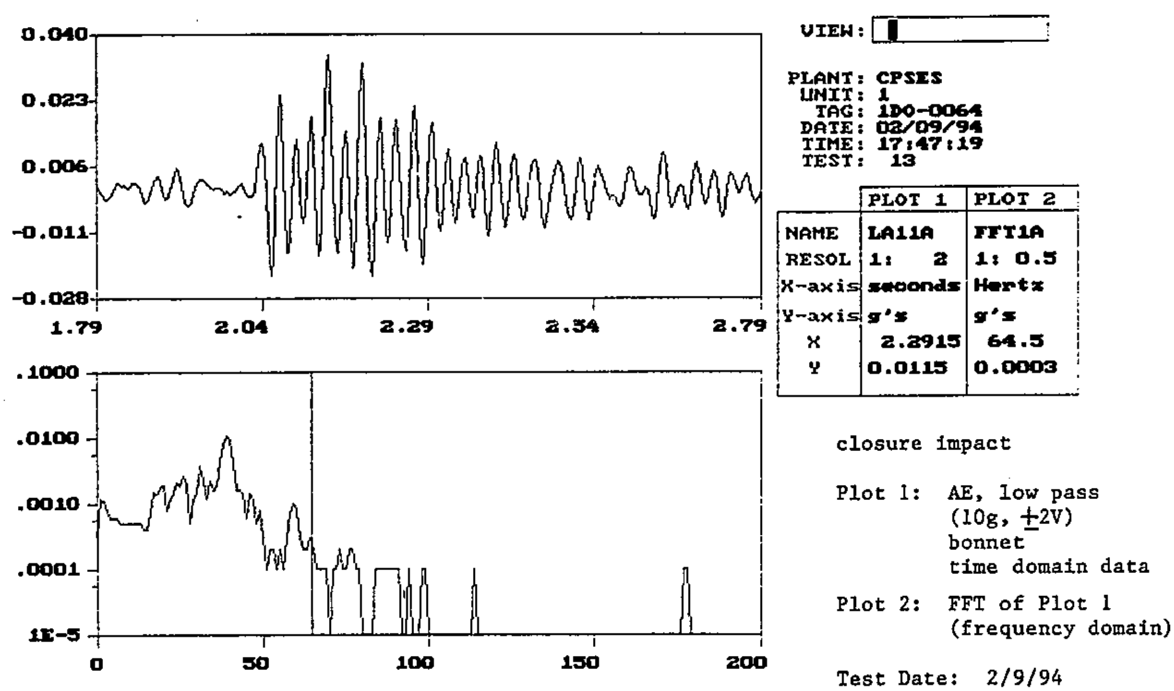


Figure 3B. Low pass frequency domain data from closure verification AE testing of piston check valves illustrating the recommendation for a cut-off frequency less than 75 Hz—Example 2, 1DO-0064.

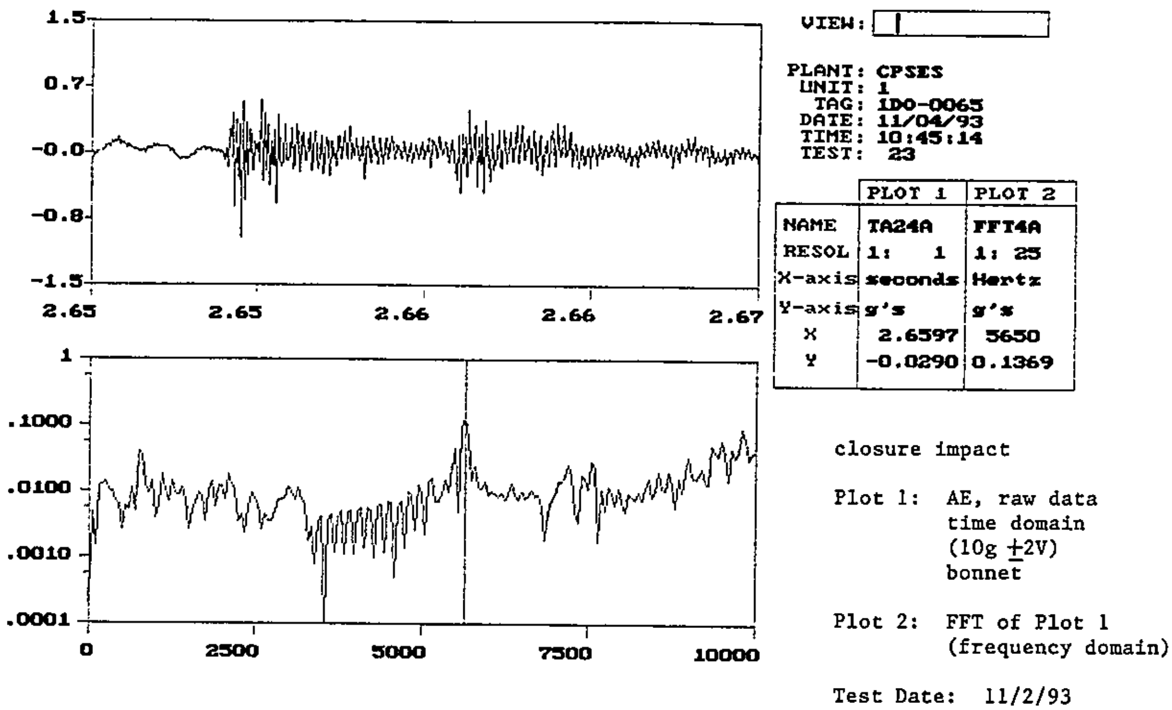


Figure 4A. Frequency domain data from closure verification AE testing of piston check valves illustrating recommendation for a high pass cut-off frequency of less than or equal to 4 kHz—Example 1, 1DO-0065 (first of two check valves), Model 1-1/2-in. 838YT1.

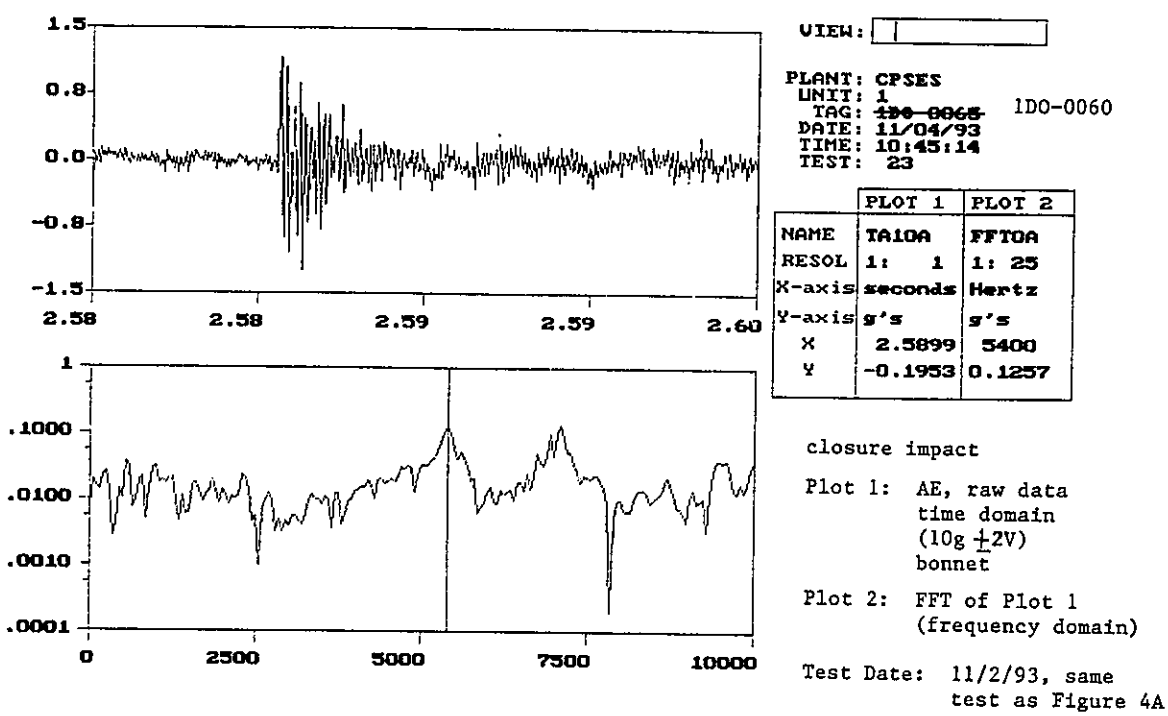
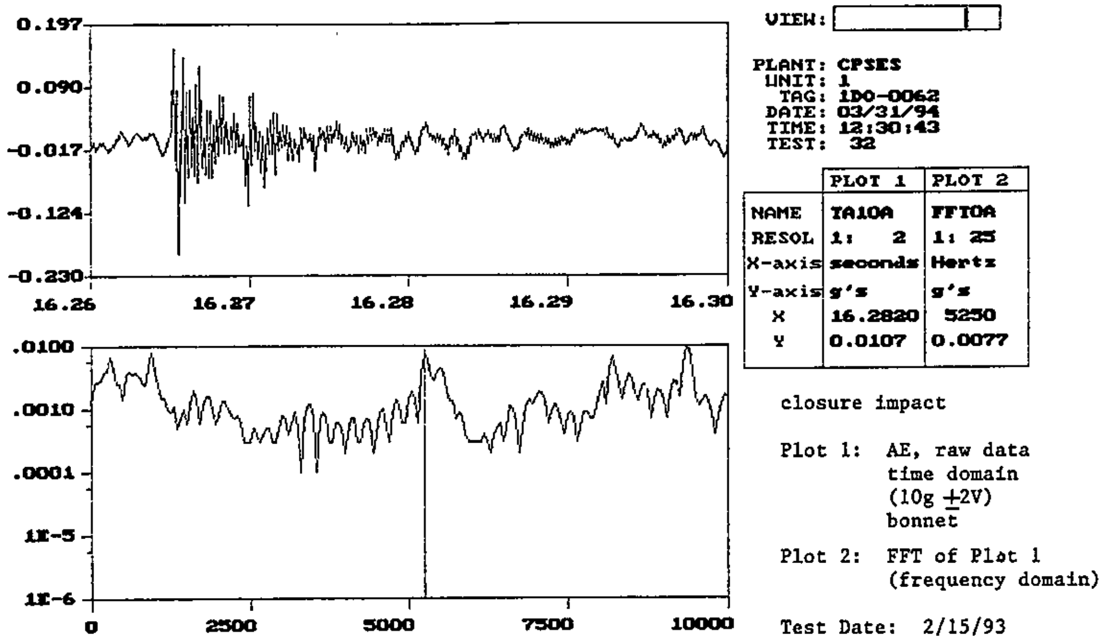


Figure 4B. Frequency domain data from closure verification AE testing of piston check valves illustrating recommendation for a high pass cut-off frequency of less than or equal to 4 kHz—Example 2, 1DO-0060 (second of two), Model 1-1/2-in. 838YT1.



(1) f_n calculated with one end free (in air). With both ends fixed, f_n should be higher. (Personal communication from D. Therneau, Edwards Valve Co., to D. L. Stewart, TU, concerning the natural frequency of selected Edwards valve models, March 29, 1994.)

f_n bending between 2187 and 2011 Hz (1)

f_n torsion between 2435 and 2973 (1)

Figure 4C. Frequency domain data from closure verification AE testing of piston check valves illustrating recommendation for a high pass cut-off frequency of less than or equal to 4 kHz—Example 3, 1DO-0062 (first in series), Edwards Model 1-1/2-in. 838YT1.

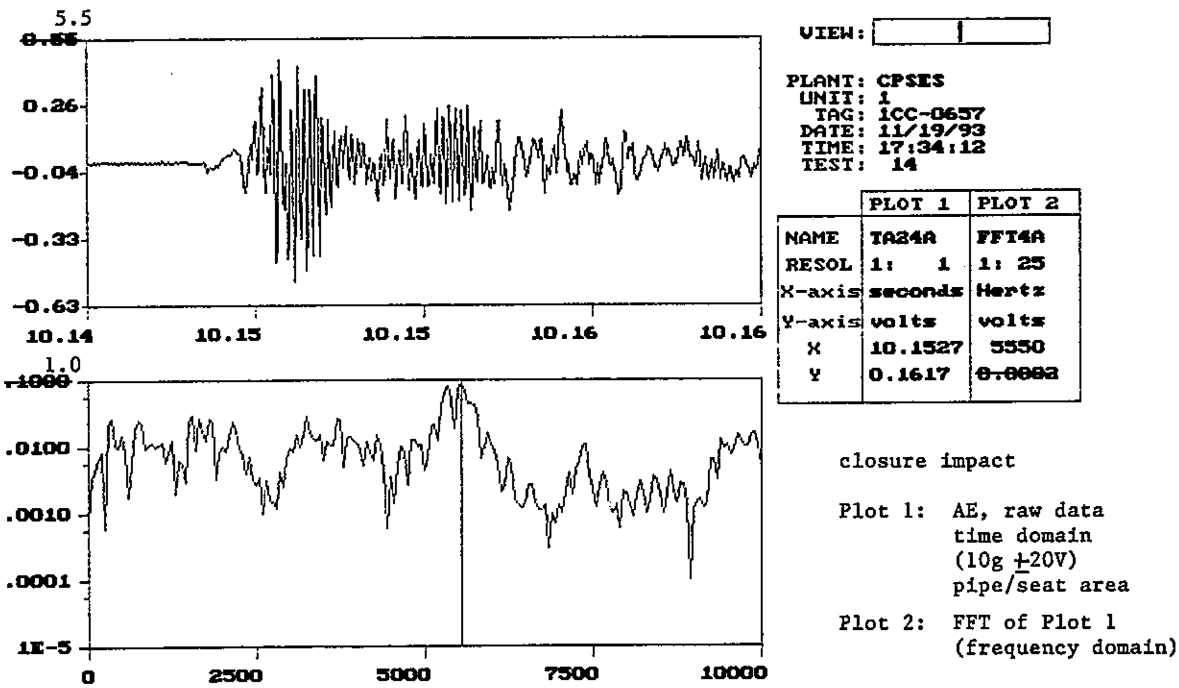
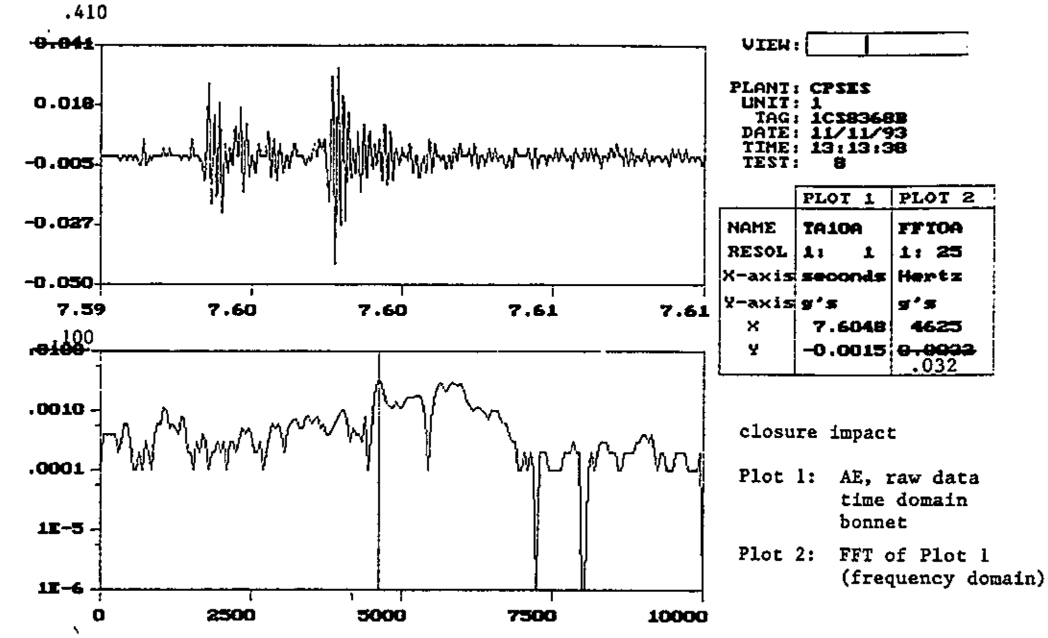


Figure 4D. Frequency domain data from closure verification AE testing of piston check valves illustrating recommendation for a high pass cut-off frequency of less than or equal to 4 kHz—Example 4, 1CC-0657 (first in series), Edwards Model 2-in. 36164.



(1) f_n calculated with one end free (in air). With both ends fixed, f_n should be higher. However, in-liquid f_n is expected to be 14% less than the in-air value. (USNRC, 1988 and personal communication from D. Therneau, Edwards Valve Co., to D. L. Stewart, TU, concerning the natural frequency of selected Edwards valve models, March 29, 1994.)

f_n bending = 1342 Hz (1)

f_n torsion = 3334 Hz (1)

Figure 4E. Frequency domain data from closure verification AE testing of piston check valves illustrating recommendation for a high pass cut-off frequency of less than or equal to 4 kHz—Example 5, 1CS-8368B (first in series), Edwards Model 2-in. 3674.

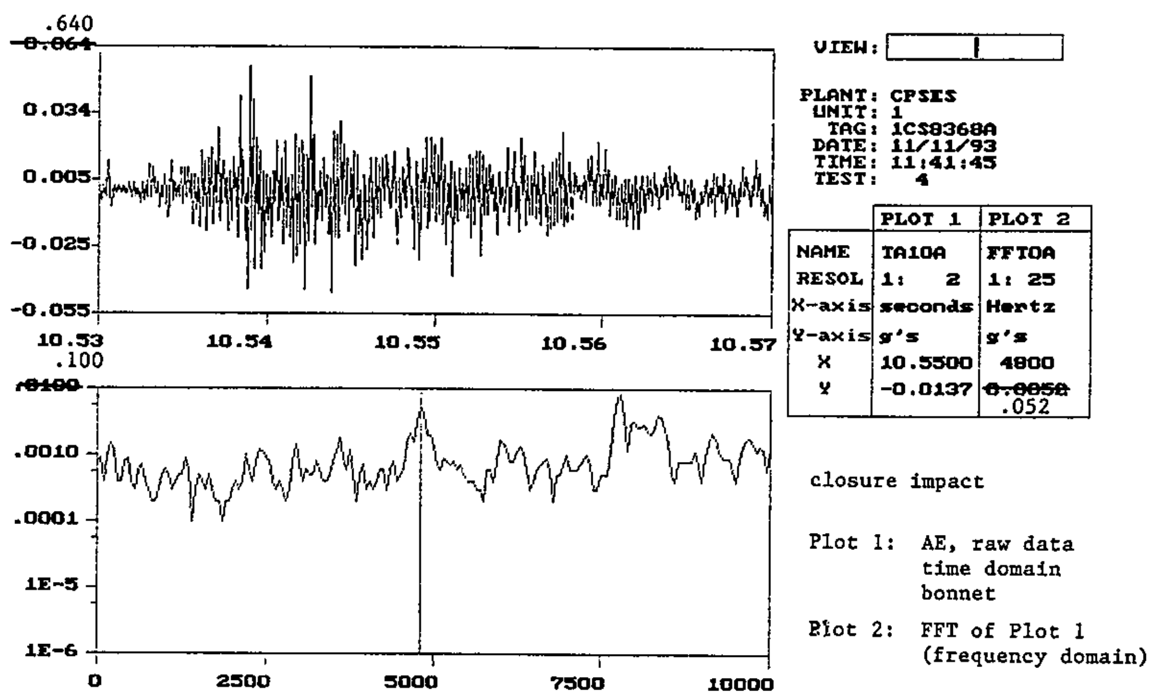


Figure 4F. Frequency domain data from closure verification AE testing of piston check valves illustrating recommendation for a high pass cut-off frequency of less than or equal to 4 kHz—Example 6, 1CS-8368A (first in series), Edwards Model 2-in. 3674 (compare with Figure 4E).

CPSES OPERATIONS TESTING MANUAL	UNIT 1	PROCEDURE NO. OPT-520A
CVCS CHECK VALVES	REVISION NO. 1	PAGE 9 OF 16

8.0 INSTRUCTIONS

8.1 RCP Seal Injection Check Valve Test

> NOTE: Record all data on Form OPT-520A-1.

☐ 8.1.1 Ensure QC OR applicable test group has test equipment installed for the check valves to be tested.

8.1.2 Verify one of the following conditions exist for stopping RCP seal injection flow, OR perform Step 8.1.3:

- ☐ • Reactor Coolant system is in Mid Loop operations. (RCS water level below RCP seals)
- ☐ • RCP seals are on the backseat.

8.1.3 IF conditions in Step 8.1.2 can NOT be verified, THEN perform the following in preparation of securing seal injection flow to the RCPs:

☐ A. Verify RCS pressure is <200 psig.

B. Ensure the seal leakoff valves are closed:

- ☐ • 1/1-8141A, RCP 1 SEAL LKOFF VLV
- ☐ • 1/1-8141B, RCP 2 SEAL LKOFF VLV
- ☐ • 1/1-8141C, RCP 3 SEAL LKOFF VLV
- ☐ • 1/1-8141D, RCP 4 SEAL LKOFF VLV

☐ 8.1.4 Ensure a charging pump is in operation.

> NOTE: Max of 10 gpm is used in the next step to prevent exceeding 13 gpm when seal injection is secured to a pump. Flow may have to be reduced more as seal injection is secured to each pump.

☐ 8.1.5 Ensure seal injection is adjusted between 6 to 10 gpm to each RCP. As each seal injection line is tested, seal injection flow on the other inservice seal injection lines will increase. Seal injection flow should be monitored during the test and throttled such that isolating a seal injection line will NOT result in any RCP seal injection line exceeding 13 gpm.

CPSES OPERATIONS TESTING MANUAL	UNIT 1	PROCEDURE NO. OPT-520A
CVCS CHECK VALVES	REVISION NO. 1	PAGE 10 OF 16

8.1.6 Verify test personnel are standing by to collect test data for the following check valves:

- ☐ • 1CS-8350A
- ☐ • 1CS-8367A
- ☐ • 1CS-8368A

C

☐ 8.1.7 Close 1/1-8351A, RCP 1 SEAL WTR INJ VLV, AND verify test personnel obtained the required data.

8.1.8 Verify test personnel are standing by to collect test data for the following check valves:

- ☐ • 1CS-8350B
- ☐ • 1CS-8367B
- ☐ • 1CS-8368B

☐ 8.1.9 Close 1/1-8351B, RCP 2 SEAL WTR INJ VLV, AND verify test personnel obtained the required data.

8.1.10 Verify test personnel are standing by to collect test data for the following check valves:

- ☐ • 1CS-8350C
- ☐ • 1CS-8367C
- ☐ • 1CS-8368C

☐ 8.1.11 Close 1/1-8351C, RCP 3 SEAL WTR INJ VLV, AND verify test personnel obtained the required data.

8.1.12 Verify test personnel are standing by to collect test data for the following check valves:

- ☐ • 1CS-8350D
- ☐ • 1CS-8367D
- ☐ • 1CS-8368D

☐ 8.1.13 Close 1/1-8351D, RCP 4 SEAL WTR INJ VLV, AND verify test personnel obtain the required data.

Figure 5. Test procedure incorporating three key items needed for a successful, repeatable IST closure verification AE test.

CPSES OPERATIONS TESTING MANUAL	UNIT 1	PROCEDURE NO. OPT-520A
CVCS CHECK VALVES	REVISION NO. 1	PAGE 7 OF 16

6.2 The following prerequisites apply to Section 8.2 and 8.3:

- ☐ • Form OPT-520A-2 or OPT-520A-3, as applicable, is available.
- ☐ • Unit 1 is NOT in water solid operations.
- ☐ • RCS temperature is ≤ 150°F.
- ☐ • Unit 1 is in MODE 5 or 6.
- ☐ • No RCPs are running. B
- • Notify QC or applicable test group to install applicable test equipment for check valve testing for the check valves being tested:

Section 8.2

Loop 1 Charging Line

- ☐ 1-8379A/B
- ☐ 1CS-8377 (N/A if NOT required)
- ☐ 1-8381 (N/A if NOT required)

Section 8.3

Loop 4 Charging Line

- ☐ 1-8378A/B
- ☐ 1CS-8377 (N/A if NOT required)
- ☐ 1-8381 (N/A if NOT required)

CPSES OPERATIONS TESTING MANUAL	UNIT 1	PROCEDURE NO. OPT-520A
CVCS CHECK VALVES	REVISION NO. 1	PAGE 8 OF 16

6.2 (continued)

CAUTION:	Seal injection to the RCPs shall be secured to prevent pressure spikes on RCP seals during performance of Section 8.2 OR 8.3. Procedure guidance is provided in the procedure for securing seal injection, if required.

- • IF NO charging pumps are in service THEN ensure the following valves are closed:
  - ☐ 1/1-8351A, RCP 1 SEAL WTR INJ VLV
  - ☐ 1/1-8351B, RCP 2 SEAL WTR INJ VLV
  - ☐ 1/1-8351C, RCP 3 SEAL WTR INJ VLV
  - ☐ 1/1-8351D, RCP 4 SEAL WTR INJ VLV
- ☐ • A charging pump will be required to supply charging flow of 75 to 85 gpm. A As required by plant conditions, the charging pump may be started just prior to starting the test.
- ☐ • Due to the varied plant conditions that may exist during MODE 5 or 6, ensure this test will NOT adversely affect any other equipment, test or plant requirements.
- ☐ • CVCS transients are being tracked for the life of the plant by Engineering. Collect data for the parameters required by STA-706, as required, during performance of this test.

7.0 TEST EQUIPMENT

None

Figure 5. (continued).

In-Series Check Valves

Fifty-six of our CVRP piston check valves (28 of the 37 per unit) are "in-series" check valves; all have been successfully AE tested, with multiple test data available for each.

Typically, the second check valve of an in-series pair has proven the most challenging to evaluate of the two. Although a defined closure impact would be expected, it could be associated with a minor-to-negligible flow change (even at a gain above 8, ± 2V).

The steady-state impact levels should still change, but there may or may not be evidence (via low-pass filtering) of movement in the internals during closure. The evaluation effort centers on separating the closure impacts originating in the second valve from those in the first.

Because the data sampling rate achieved during data conditioning (filtering) may prevent the use of the "time-of-arrival" technique, a comparison of signal magnitudes (signal attentuation) between valves during the same closure event has often been used (Figure 6).

The magnetic flux technology, both ac and dc, has been helpful on the second valves (Figure 7). Basically, a position change is substituted for a notable flow change or used to support a less-than-definitive impact associated with the valve.

However, note that the technique is still considered research grade; proper equipment setup appears to be crucial for this technique. (Figure 8 illustrates the only dc magnetic flux setup with which we have successfully and repeatedly obtained data on piston check valves.)

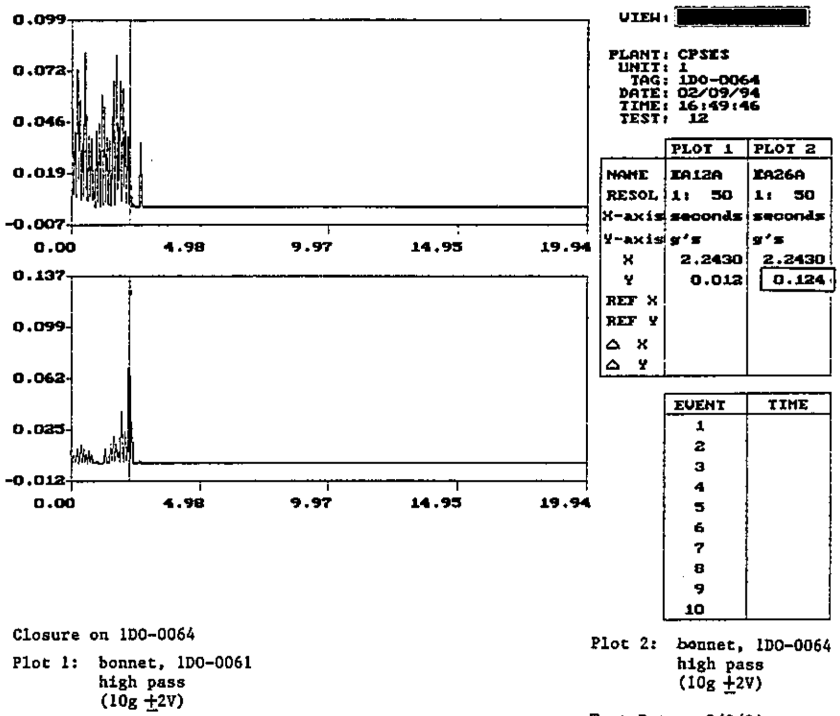


Figure 6A. Determination of impact source using signal magnitude comparison—closure verification on in-series check valve 1DO-0064 (both valves simultaneously tested and taped on same data recorder, during compressor shutdown).

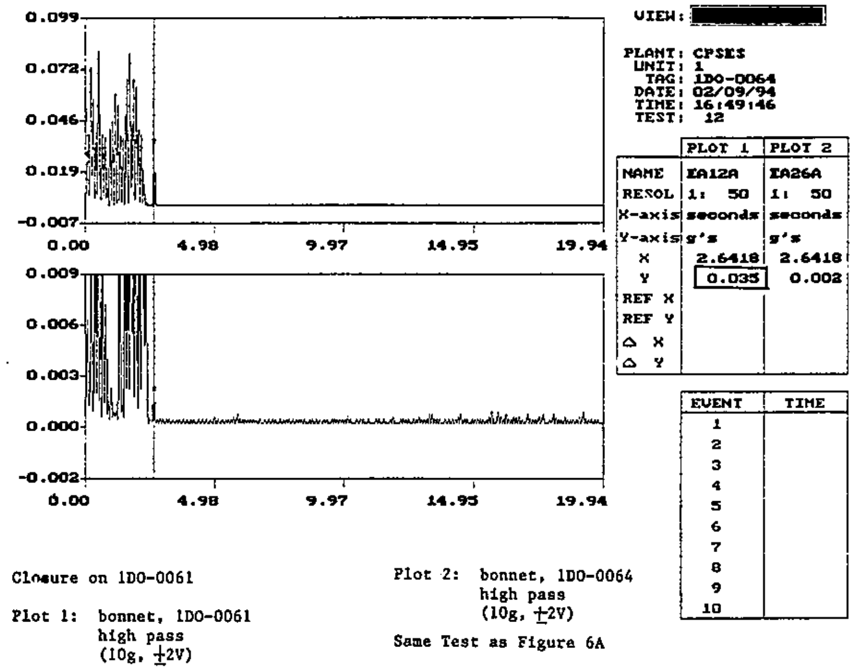


Figure 6B. Determination of impact source using signal magnitude comparison—closure verification on in-series check valve 1DO-0064 (same test event as Figure 6A).

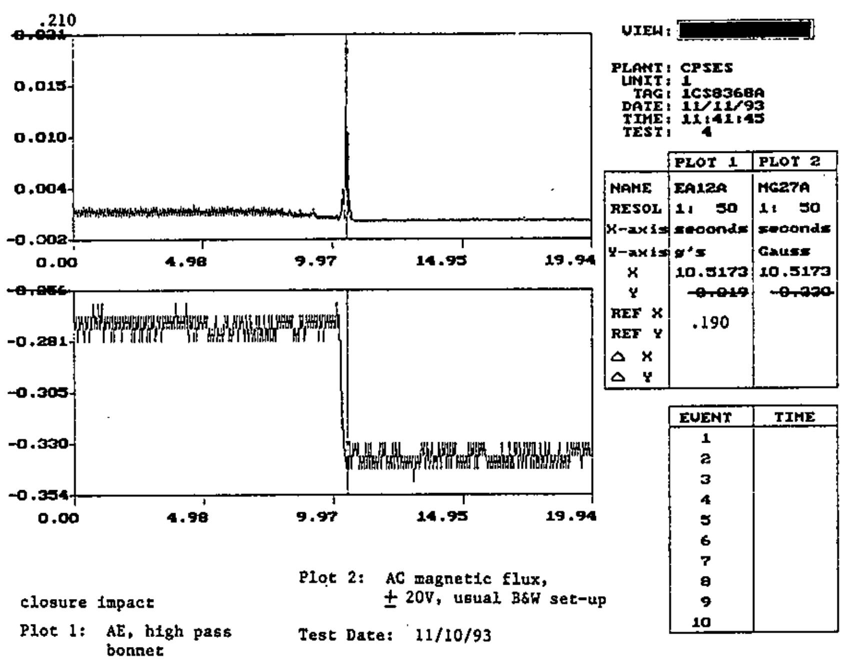


Figure 7. AC magnetic flux data collected on a piston check valve—closure verification on 1CS-8368A (first in a series of three).

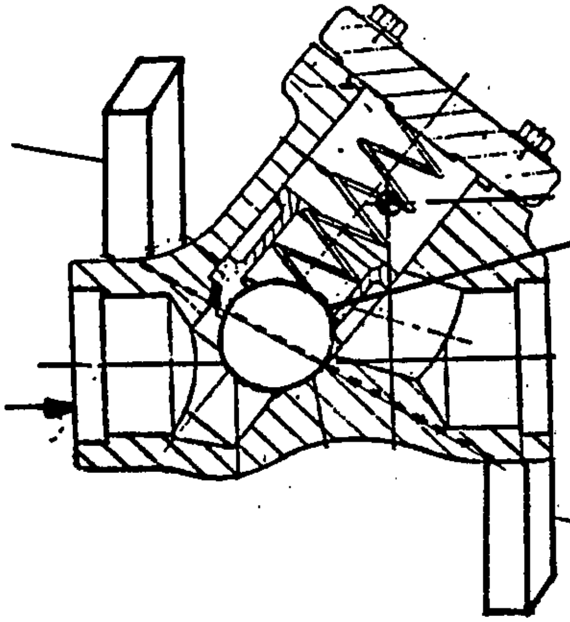


Figure 8. DC magnetic flux setup on a piston check valve. (Note: Broad side of magnet is facing valve body and both magnets are located on the body; hall effect probe is located along a line between the two magnets, in the seat area.)

Adverse Data

The system effect on check valve closure cannot be overlooked; it can at times cause a valve to seat poorly, without degradation present in the valve. Because such a condition could be sporadic in nature, it is wise to retest any valve that fails to meet the recommended closure verification attributes before deciding to disassemble the valve. (Figures 9A and 9B represent adverse data; Figure 10 shows retest data following a disassembly in which the internals were acceptable without refurbishment.)

CONDITION MONITORING

In order to assess the condition of a piston check valve properly, a nonintrusive technique must go beyond closure verification testing. The technique must be able to diagnose, at least conservatively, the degradations or adverse conditions that are considered of major concern for this type of valve.

Although it provided significantly useful data on swing check valve diagnosis, the Nuclear Industry Check Valve Group (NIC) test effort has provided little useful data on the detection of degradation in piston check valves. (Maffa and Kahley, 1993) No lift check was included in the extensive Phase 1 (liquid) testing, and, although two types of lift check valves (neither manufactured by Edwards) were included in Phase 2 (Air) testing, no actual nonintrusive data were published (USUF, 1993). Therefore, we have had to rely largely on the results from our own test effort when diagnosing piston check valves.

Scope of the AE Data Evaluation Matrix

Upon review of applicable Nuclear Plant Reliability Data System (NPRDS) data (Table 3), we determined that three conditions were of major concern in our reliability monitoring efforts on piston check valves: stuck partially/full open plug, seat wear (disc or valve seat), and plug wear (as a precursor to the other two concerns).

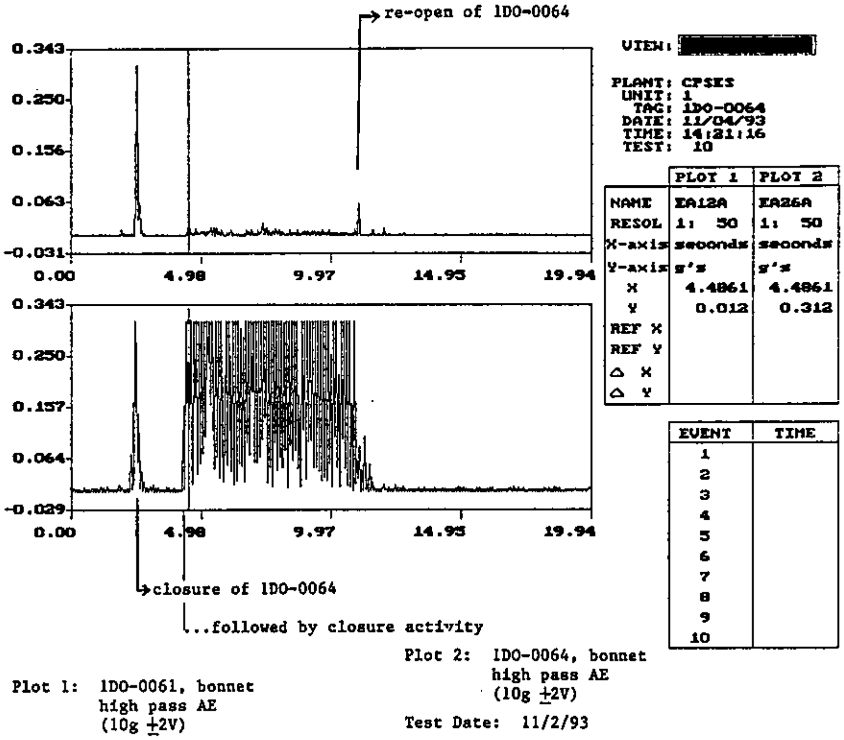


Figure 9A. Before disassembly AE data on 1DO-0064—high pass comparison between in-series valves 1DO-0061 and 1DO-0064 (data were collected during an air dryer transient).

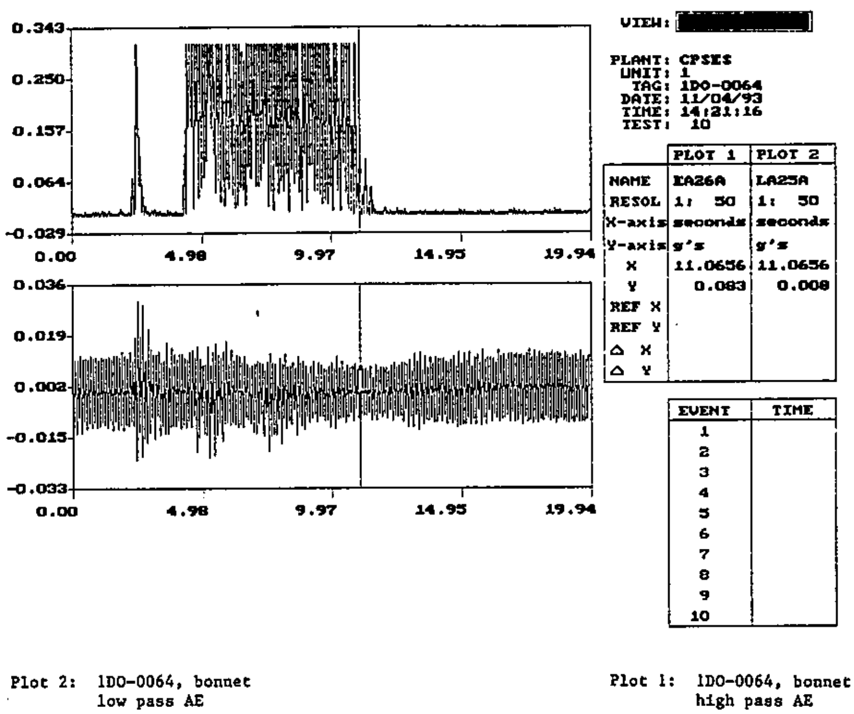


Figure 9B. Before disassembly AE data on 1DO-0061—high pass to low pass data comparison on 1DO-0064 (same test event as Figure 9A).

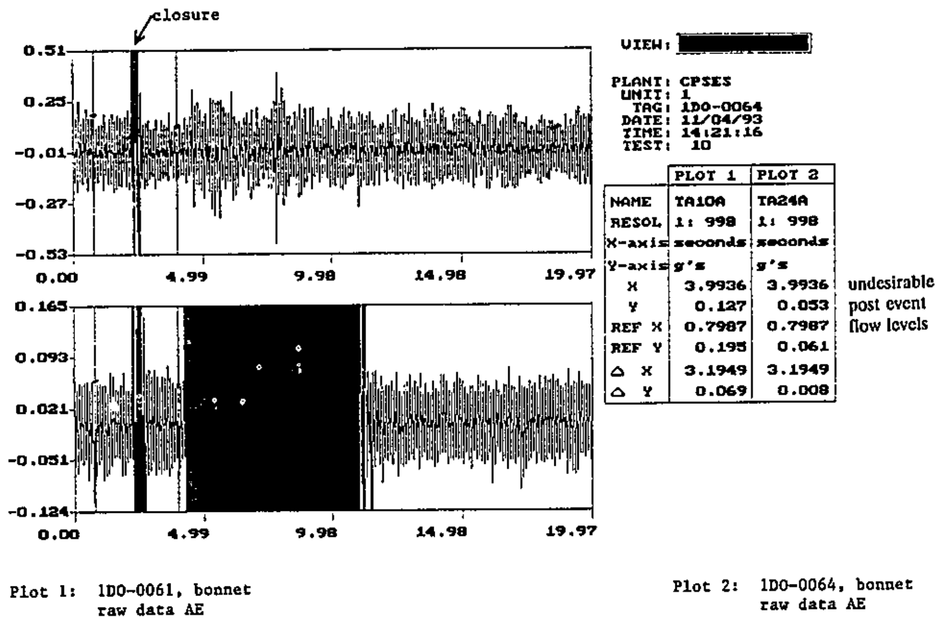


Figure 9C. Before disassembly AE data on 1DO-0064d—raw data comparison between 1DO-0061 and 1DO-0064 (same test event as Figures 9A and B).

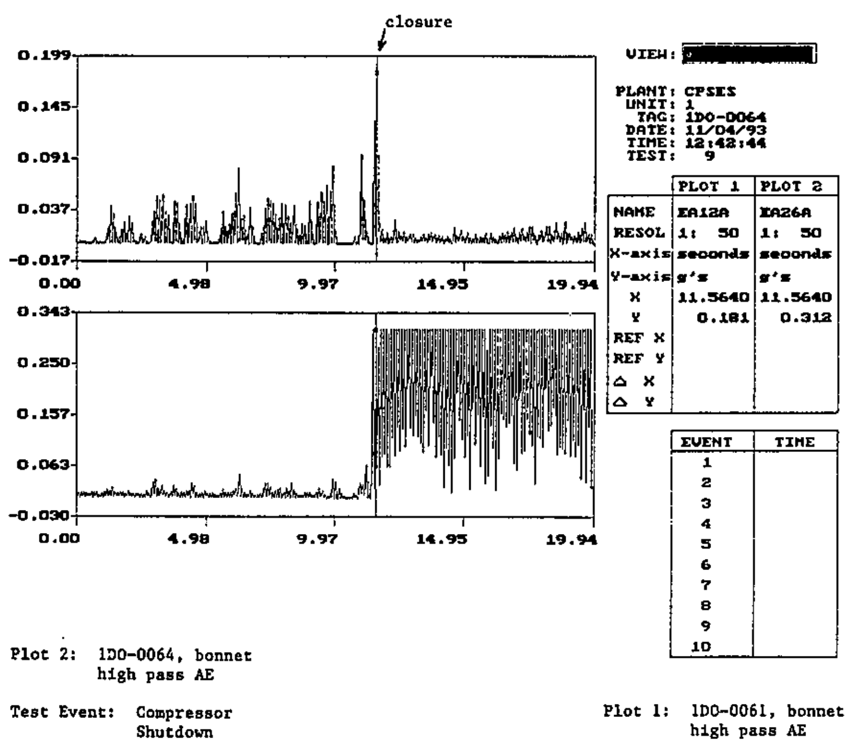


Figure 9D. Before disassembly AE data on 1DO-0064—high pass data comparison between 1DO-0061 and 1DO-0064 [data were collected during compressor shutdown on same test date (and at same equipment settings) as Figure 9A through C].

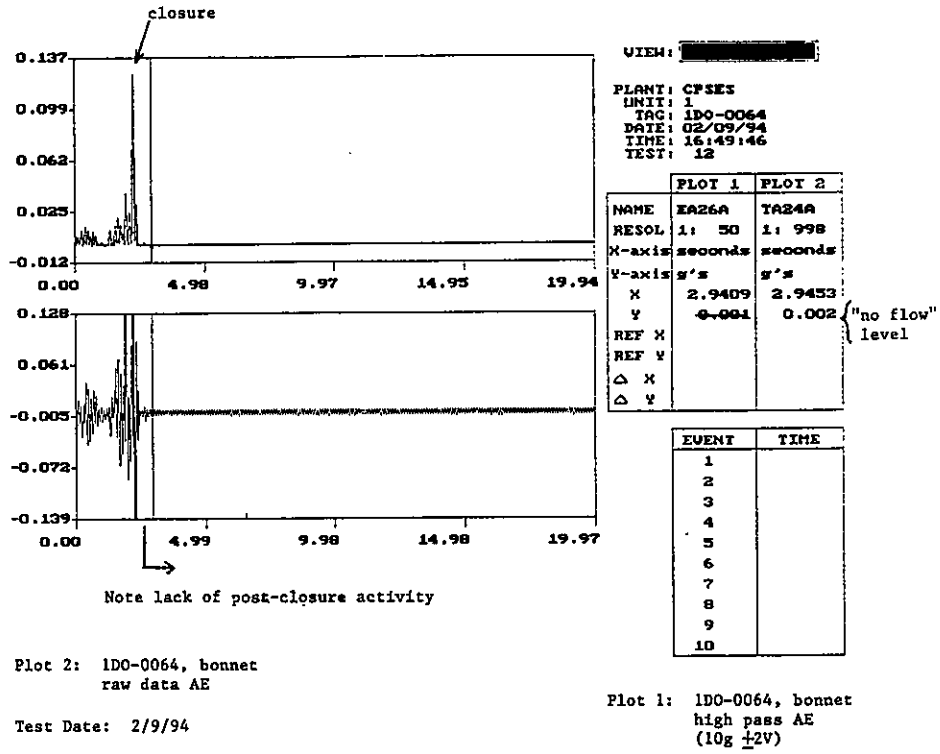


Figure 10. After disassembly AE data on 1DO-0064—high pass to raw data comparison on 1DO-0064 (data were collected during compressor shutdown).

Extending of the closure verification attributes presented previously based on site and industry experience, an AE data evaluation matrix for piston check valves was developed (Figure 11) to diagnose these three conditions. Two conditions were not included: stuck fully closed plug and broken spring. A stuck fully closed plug was omitted from the matrix, even though it would be detectable during closure verification testing (no closure impact; uncharacteristic flow level prior to closure event). Because AE tests are performed during a functional flow test, the total blockage presented by the check valve should be apparent to operations personnel during the AE test. Therefore, analysis of the AE data for this condition would be redundant. Note that even the low frequency of occurrence (NPRDS) might justify its exclusion from the matrix.

A broken spring was not included in the matrix because there is no evidence (NPRDS) that a broken spring has caused a valve failure (either through interference of loose parts in valve operation or through lack of the spring's contribution to valve function). For many applications,[c] the spring is an optional part of the valve assembly.

Development of the AE Data Evaluation Matrix

Each check valve diagnosis at CPSES is currently performed with time domain data. Industry studies in frequency domain data analysis, to date, have provided limited confidence in its use for determining check valve degradation (Moffa and Kahley, 1993). The following evidence to support the development of the AE data evaluation matrix is based largely on CPSES data.

Stuck Partially/Full Open Plug. The matrix input was derived from testing experience with swing check valves. No stuck open/partially open piston check valves have been detected in any of our test population since AE data were initially collected.

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c. Edwards Valves, Inc., *Valve Catalog and Application Manual*, 2nd Edition, pp. G11 and G14.

Table 3. NPRDS summary of Edwards check valves with failures after April 1, 1985, manually sorted for piston check models and failure description.[a]

Condition	Number of failures	Representing number of plants
Normal/abnormal wear/damage of disc and valve body seating surfaces (typically failed LLRTs)	60	29
Stuck open or failed to close (vast majority cite particulate contamination or corrosion)	95	33
Plug wear, other than seat: Guides (and bore) specific citings	5	3
Included in stuck open total	1	—
Grooves worn in body bore; found during maintenance exam	2	—
Grooves worn in body bore above upper disc guide ring area. Grooves restricted full stroke travel of disc. Utility considered spring removal to reduce internal impact frequency. Found during maintenance exam.	2	—
Spring Problems	2	2
Suspect cause of plug hang-up was slightly distorted spring; replaced spring, cleaned	1	1
During maintenance exam, found spring corroded and broken in four places (no failed test)	1	1
Stuck closed (particulate contamination or corrosion; lack of lubrication)	9	7

a. Rough breakdown of finding based on a data search performed February 6, 1993.

Data were obtained for the clear-way style swing check valve. A similar test event was conducted on a set of like valves, one with the internals removed (startup testing, special test configuration). A valve without internals should model a stuck fully open condition. Graphic differences between tests on this valve and like valves were noted, as shown in Figure 12.

Seat Wear. The matrix input was derived from leak detection experience on a variety of other valve types (atmospheric relief valves, main steam dump valves, non-piston check valves), using CVRP test equipment. Our initial efforts were based on input from Philadelphia Electric.[d] Note that the 2X and 6X limits are rule-of-thumb only, as is the "typical baseline of less than or equal to 0.020 g." Again, comparison among like valves is crucial.

d. Personal communication from J. McElroy (Philadelphia Electric Company) to D. L. Stewart (TU) concerning leakage detection for main steam dump valves, April 10, 1992.

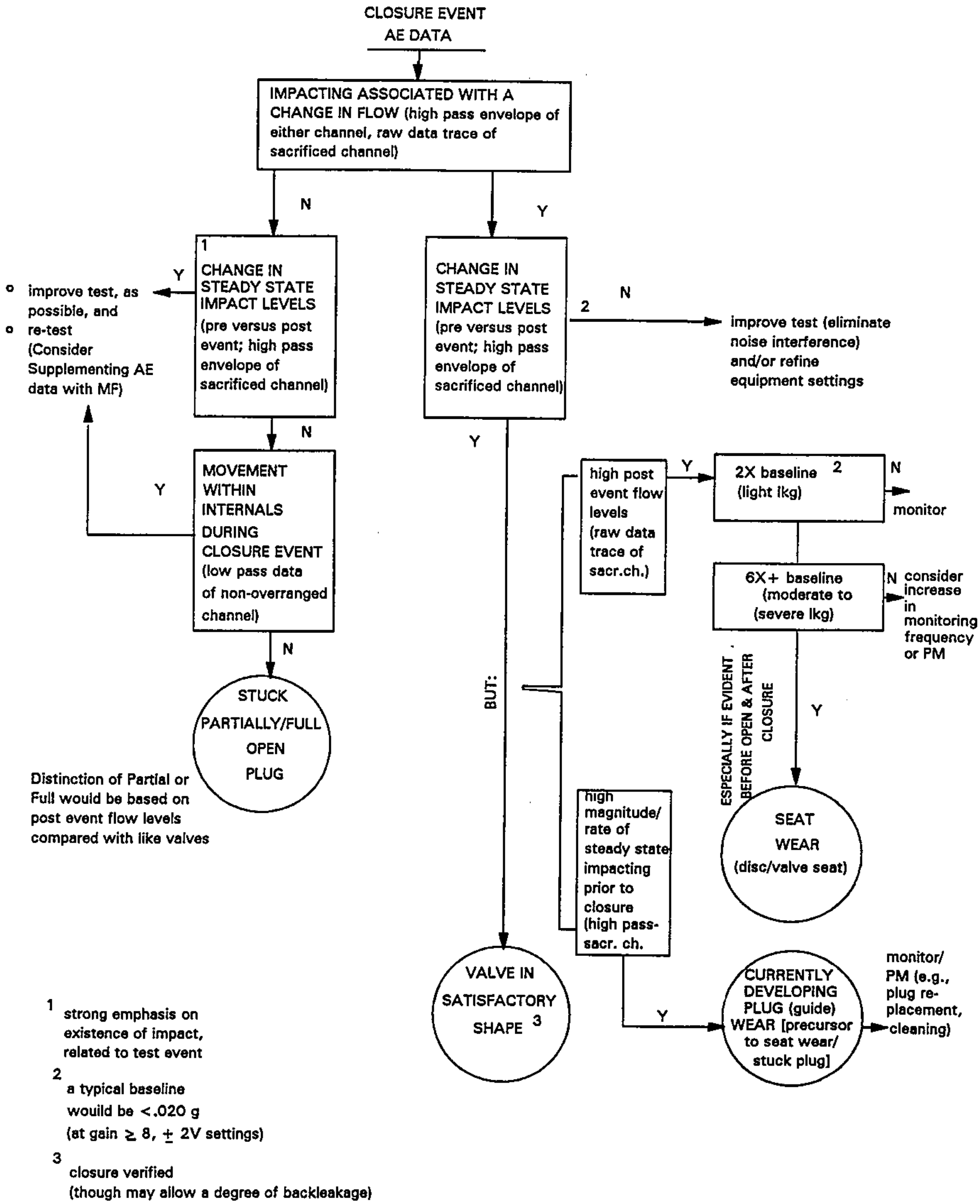


Figure 11. AE data evaluation matrix for piston check valves.

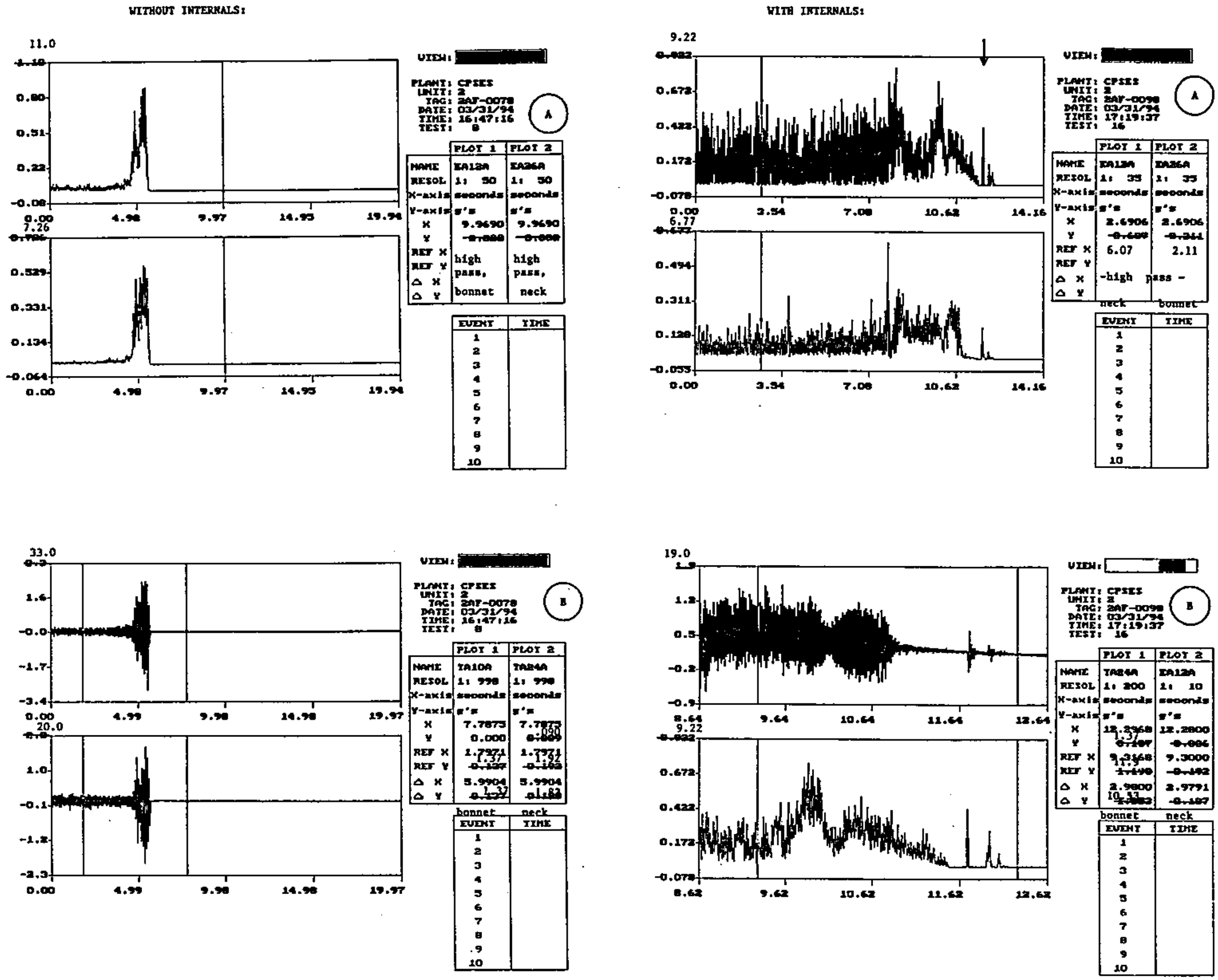
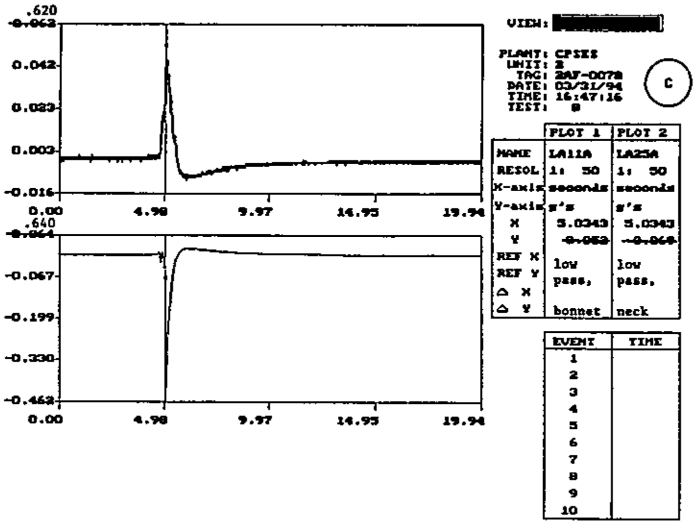
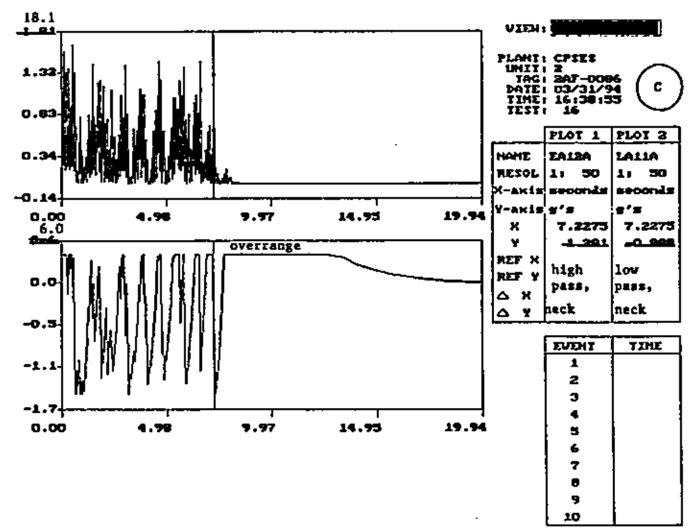


Figure 12. Stuck partially/full open plug—evidence based on clear-way swing check valve data, with versus without internals.





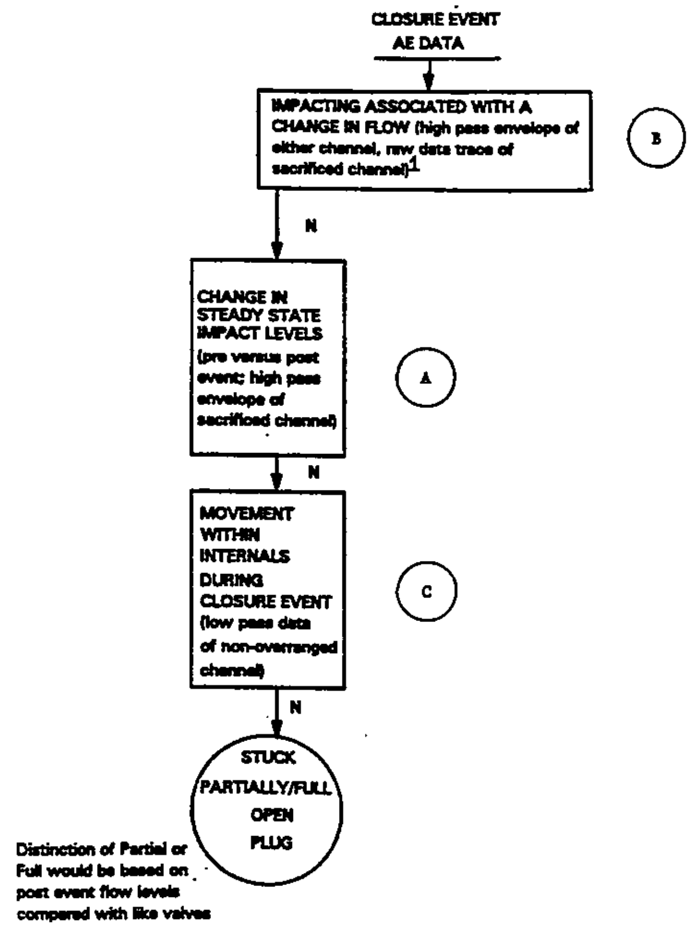


Figure 12. (continued).

Figure 13 shows monitoring of CPSES Unit 1 and 2 atmospheric relief valves over about a 6-month period. Valve 1-PV-2327 was refurbished (steam cutting found on pilot plug and stem assembly); between the September 30, 1993, and January 20, 1994, testing note the pre- and post-AE levels.

Plug (Guide) Wear. Plug (guide) wear is used as a precursor for seat wear or stuck plug. Determination is currently based on steady-state impact magnitude or rate, as compared among like valves. Tests produced very few "true positives" (diagnosis backed by disassembly), but several "false positives," which include very minor plug wear that was well short of the refurbishment point. As a minimum, emphasis must be placed on comparing like valves under like situations (especially valve application, test event).

Disassembly of the reactor coolant pump seal injection check valve (1CS-8368C) during the fall of 1993 (third refueling outage) revealed minor guide wear. Previous AE data, collected during the fall of 1992, showed a notable impact rate, as compared with like valves (e.g., 1CS-8368B). No refurbishment was performed; the plug was reinstalled. AE test data taken after the disassembly (Figure 14) showed a similar rate and magnitude of impacting, as compared with like valves. More data, however, are needed to confirm this "detection."

CONCLUSIONS

The data characteristics necessary for an acceptable AE test were determined and used to develop several successful IST (closure verification) test procedures.

An AE data evaluation matrix for piston check valves was subsequently developed, based on industry experience and the results of 3 years of AE testing (IST and reliability monitoring) at CPSES on a variety of valve types. Further refinement of the matrix, however, is needed (especially concerning the detection of plug wear).

ACKNOWLEDGMENTS

The author acknowledges the contributions of Mike Burch, Controlled Vibrations, Inc., and Tony Moffa, Liberty Technologies, Inc.

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U.S. Nuclear Regulatory Commission, 1988, *Prediction of Check Valve Performance and Degradation in Nuclear Power Plant Systems,* NUREG/CR-5583, April, p. 32.

Utah State University Foundation (USUF), *1993, Evaluation of Nonintrusive Diagnostic Technologies for Check Valves,* NIC-02-AIR, February.

Raw Data from Stack, Near Valve
(Peak, Actual), g

TST DATE	7/29	8/04	8/12	8/25	9/02	9/09	9/30	1/20
1PV2325	.132		.101	.081	.075	.117	.084	.114
1PV2328	.145		.142	.269	.203	.320	.214	.218
1PV2326 (4)	.208		.267	.252	.388	.296	.337	.175
1PV2327 (5)	.277	.301	.290	.281	.277	.262	.316 (1)	.125

TST DATE	8/12	8/25	9/02	9/09	11/25	12/28
2PV2325	.187	.143	.187	.158	.175	.246
2PV2328	.137	---	.173	.156	.269	.233
2PV2326	.130	.182	.160	.230	.244	.688 (2)
2PV2327	.102 (3)	.104	.102	.135	.139	.134

Notes:

(1) Refurbishment following 9/30/93 testing. Note levels during subsequent, 1/20/94, testing.

(2) Visible leakage out stack.

(3) This value used for baseline.

(4) Audible steam cutting within valve.

(5) Efforts to reseat valve and retest (prior to 9/02/93 testing):

Prior to Manual Seat, Unisolated	body	.024
Manually Seated and Isolated	stack body	0.00 .011
Manually Seated, Unisolated (post)	body	.022

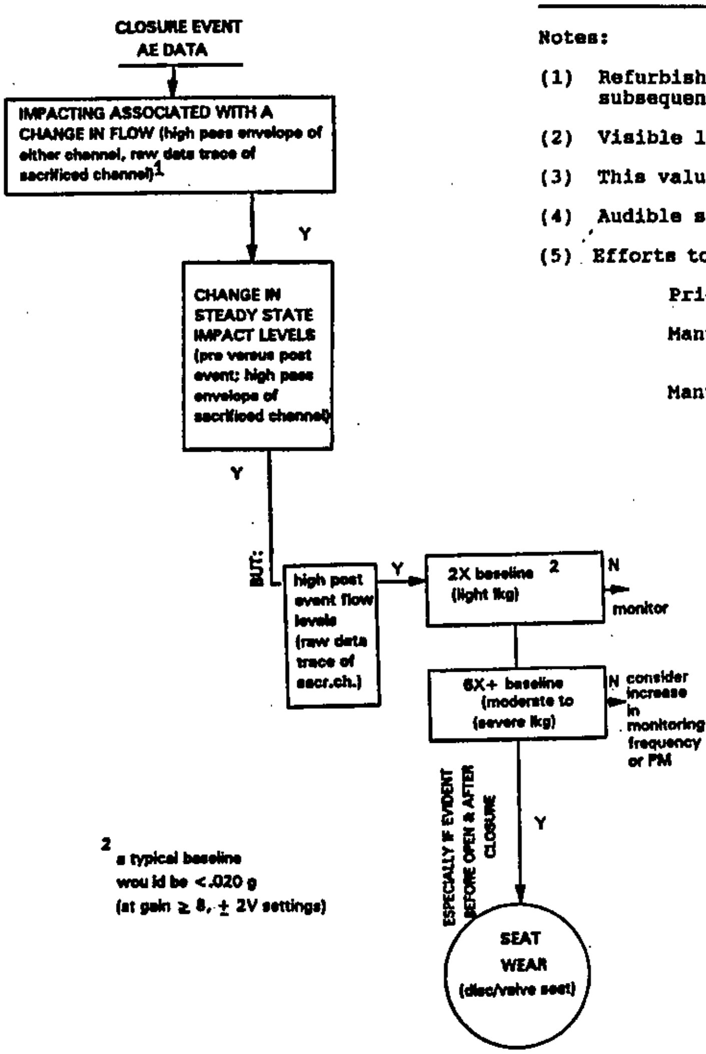

Figure 13. Seat wear—evidence based on leak detection results on Units 1 and 2 atmospheric relief valves.

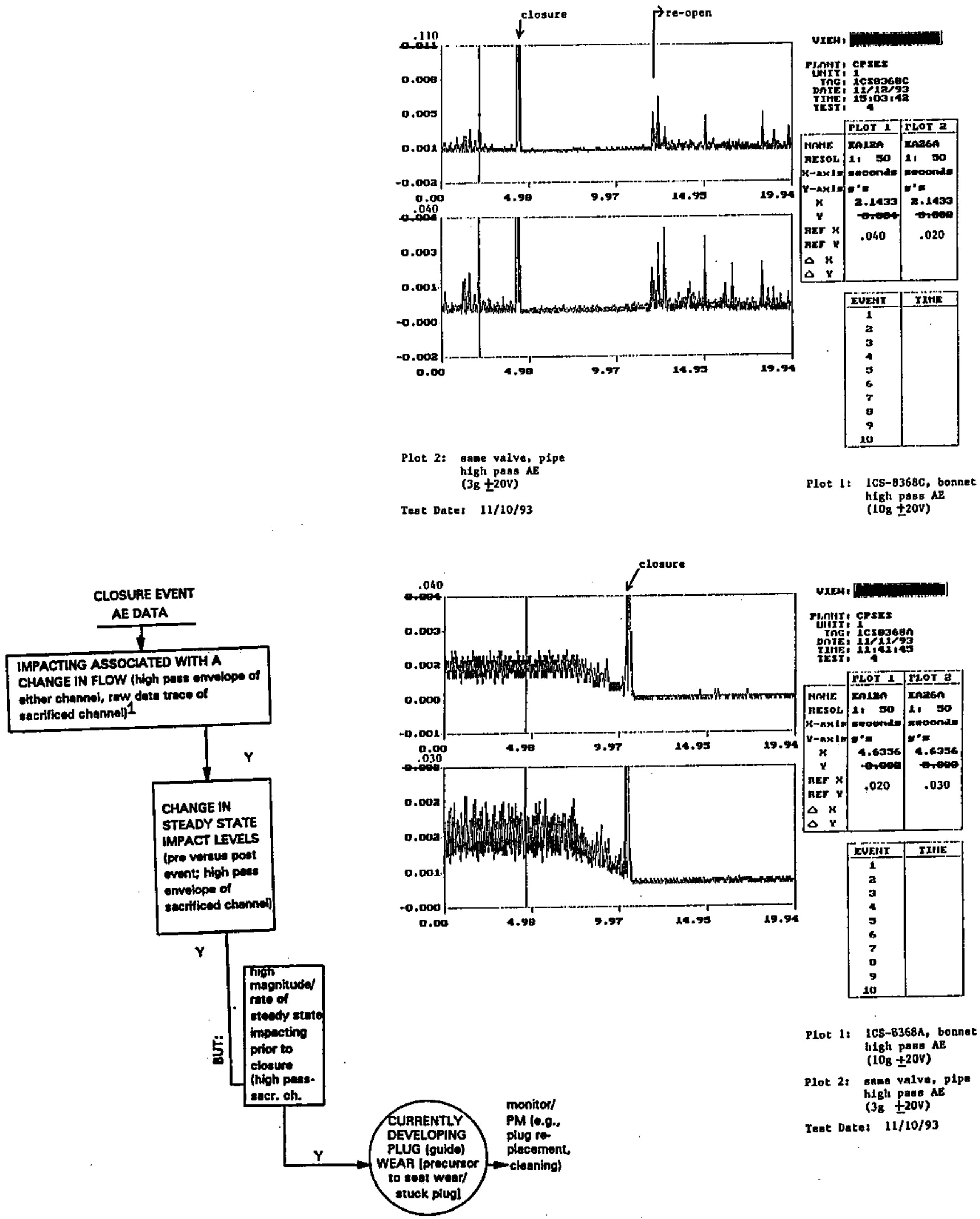

Figure 14. Plug wear—Evidence based on trace comparison between like valves 1CS-8368B and 1CS-8368A (both first in series, same test scenario, with 9 gpm through valve).

Modeling Valve Leakage

Steven R. Bell and Randall Rohrscheib
Illinois Power Company

ABSTRACT

The American Society of Mechanical Engineers (ASME) Code requires individual valve leakage testing for Category A valves. Although the U.S. Nuclear Regulatory Commission (USNRC) has recognized that it is more appropriate to test containment isolation valves in groups, as allowed by 10 CFR 50, Appendix J, a utility seeking relief from these Code requirements must provide technical justification for the relief and establish a conservative alternate acceptance criteria.

In order to provide technical justification for group testing of containment isolation valves, Illinois Power developed a calculation (model) for determining the size of a leakage pathway in a valve disc or seat for a given leakage rate. The model was verified experimentally by machining leakage pathways of known size and then measuring the leakage and comparing this value to the calculated value. For the range of values typical of leakage rate testing, the correlation between the experimental values and calculated values was quite good. Based upon these results, Illinois Power established a conservative acceptance criteria for all valves in the inservice testing (IST) program and was granted relief by the USNRC from the individual leakage testing requirements of the ASME Code. This paper presents the results of Illinois Power's work in the area of valve leakage rate testing.

INTRODUCTION

Although individual valve leakage rate testing has been required at nuclear power plants for some time, little effort has been directed at determining appropriate leakage criteria for individual valves or even evaluating the usefulness of this testing. This paper represents an initial attempt by Illinois Power to provide some insight into the parameters associated with leakage testing in order to assess the appropriate tests to be performed. This paper also includes a discussion of the development of the leakage rate model and the experiments that were performed in verifying this model, the preparation of the Relief Request (approved September 25, 1992), and the economic impact produced by this method of testing during the fall 1993 refueling outage.

One of the initial difficulties encountered in addressing leakage rates is that personnel conducting the tests generally work in metric units (standard cubic centimeters/minute, sccm), while engineering and management personnel are generally inexperienced with this terminology. As a result, a leakage rate of 20,000 sccm "sounds like" a significant leak. In fact, this is a fairly small hole. Because of this lack of familiarity, both English and metric units are used in this paper, so that the reader will better understand the relationships between english units and the metric equivalents commonly used in this type of testing.

LEAKAGE RATE MODEL

Section XI of American Society of Mechanical Engineers (ASME) Code, Subsection IWV-3420, Valve Leakage Rate Testing, requires leakage rate testing for valves where leakage must be limited to a specific amount to allow the valves to fulfill their safety function. Subsection IWV-3423, Differential Test Pressure, requires leakage rate testing be performed with the system pressure

differential in the same direction as when the valve is performing its function.

The U.S. Nuclear Regulatory Commission (USNRC) has concluded that the applicable leakage rate test procedures and requirements for containment isolation valves are determined by 10 CFR 50, Appendix J. The ASME Code requires individual valve leakage rate tests, while 10 CFR 50, Appendix J, allows testing of valves in groups. By establishing conservative acceptance criteria for a valve group (containment penetration) such that none of the valves can be significantly degraded and still pass the test, considerable savings in personnel radiation exposure and scheduling flexibility can be achieved. This approach can be shown to provide equivalent levels of quality and safety to those achieved through individual testing. As the purpose of these valves is to isolate the containment, testing in groups (i.e., by containment penetration) would verify the integrity of the containment boundary. By establishing conservative acceptance criteria, the condition of the valves can also be established within reasonable limits by this method.

Work on this approach began with discussions between the plant testing personnel and engineering staff responsible for the inservice testing (IST) program. Experience with testing had indicated that valves with leakage rates on the order of 5–20,000 sccm could generally be found to have some visible minor evidence of seat degradation. By contrast, tests where leakage rates above 20,000 sccm were recorded were always accompanied by noticeable seat degradation or a failure in the test lineup. What this told us was that, conceptually, we shouldn't be spending our money on repair of valves until leakage approached at least 5,000 sccm. Further, repair of valves with leakage in the range of 5–15,000 sccm should be considered only if total containment leakage was nearing the Appendix J limits. Although this appeared to make "good sense," we recognized that more technical justification would be required to demonstrate that this approach would not allow us to miss a significantly degraded valve in a penetration line-up that included multiple valves. To do this, we needed to determine if there was any relationship between valve size and leakage in the range of interest.

To accomplish this analysis, we modeled the leakage path as a square-edged orifice. This assumption is representative of a scratch across a valve seat made by an abrasive particle or the type of leakage path that a local leakage rate test (LLRT) is designed to measure.

Using the Bernoulli obstruction theory for a generalized flow obstruction, we could solve for the orifice size, at the test pressure, which would account for the leakage rates of interest.

The following nomenclature will be used in Equations (1) through (4):

Q	=	flow rate in standard cubic centimeters per minute (sccm)
(P1-P2)	=	pressure differential in pounds per square inch diameter (psid)
X	=	density of the medium in pounds-mass per cubic foot (lb_m/ft^3) (for this calculation the test medium is air with an assumed density of 0.076 lb_m/ft^3) (Bolz and Tuve, 1976)
D1	=	full diameter of the test or component body
D2	=	orifice or corrosive particle diameter
A1	=	cross-sectional area of the test or component body
A2	=	cross-sectional area of the orifice
π	=	numerical constant 3.14159.

From White (1986), we obtained the general formula for leakage:

$$\frac{Q}{A2} = \sqrt{\frac{2(P1 - P2)}{X\left[1 - \left(\frac{D2}{D1}\right)^4\right]}} \quad (1)$$

Solving for $(D2)^2$ we obtained the following expression:

$$(D2)^2 = \left(\frac{4}{\pi}\right)A2 = \left(\frac{4}{\pi}\right)\left[\frac{Q}{\sqrt{\frac{2(P1-P2)}{X\left[1-\left(\frac{D2}{D1}\right)^4\right]}}}\right] \quad (2)$$

Because the orifice diameter, D2, is very small in relation to the component diameter, D1, the term

$$\left[1 - \left(\frac{D2}{D1}\right)^4\right] \quad (3)$$

can be considered approximately equal to 1.

This further simplifies the expression for $(D2)^2$ to the following:

$$(D2)^2 = \frac{4}{\pi}\left[\frac{Q}{\sqrt{\frac{2(P1-P2)}{X}}}\right] \quad (4)$$

Inserting numerical values of 9 psid (LLRT pressure) and 20,000 sccm (leakage rate of interest) and the appropriate conversion factors yields the following:

$$(D2)^2 = \frac{4}{\pi}\left[\frac{20{,}000\ \frac{cm^3}{min}\left(\frac{1\ in.}{2.54\ cm}\right)^3}{\sqrt{\frac{2\left(9\frac{lb}{in.^2}\right)\left(\frac{32.2\ ft}{s^2}\right)\left(\frac{12\ in.}{1\ ft}\right)\left(\frac{60\ s}{1\ min}\right)^2}{0.076\frac{lb}{ft^3}\left(\frac{1\ ft}{12\ in.}\right)^3}}}\right]$$

$$(D2)^2 = 2.06 \times 10^{-3}\ in.^2$$

$$D2 = 0.045\ in.\ \text{or slightly under}\ 3/64\ in. \quad (5)$$

Therefore, an orifice of this size is approximately equal to the size of the maximum leakage path allowed, using an acceptance criteria of 20,000 sccm.

This theory is based on the assumptions of incompressible, steady, frictionless flow. The validity of these simplifying assumptions for the range of test parameters of concern for valve testing (small differential pressures and low flow rates) was verified via experimentation using an LLRT test rig and precisely machined orifices of various sizes. The results of this experimentation are tabulated in Table 1 and compared with calculated values using the same flow rates and differential pressures.

As Table 1 shows, the error between the calculated data and the experimentally measured data is acceptable. The Bernoulli model used in this calculation may be considered ideal and is not necessarily identical to what is encountered in the field. However, for the range of values required, the additional effects of nonideal conditions, such as friction and compressibility, are negligible when compared with field conditions and instrument accuracies.

A further evaluation of this data for "reasonableness" was done using Illinois Power's reactor coolant system as an example. This system is equipped with a filtering system (reactor water cleanup system.) The filtering system uses an 18-micron filter. This means that particles expected in the system would be less than this size, or approximately 0.00071 in. If abrasive particles of this size were dragged across the valve seat during valve closure cycles,

Table 1. Data comparison.

Flow (sccm) (±3%)	DP (psid) (±3%)	Test diameter[a] (in.)	Calculated diameter (in.)	Differential (test-calculation)/test (%)
1,950	9.48	0.0156	0.0139	10.9
7,000	9.45	0.0313	0.0263	16.0
94,000	5.00[b]	0.125	0.1130	9.6

a. Nitrogen testing medium, density = 0.07307 lb_m/ft^3 (Bolz and Tuve, 1976).

b. This was the highest differential pressure the LLRT stand could maintain at this large of an orifice size.

approximately 100 scratches of "normal" size would be required before the valve failed its leakage rate test. Another way of viewing this is that a single leakage path necessary to cause a failure must be the result of a particle 100 times the normal particle size in the system. Given our knowledge of system cleanliness and experience with actual testing, these seem like "reasonable" criteria. Further, the use of the 20,000 sccm criteria will allow adequate monitoring of valves in groups, because the leakage paths of interest are caused by very small scratches and are unrelated to valve size.

ECONOMIC IMPACT

According to the Clinton Power Station Supervisor of Plant Technical, an average LLRT costs about $5,000. Therefore, the elimination of unnecessary LLRTs provides a direct cost benefit, eliminates potential critical path work, and frees personnel for other activities. Conservatively, we saved about $100,000 in our last refueling. These savings will continue for the life of the plant.

CONCLUSION

The results of this work have lead to an increased understanding of the type of valve sealing surface irregularities that an LLRT is designed to measure. It is important to realize that the amount of leakage detected by an LLRT is produced by tiny surface abrasions and scratches on the mating surface of the disc and seat. A valve that has a seriously damaged internal part, that fails to seat properly, or that sticks in an intermediate position will produce gross leakage far in excess of that which an LLRT can measure. This work has allowed for a meaningful leakage rate acceptance criteria to be established that is sufficiently conservative to detect valve degradation but is not so conservative that unnecessary valve maintenance is performed. Further, it has provided the technical justification for USNRC acceptance of our Relief Request 2034, which significantly reduced the work needed to meet the inservice inspection requirements mandated by the ASME Code. The text of the relief request is included as an appendix. The information and equations stated in this paper were used to justify the relief request.

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Appendix

Illinois Power Company Relief Request

APPENDIX

ILLINOIS POWER COMPANY
Clinton Power Station

ASME Section XI Relief Request

RELIEF REQUEST 2034

Component Information

All Section XI, Category A containment isolation valves which require a leakage test per IWV-3420 as identified in Illinois Power's Pump & Valve Testing Program Plan.

Code Requirements

The ASME Code Section XI, Subsection IWV-3420, Valve Leakage Rate Testing, requires leakage rate testing for valves where leakage is limited to a specific amount in fulfillment of their safety function. Subsection IWV-3423, Differential Test Pressure, requires leakage rate testing be performed with the system pressure differential in the same direction as it is when the valve is performing its function.

Relief Request/Justfication

Illinois Power Company requests relief from the Code requirements for the following reasons: The Nuclear Regulatory Commission has concluded that the applicable leakage rate test procedures and requirements for containment isolation valves are determined by 10 CFR 50, Appendix J. The ASME Code requires individual valve leakage rate tests, while 10 CFR 50, Appendix J allows testing of valves in groups. By establishing conservative acceptance criteria for a valve group (containment penetration) such that none of the valves can be significantly degraded, considerable savings in personnel radiation exposure and scheduling flexibility can be achieved. This approach is of benefit to Illinois Power and provides equivalent levels of quality and safety to those achieved through individual testing. As the purpose of these valves is to isolate the containment, testing in groups, i.e., by containment penetration, would verify the integrity of the containment boundary. By establishing conservative acceptance criteria, the condition of the valves within reasonable limits can also be established by this method.

Alternate Testing Proposed

The maximum permissible leakage rate for a specific containment penetration (inboard and outboard isolation valves combined) will be specified utilizing conservative acceptance criteria which allows for detection of valve degradation within reasonable limits instead of a leakage rate for the individual valves as required by IWV-3426, Analysis of Leakage Rates. Attachment 1 to this relief request provides a technical basis for the acceptance criteria. The evaluation of test results will be based on the penetration leakage rate (inboard and outboard isolation valves combined) instead of on the individual valve leakage rate as required by IWV-3427, Corrective Action.

Verifying Check Valve Position with Radiography

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ABSTRACT

This paper presents the results of a program used at Grand Gulf Nuclear Station for verifying the positions of check valve disks using radiography. Valve position verification using radiographs meets the requirements of Section XI, IWV-3522, and OM Code, ISTC 4.5.4, for verifying disk position by "other positive means" when more typical methods such as flow, differential pressure, and external position indicators cannot be used. The method is particularly suitable for small valves (up to 6-in. nominal pipe size) and does not require special preparations, such as removal of insulation. This paper discusses advantages, disadvantages, costs, equipment, and manpower requirements for performing radiography of check valve disks. Sample radiograph images, showing typical internal details, are included.

INTRODUCTION

At Grand Gulf Nuclear Station (GGNS) we require exercising a check valve to the position required to perform its safety function. In some cases it is not possible or practical to exercise these valves during plant operation. Various exercising options are allowed in accordance with the applicable code, or relief to code requirements can be requested. Confirmation that the disk is in the required position can be determined by visual observation, an appropriate indicator that signals the change of disk position, or indirect evidence that signals the change of system pressure, flow rate, or level, which reflects disk position, or by other positive means.

In 1991, the U.S. Nuclear Regulatory Commission (USNRC) notified the industry that exercising stop-check valves to the closed position could no longer be performed by using the handwheel, unless that was the way the valve would be closed during an accident. As a result, GGNS identified several valves that could not be exercised as required. These valves were disassembled and the internals inspected to verify the valve disk movement capability. Other positive means of verification were investigated based on the cost and radiation exposure received during disassembly and inspection.

CHOOSING THE PROCESS

We looked at what could be done to improve the process and still meet the requirements of the USNRC. In meeting the requirements of the customer (USNRC), a plan was made to pursue two possible alternate methods for testing the valves. First, a mock-up flow loop was set up on a 2-in. "Y" pattern stop-check valve. Nonintrusive testing was used to monitor disk position with acoustics and ultrasonics. Second, radiography was performed on a 2-in. "Y" pattern stop-check valve in the open and closed positions. The radiography was performed in a controlled environment to develop the best technique and to obtain the clearest resolution. The efforts of our Quality Programs department in developing a radiography technique allowed this second option to be available.

The results of these actions determined that both methods were acceptable methods of verification. Further review of both processes determined that radiography would be the first choice and acoustic and ultrasonic methods would be second. This decision was closely coordinated

with Quality Programs because of the additional work load that would be put on them. All parties agreed that radiography was in Entergy's best interest.

IMPLEMENTATION OF PROCESS

During the fifth refueling outage at GGNS, 19 stop-check valves were radiographed for position verification instead of using disassembly and inspection. Presently, eight stop-check valves are radiographed every quarter during normal plant operation. Relief had been granted to disassemble these valves during a cold shutdown or refueling outage.

ADVANTAGES

Positive Means of Verification

Position verification using radiography during valve operation ensures that the valve is in the actual, or required, safety position. Disassembly and inspection verify only that nothing is visible inside the valve that would prevent the valve from performing its safety function. Figure 1 is a radiograph of a 3/4-in. stainless steel stop-check valve in the closed position. Figure 2 is a radiograph of a 2-in. carbon steel stop-check in the full open position. Figure 3 is a radiograph of a 3-in. simple swing-check valve in the closed position. All radiographs were taken while the associated pumps were running during scheduled surveillance tests.

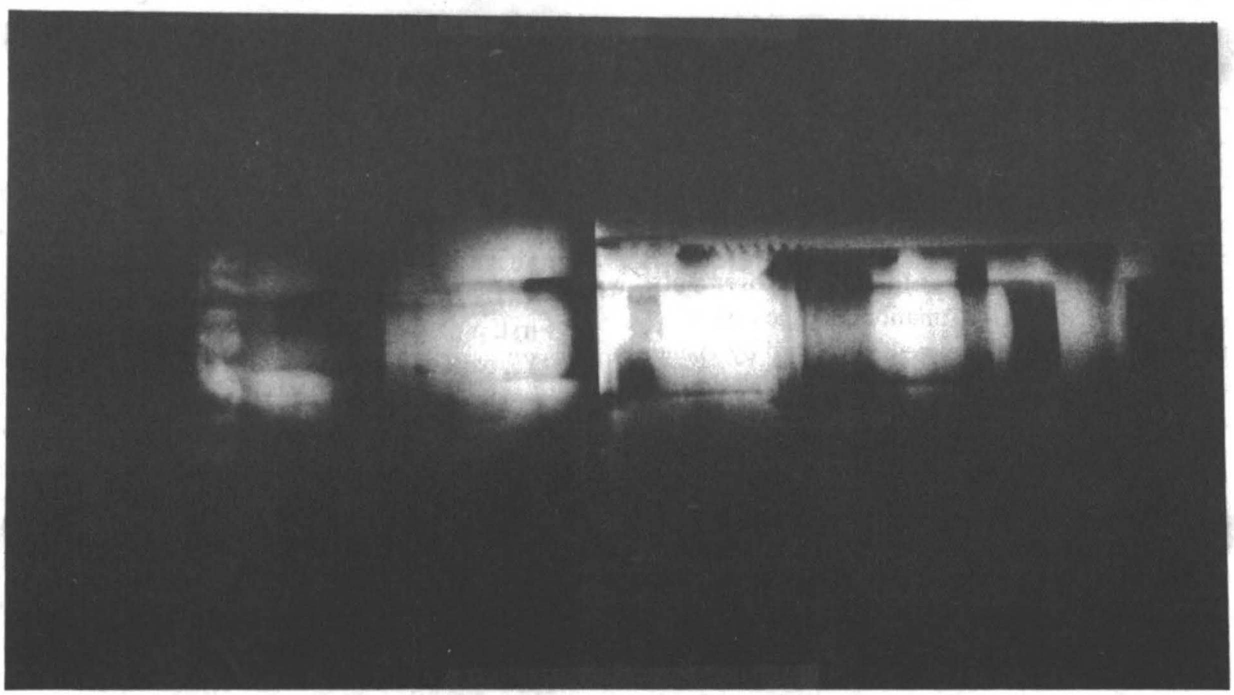

Figure 1. Radiograph of a 3/4-in. stop-check valve in the closed position. (Note: The gap between the end of the stem and the inside of the disk reveals that the disk has room to move in the open direction.)

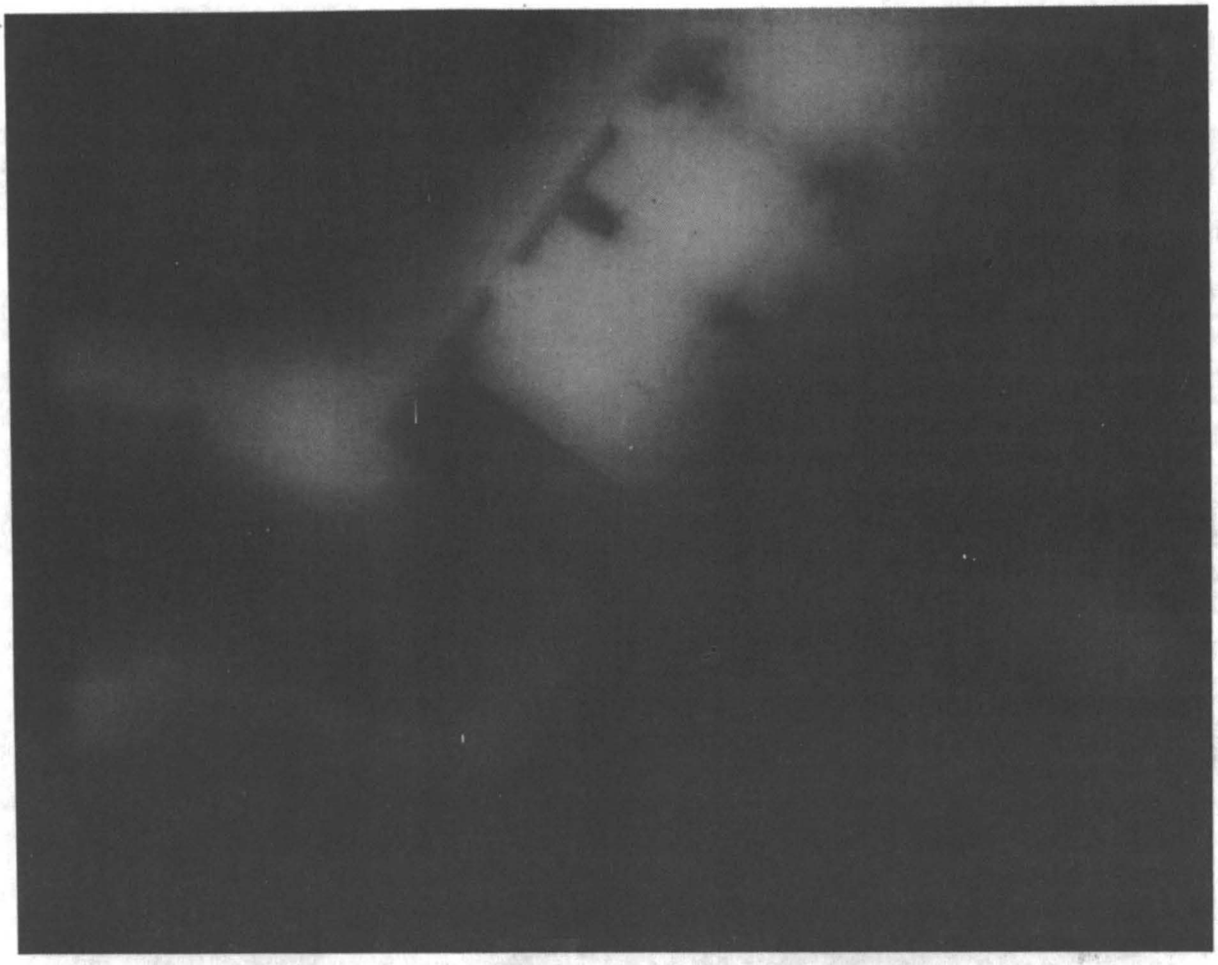

Figure 2. Radiograph of a 2-in. stop-check valve in the open position, taken with flow through the valve. (Note: The gap mentioned in Figure 1 is not present revealing a full-open position.)

Cost Reduction Over Disassembly

To simplify the examples, two categories of valves have been defined: best case and worst case.

For the best case, the check valve is not located in a radiological area and does not require additional support services, such as building a scaffold or insulation removal. The estimated costs for disassembly and inspection are

Total labor cost	$1,035.00	(26.91 staff hours)
Engineering support	$520.00	(20 staff hours)
Modification support	$469.00	(20 staff hours)
Health physics support	$160.00	(10 staff hours)
Quality support	$300.00	(15 staff hours)
Supervision	$25.00	(1 staff hour)
Total cost estimate	$2,509.00	

Figure 3. Radiograph of a 3-in. simple swing-check valve in the closed position.

The cost of radiography for this valve is estimated at $800.00, which results in a savings of $1,700.00 per test.

For the worst case, the check valve is located in a radiological area requiring support services, such as building a scaffold and removing insulation. The estimated costs for disassembly and inspection

Total labor cost	$4,276.00	(118.32 staff hours)
Engineering support	$520.00	(20 staff hours)
Modification support	$469.00	(20 staff hours)
Health physics support	$400.00	(25 staff hours)
Quality support	$300.00	(15 staff hours)
Supervision	$150.00	(6 staff hours)
Total cost estimate	$6,115.00	

The cost of radiography for this valve is estimated at $800.00, which results in an estimated savings of $5,300.00 per test.

During RFO5, 11 worst-case valves and 7 best-case valves were radiographed as opposed to disassembly and inspection. The total savings during RFO5 was $70,211.00.

Dose Reduction Over Disassembly

The amount of dose that will be saved depends on the dose rate at the valve location. The estimated staff hours needed for disassembly and inspection of a check valve are 27 for the best case and 118 for the worst case.

The following example shows the exposure calculation:

27 hours in a 20 millirem field = 540 millirem

118 hours in a 20 millirem field = 2.36 rem.

Other Advantages

The following advantages illustrate the value of radiography over disassembly

- Reduces radiological waste
- Reduces maintenance and operations personnel work load
- Achieves compliance with the requirements of the ASME Code because seven of the valves can now be verified every quarter
- Reduces the potential of damage caused by the disassembly and reassembly
- Provides a retrievable permanent record of the actual disk position.

DISADVANTAGES

The following disadvantages can be listed for radiography:

- Used for position verification only. The condition of the valve internals cannot always be determined.
- Valve size limited.

The clarity of the radiograph decreases with an increase in valve size. A 6-in. piston check valve is the largest valve that GGNS has successfully radiographed for position verification. On check valves larger than 6 in., the time of exposure and strength of the source become too extreme to obtain the quality of radiographs needed.

- Impact to the surrounding work activities. In some cases the impact is greater than others, but in all cases the immediate area has to be cleared of all personnel.

EQUIPMENT AND STAFF REQUIREMENTS

Two radiography personnel and typically one person from the health physics department are required to support each radiograph. Support from operations may be needed to ensure that the valve's disk is positioned correctly. A 2-in. check valve requires around 200 curie-minutes of exposure at a 20-in. source-to-film distance. If all parties are coordinated, one valve can be radiographed and the film developed within one hour.

Onsite Nitrogen Testing of Main Steam Relief Valves

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ABSTRACT

Set point testing of main steam relief valves is typically performed by service vendors at offsite facilities that can handle contaminated equipment and develop the steam pressures and quantities necessary for this testing. Because of the risk of failures that require testing additional valves, this work sometimes can become a critical path.

In order to reduce outage impacts from this testing, Illinois Power worked with VECTRA Technologies, Inc. (VECTRA, formerly Pacific Nuclear) to develop onsite test capabilities using nitrogen. As a result, all as-found testing was completed within 3 weeks of the outage start (eight valves were tested as a result of a failure in the first sample). However, all testing was completed in the time allotted to ship the valves off and obtain results from the first sample. Additional savings will result from the use of onsite craftsmen to refurbish the valves.

This paper presents the results of Illinois Power Company's successful effort to perform onsite nitrogen testing of main steam relief valves. The paper includes discussions of the analytical work necessary to develop the correlations between the use of nitrogen versus steam, the regulatory effort necessary to implement this process, the equipment needed, the economics of onsite testing, and the results from our refueling outage testing during October 1993.

INTRODUCTION

In 1982 the Electric Power Research Institute (EPRI) conducted a survey on practices employed by utilities for set point testing of safety valves.[a] This survey found that 62% of the utilities that responded removed safety valves and used a test facility to verify set pressure. Furthermore, 80% of this population used air or nitrogen as the test media. Since then, the use of nitrogen for testing safety and relief valves has been declining. The 1986 Edition of Section XI of the American Society of Mechanical Engineers/ Americans National Standards Institute (ASME/ ANSI) Boiler and Pressure Vessel Code mandates the requirements of ASME/ANSI OM-1-1981 (Part 1 of Appendix I for more recent code editions) for pressure relief device testing. OM-1 stipulates that relief valves should be tested with the same media and environmental conditions experienced while inservice. OM-1 allows an alternative media to be used, provided that the correlation between the test media and service media/environmental conditions is established and certified. Because this correlation information was not readily available for most of the valve makes and models installed at commercial nuclear facilities, nitrogen testing of the safety relief valves was discontinued as stations

a. Set point testing of safety valves using alternative test methods, NP-4235, Electric Research Power Institute, 1982.

previously using this method updated to the 1986 or more recent editions of Section XI.

The past practices used at Illinois Power's Clinton Power Station (CPS) to test safety relief valves are typical of many U.S. nuclear plants. CPS is a BWR-6 and has 16 Dikkers Model G471-6/125.04 safety relief valves (SRVs) installed between the reactor pressure vessel and the main steam isolation valves. During refueling outages, an initial sample of four valves would be removed, packaged, and shipped to a test facility. Each valve set point was verified using steam as the test media with an acceptance criteria of $\pm 1\%$ of nameplate set pressure. In accordance with ASME Section XI, IWV-3513, failure to meet the acceptance criteria resulted in removal of additional valves to increase the sample size. A typical refueling outage schedule does not contain enough time to allow for an initial sample, a second sample, and replacement of all valves that would be required if a failure occurred in the second test sample. Therefore, the policy at CPS was that if a failure occurred during the first test sample, all the remaining valves would be replaced with pretested spares. Following this policy resulted in replacement of all 16 valves in each of the first three refueling outages at CPS.

In the summer of 1992, a maintenance supervisor from CPS visited Kernkraftwerk Leibstadt (KKL), a Swiss BWR-6 very similar in design to CPS, to observe refueling activities. KKL's refueling outages are completed in an average of 44 days, and CPS wanted to see what lessons could be learned from our sister plant in Switzerland. One of the practices used at KKL appeared to be directly transferable to CPS because KKL uses the identical model of Dikkers SRVs as CPS. Switzerland does not have steam test facilities with sufficient capacity to perform set pressure testing of these valves; therefore, KKL uses nitrogen as the test media. CPS personnel recognized that performing valve testing on site and conducting refurbishment activities with in-house personnel could significantly reduce costs and possibly reduce outage schedule impacts. With these goals in mind, CPS prepared a bid specification that included engineering and technical support for development of steam-to-nitrogen correlation factors, design and fabrication of the necessary test equipment, and oversight of the testing and refurbishment of main steam SRVs. The successful bidder on this project was VECTRA.

CODE CONSIDERATIONS

ASME Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," involves the use of either (a) ASME Performance Test Code (PTC) 25.3-1976 or (b) ASME/ANSI OM-1 (or Part 1), depending on the edition of the Code used to perform inservice inspection and testing. Section 0, "Introduction," of PTC 25.3-1976 states, "It should be noted that if the temperature of the medium used to test the valve differs substantially from the temperature to which the valve is subjected while in service, the opening and closing pressure as well as blowdown will be different from the test pressures. In this case, it is necessary to develop appropriate corrections for the valve under test to account for these differences which is outside the scope of this code." Article 4 of Part 1 of the 1987 OM Code entitled "Test Methods" states in Paragraph 4.1.1.1: "Valves designed to operate on steam shall be set pressure tested with saturated steam. Alternative compressive fluids may be used as the test media, provided correlation data between the alternative fluid and steam has been established. The requirements of Para. 4.3 will apply for testing with alternative test media."

Although CPS is currently committed to PTC 25.3-1976 for inservice testing of SRVs, the requirements of OM-1 were used for guidance during the project.

To minimize the impact of having to increase the number of samples because of test failures, the set point tolerance used for inservice testing had to be increased. The tolerance of $\pm 1\%$ used before in the inservice testing program was based on CPS Technical Specification operability criteria. A change to $\pm 3\%$ was supported on a generic basis by General Electric Company (GE) Topical Report NEDC-31753P, "BWROG Inservice Pressure Relief Technical Specification Revision

Licensing Topical Report." As the title implies, this report was intended to be used to change the technical specification to allow ±3% margin in SRV set point. The GE report and the subsequent U.S. Nuclear Regulatory Commission (USNRC) safety evaluation of the report required a plant-specific analysis to further support a licensing amendment submittal. Illinois Power contracted with GE to perform the plant-specific analysis in January of 1993. The fourth CPS refueling outage was scheduled for September 26, 1993, and it was apparent that there would not be enough time between receipt of the GE analysis and the start of the outage to get a technical specification change for SRV set point tolerance. A meeting was held with the USNRC in May 1993 to discuss using ±3% tolerance to determine when an increased test sample was required for inservice testing while maintaining a ±1% tolerance for operability determination in the technical specification. While the USNRC agreed that this approach was within the intent of the safety evaluation, they also felt the discrepancy in tolerances between technical specifications and the inservice training program required relief from ASME requirements.

A relief request was submitted in July 1993 requesting the use of Paragraph 1.3.3.1 of Part 1 of ASME/ANSI OM-1987 (OM-1) to determine when additional tests are required. The relief request stated that when the technical specifications were revised to reflect a ±3% tolerance, the relief request would no longer be required. The relief request was granted on September 13, 1993.

NITROGEN TESTING DEVELOPMENT

In late 1980, Addenda I to the Dikkers SRV Instruction Manual, G471-6/125.04:10, was issued to provide "the required information and instructions to verify or adjust the set pressure of an SRV with nitrogen." Addenda I was based on the nitrogen-set correlation testing performed by the Technical Research and Development Department of Dikkers Valves for their Model G471-6/125.04 SRV. This correlation development is detailed in Dikkers' Technical Report TAO-313-GR, "Nitrogen-Steam Correlation Test." To ensure that the requirements of OM-1 were fully satisfied by Dikkers' correlation effort, VECTRA obtained the original Dikkers Technical Report.

To determine the correlation formula, Dikkers tested eight valves that had passed the certification tests required in a newly manufactured valve. Each valve was set-pressure tested with nitrogen four times, without adjustment, at two different ambient temperatures (40, 70, or 100°F), for a total of eight tests per valve, or 64 total tests.

The test results were averaged for each valve at each of the test temperatures, resulting in 16 data points. Each valve was then set-pressure tested with saturated steam four times, with no adjustment between tests, at an ambient temperature of 135°F. Again, the individual tests were averaged to produce eight data points. The ratio of nitrogen data points to steam data points was calculated, and a statistical analysis of the data was performed.

A linear regression provided the following correlation equation:

$$P = (1.02908 - 0.00017*T)*NPS \ ,$$

where

P	=	set pressure for nitrogen (psig)
T	=	valve temperature (°F)
NPS	=	stamped set pressure for steam (psig).

Based on the statistical analysis, Dikkers also developed correlation curves for several different nameplate set pressures. These curves were generated based upon a 95% confidence and a ±1% tolerance in nameplate set pressure.

VECTRA performed a thorough independent review of the Dikkers test report. This review consisted of (a) certification of Dikkers' correlation procedure and methodology; (b) verification

that documentation of all tests performed was properly maintained (including test instrumentation accuracies) and the results were provided with the report; (c) verification that appropriate statistical data reduction and analysis were performed; (d) numerical verification of the established correlation formula and confidence limits; and (e) performance of additional statistical analysis to determine correlation impact resulting from imposing certain data exclusion criteria, or limiting the applicable temperature range over which the SRVs may be tested with nitrogen. VECTRA determined that Dikkers' correlation development program and subsequent statistical analysis, with regard to set pressure testing and adjustment, was satisfactory. The correlation would comply with the Code and support the use of nitrogen as an alternative testing media for CPS's Dikkers SRVs.

To support nitrogen testing onsite, VECTRA fabricated the nitrogen test stand (Figure 1), operator control panel (Figure 2), and specialty flanges and tooling required to perform as-found testing, valve refurbishment, and recertification testing. The fabricated test equipment is similar to that used by KKL and Dikkers, with design enhancements such as a mobile skid to provide flexibility in staging the test activities.

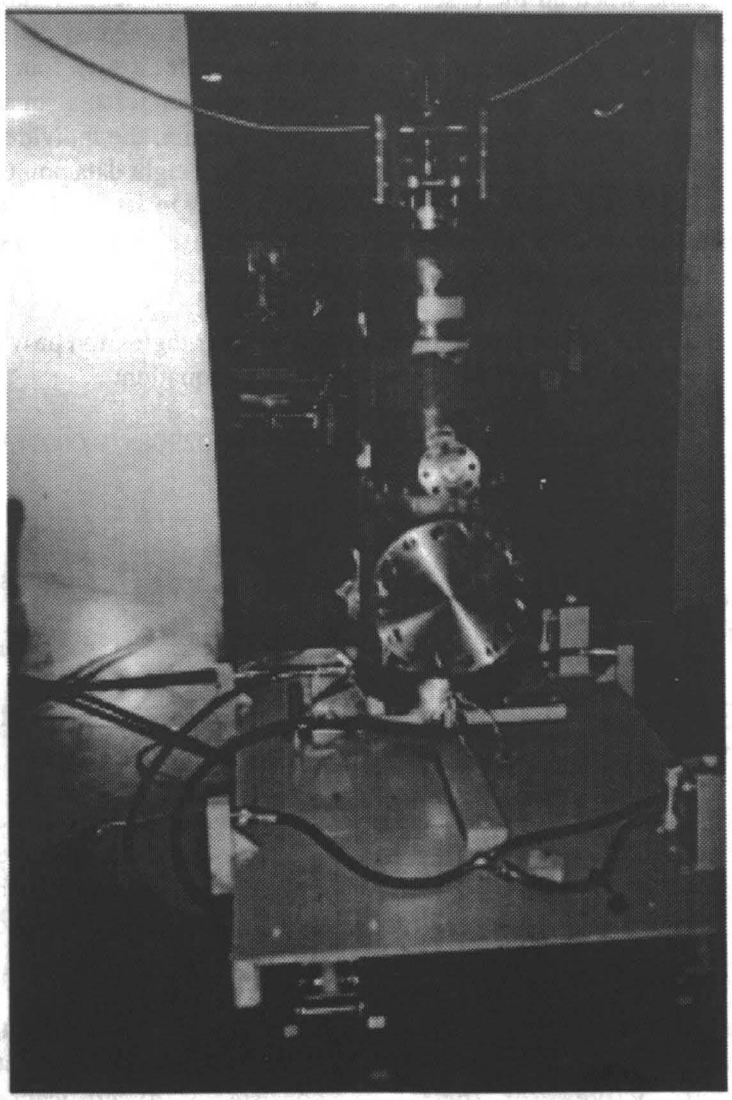

Figure 1. Nitrogen test stand.

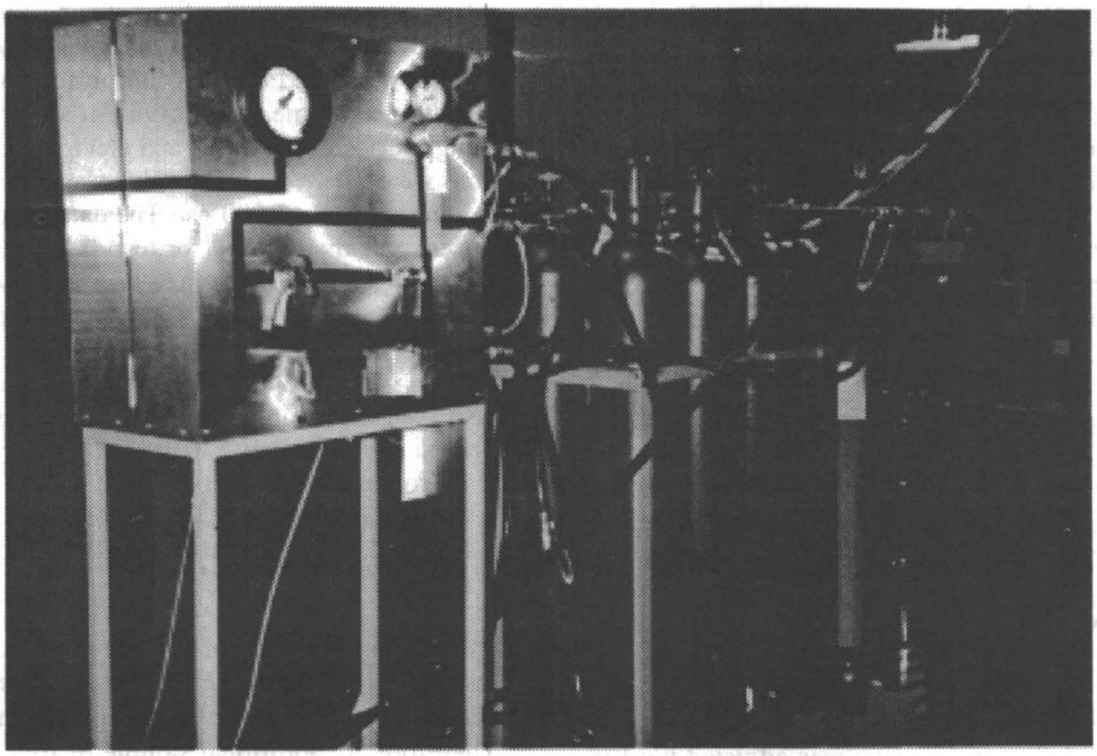

Figure 2. Operator control panel.

The test instrumentation consisted of a 0–3,000 psi ($\pm 0.25\%$) working transducer, a 0–3,000 psi ($\pm 0.10\%$) reference transducer (for calibration checks during SRV testing), two thermocouples, and an interface unit housing the necessary amplifiers and data collection system. A 0–15 scfh flow meter was used for seat leakage testing. The test equipment was calibrated with Illinois Power's calibration standards. Because the instruments were calibrated fully configured for testing, the accuracies established during the calibration process became the total loop accuracy for each instrument. The thermocouples were calibrated to within $\pm 2°F$, and the working transducer loop calibration over the region of concern was better than $\pm 0.20\%$.

ONSITE TESTING

After delivery from VECTRA, the testing equipment was moved to the basement of the Control Building. A rework and test area of approximately 40 by 14 ft was established as a contamination area.

Inside the rework area, a modular enclosure 12 ft wide by 16 ft long by 10 ft high was erected. This enclosure was fabricated using 1-1/4 by 1-1/4-in. angle iron for the frame and 22 gauge stainless steel for the skin. A 3-ft door allowed personnel access and two 3 by 10-ft doors on one end provided access for the valve and test skid.

The enclosure served as a test cell, with the computer, nitrogen control panel (with pressure transducers), amplifiers and the nitrogen supply setup outside the contaminated area. A 2-in. penetration in the modular enclosure is used to route the nitrogen hoses and thermocouple cable from the noncontaminated area into the enclosure. Additionally, this enclosure is used for contamination control and personnel safety because the nitrogen gas was released at a high energy level and was potentially contaminated. During testing, the enclosure was sealed and a slight negative pressure was provided by a large HEPA filter unit taking suction through a 7-in. penetration. The atmosphere inside the enclosure is sampled by a continuous monitor. Although the enclosure provides a physical barrier to isolate testing

personnel from the expelled gas, it does not eliminate the need for hearing protection.

The valve was mounted on the skid outside the enclosure using a 5-ton hoist. Once the valve was mounted, the skid was wheeled inside the enclosure. The nitrogen hoses were attached to the test flange; the thermocouple was mounted on the valve body; and the flow meter was attached to the enclosure near a sight window facing the panel.

For the as-found seat leakage test, the setup involved installation of blind flanges on the valve outlet and sub exhaust flanges. A leak detection flange was installed in place of the nozzle ring locking bolt. The valve was then pressurized to 90% of the calculated N_2 set pressure. After 5 minutes of maintaining pressure, the leakage was recorded. The acceptance criteria was <6 scfh.

To perform the set pressure test, the two blank flanges and the leak detection flange were removed. The nozzle ring was adjusted until it contacted the liner. It was then backed off two or three teeth from the valve piston, and the locking bolt reinstalled. Adjustment of the nozzle ring was necessary to ensure that a good popping action occurred with the limited capacity available. The ambient temperature inside the test cell was recorded and the correlation formula was used to determine the equivalent set pressure using nitrogen. The hoses and electrical connections were verified and the valve was pressurized to approximately 1,000 psi. The data acquisition system was then started for test data collection. The nitrogen supply pressure was increased at a rate of 60 to 100 psi per second until the valve popped. The data acquisition was stopped, and the peak pressure (set point) measurement was displayed and recorded. After the valve was stabilized at approximately 850 psi, preparations were made for another set pressure test. A total of four tests were performed. After set pressure testing was completed, each valve received a final seat leakage test.

In the initial sample of four valves selected for testing during the refueling outage, one valve actuated outside the ±3% acceptance criteria. Therefore, an additional sample of four valves were removed and tested. The set pressure test results are summarized in Table 1 and the seat leakage tests are provided in Table 2. A graph of set pressure test results are included as Figure 3.

Table 1. Safety relief valve set pressure testing.

SRV serial number	Set pressure (psig)		Set pressure (psig)					
	Steam	N_2	1st	2nd	3rd	4th	Test average	Result
160942	1,165	1,184.2 @ 74°F	1,168.8	1,155.3	1,156.3	1,150.6	1,157.8 (–2.2%)	Sat
160540	1,165	1,184.2 @ 74°F	1,174.5	1,160.3	1,152.0	1,156.0	1,160.7 (–2.0%)	Sat
160790	1,180	1,199.5 @ 74°F	1,163.1	1,156.6	1,155.9	1,159.2	1,158.7 (–3.4%)	Unsat
160785	1,190	1,209.6 @ 74°F	1,207.8	1,214.7	1,210.6	1,211.1	1,211.1 (+0.1%)	SAT < ±1%
160911	1,180	1,199.5 @ 74°F	1,199.7	1,202.8	1,192.8	1,187.6	1,190.9 (–0.7%)	SAT < ±1%
160787	1,165	1,184.4 @ 73°F	1,181.1	1,177.6	1,178.5	1,183.6	1,180.2 (–0.4%)	SAT < ±1%
160943	1,165	1,184.4 @ 73°F	1,212.7	1,187.5	1,196.3	1,195.3	1,198.0 (+1.2%)	Sat
160791	1,180	1,199.7 @ 73°F	1,185.4	1,218.3	1,196.7	1,204.6	1,201.3 (+0.1%)	Sat < ±1%

Table 2. Safety relief valve leakage testing.

SRV serial number	Initial (scfh)	Final (scfh)	Results
160942	>15	>15	Unsat
160540	>15	>15	Unsat
160790	>15	Waived	Unsat
160785	5.75	2.5	Sat
160911	1.0	0.3	Sat
160787	2.5	0.5	Sat
160943	0.0	0.8	Sat
160791	0.0	0.8	Sat

By reviewing these test results, it can be seen that the first three valves tested had significant seat leakage, and all three valves tested low with respect to the nameplate pressure. This is to be expected because the leakage provides some additional prelift force, thereby reducing the pressure necessary to achieve the pop. Four of the remaining five valves, which had much lower leak rates. The four-test average of results was <±1% of nameplate.

Performing onsite testing of SRVs produces savings of both money and outage time. Before CPS's most recent outage, the time to remove, package, ship, and receive test results for the initial sample of four valves was 3 weeks. Using nitrogen test equipment onsite, the first four valves were completed 13 days after the outage started. The removal and testing of four additional valves took an additional 5 days. The ability to test these valves quickly resulted in replacing only eight valves instead of the 16 that would have been replaced in normal CPS practice. As testing and maintenance personnel gained experience, the amount of time for setting up and performing the tests diminished. Two

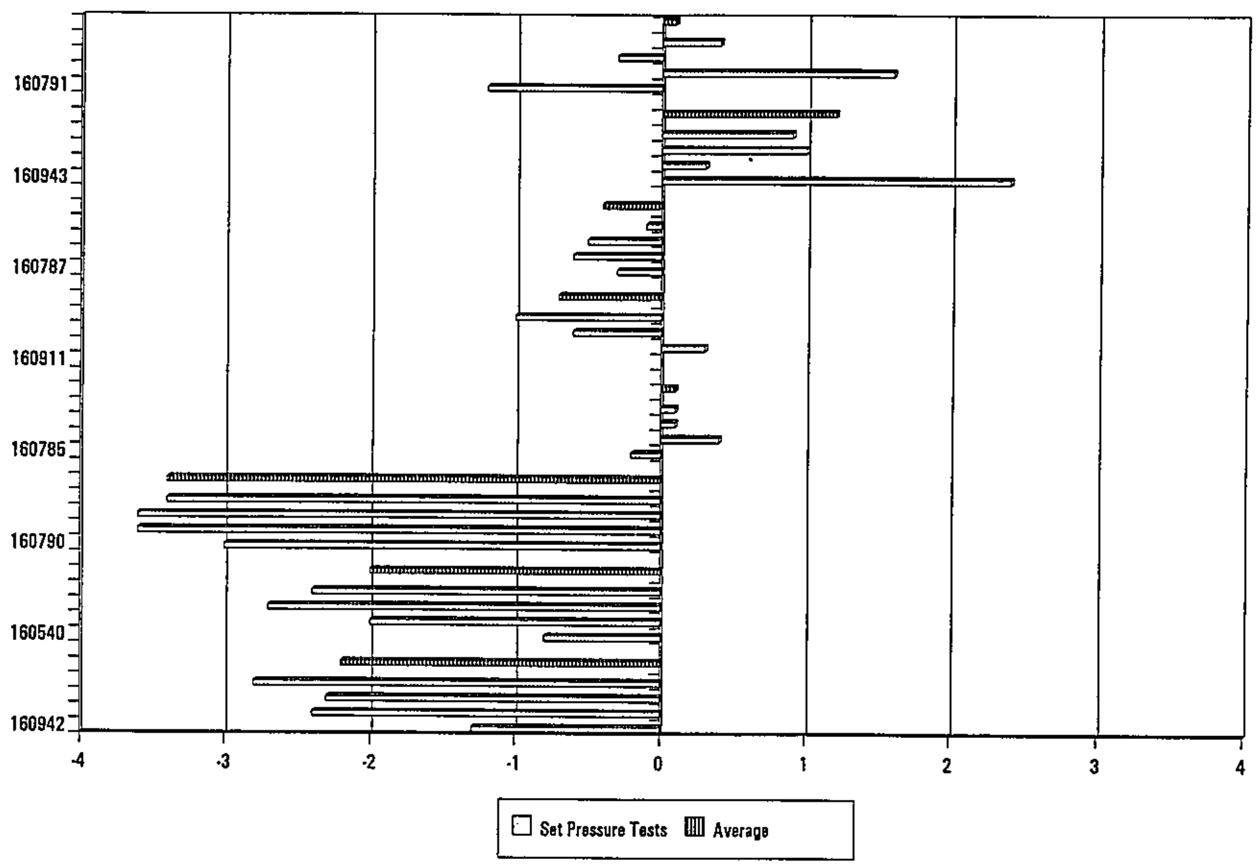

Figure 3. Set pressure test results.

valves could be tested during a 10-hour shift easily and three are possible with good coordination.

Using an offsite test facility and refurbishment contractor for 16 valves in RF-3 cost $429,000. Although refurbishment and recertification is not complete, the total cost for as-found nitrogen testing of eight valves was $198,000, of which $139,500 are one-time costs. The total projected costs for testing and refurbishment of eight valves, minus the startup costs, is $110,000. Assuming 16 valves could be tested for $220,000, $229,000 are saved from RF-3 costs by testing onsite and using in-house labor for refurbishment. Increasing the acceptance criteria from $\pm 1\%$ to $\pm 3\%$, combined with the schedule flexibility allowed by onsite nitrogen testing, resulted in replacing only eight of the 16 valves. This saved $296,000 in maintenance labor costs and nine person rem of radiation exposure.

TRANSFERABILITY

While the Dikkers correlation can be used to satisfactorily test Illinois Power's SRVs, it should be noted that the correlation equation and curves provided in Addenda I can only support nitrogen testing of the Dikkers model G471-6/125.04 SRV. No additional testing was performed by Dikkers to determine if the established correlation was generic to spring type SRVs. Although many similarities exist among spring type SRVs, the valve design and thermal characteristics of the different materials used between vendors and models would not intuitively support a generic correlation. However, correlations could be established for most spring type SRVs. Because testing SRVs with nitrogen is simple, cost-effective, and highly repeatable, any utility should seriously consider establishing a correlation to reduce outage time, operation and maintenance costs, and SRV testing impact.

Trending Check Valve Condition Via Acoustic Monitoring During Operating Flow

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ABSTRACT

A test program has been undertaken to identify trendable acoustic parameters and spectral characteristics, obtained during operating flow conditions, which are capable of indicating check valve degradation. Efforts were made to quantify changes in degradation sensitive acoustic parameters and spectral characteristics for various common types of check valves with artificially induced degradations. Acoustic data were acquired during steady-state operating flow with a single accelerometer and a portable, microprocessor-based, vibration data collector. Acoustic parameters and frequency spectra were calculated by the data collector and transferred to a computer database for analysis and trending. This methodology can be implemented in order to augment conventional, commercially available check valve diagnostic systems that can be difficult to apply on a regular basis, and typically require cycling a valve's state in order to analyze degradation.

INTRODUCTION

Check valve failures in nuclear power plant applications can cause major equipment damage resulting in plant down time and significant maintenance efforts. Degradation of check valve internal components, such as hinge pins, bushings, hinge arms or links, springs, disks, and disk stud nuts, usually results from instability of check valve disks during normal operating flow, and is typically responsible for check valve failures (Greenstreet et al., 1985; Haynes, 1991).

Based on results from inspections of utilities' check valve programs, the U.S. Nuclear Regulatory Commission has emphasized trending of check valve test results in order to detect degradation before significant problems occur. This implies that diagnostic testing should be applied on a regular basis, unless detailed knowledge of failure rates for specific check valves in specific applications has been developed and applied. In most cases it would be burdensome to regularly apply conventional check valve diagnostic systems on the most rapidly degrading check valves. Also, it becomes the analysts' responsibility to extract information from diagnostic signatures for trending purposes, and to maintain key test results. Conventional, commercially available check valve diagnostic systems typically require cycling a valve's state in order to fully analyze check valve degradation. Scheduling pump cycling in order to test check valves may impact plant operations, and in some cases may not be possible. Because a typical nuclear plant has hundreds of check valves, ideally any methodology employed for the purpose of monitoring should be noninvasive and simple to apply.

Acoustic data can be acquired from check valves during steady-state operating flow with a single accelerometer and a portable, microprocessor-based, vibration data collector (Allen and Carow, 1992). Acoustic parameters

and frequency spectra calculated by the data collector can then be transferred to a computer database for analysis and trending. A monitoring strategy consisting of regular trending coupled with the use of a diagnostic system that can fully analyze valve performance upon detection of worsening trends should focus maintenance activities on degrading valves and reduce failures. The computer database trending methodology discussed in this paper is intended to augment existing diagnostic systems. By extracting appropriate parameters during operating flow and observing their behavior over time, changes in acoustic activity will be noticeable. Analysis of trends can provide substantial information about the condition of a check valve. This information can be used to determine whether further measurements or testing are necessary in order to more thoroughly quantify valve condition, or whether corrective action should be taken.

A test program has been undertaken to identify trendable acoustic parameters and spectral characteristics, obtained during operating flow conditions, which are capable of indicating check valve degradation. Efforts were made to quantify changes in degradation-sensitive acoustic parameters and spectral characteristics for various common types of check valves, using artificially induced degradations. The valves were placed in a test loop in the waste-water treatment facility of a fossil-fuel fired power plant.

IMPACT DETECTION TECHNIQUES

Envelope Function

Detection of impacts caused by check valve internal parts is essential to effective application of monitoring techniques used to identify check valve degradation. In order to distinguish between impacting of check valve internal parts and flow noise in acoustic data, an envelope function was derived using Equation (1).

$$ENV_{(jN\Delta T)} = \frac{1}{N} \sum_{i=jN+1}^{(j+1)N} |X_{(N\Delta T)}| \qquad (1)$$

The envelope function is an ensemble of short-term averages of the absolute, or rectified, values calculated from sampled data. In this equation, $ENV_{(jN\Delta T)}$ is the average of the rectified signal from time jT to (j + 1)T where j = (0, 1, 2, ...). The short-term averaging time, T, is equal to some arbitrary number, N, times Δt, where Δt is the sampling interval. Typically Δt is on the order of 0.05 milliseconds, corresponding to a sampling frequency of approximately 20 kHz, and an analysis frequency of approximately 10 kHz. Experience has shown that the best short-term averaging time should be on the order of 2–10 milliseconds. An envelope function, computed with a short-term averaging time of 3 milliseconds, and the raw accelerometer data containing impact activity from which the envelope was obtained, are shown in Figure 1.

To determine when an impact occurred, the mean of envelope signal amplitudes was calculated. If a more rigorous analysis was done, the most probable value would have been used instead of the mean value, since the distribution function of envelope signals are skewed to higher values when impacting is occurring. In practice, the mean value has been found to be adequate. A threshold level was then set at two to four times the mean value. If the envelope signal exceeded this threshold, it was considered an impact. Impact rates were determined by dividing the total impacts detected over a time trace by the size, in seconds, of the time trace. The capability of this method to detect artificially induced impacts on an 18-in. check valve in nuclear service has been demonstrated (Allen and Carow, 1992).

Modified Amplitude Probability Distribution Function

Another impact signal detection technique is based on the assumption that the magnitude of an incoming accelerometer signal, containing only flow noise, is purely random. Under this assumption, the signal will exhibit Gaussian normal

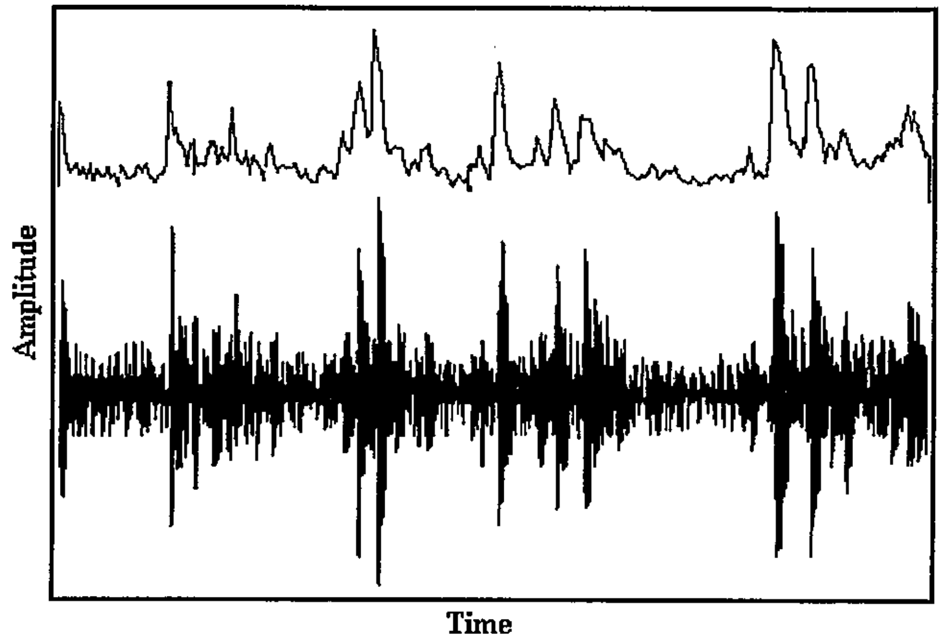

Figure 1. Envelope function and raw accelerometer time trace containing impacts.

statistical characteristics. The value of an amplitude probability distribution (APD) function at any voltage level, constructed from such an accelerometer signal, can be represented by Equation (2). In the equation, v represents a voltage level, and σ represents the standard deviation.

$$\mathrm{APD}(v) \quad \propto \quad e^{-\frac{v^2}{2\sigma^2}} \ . \qquad (2)$$

The computed APD should match the classic bell-shaped normal distribution curve when the number of occurrences of certain signal levels are plotted against the signal levels. The APD relationship can then be modified by taking the base 10 logarithm of both sides. The equation would then describe a linear relationship between the log of the APD, and the quantity $(v/\sigma)^2$, with the slope being $\log (e^{-0.5}) = -0.22$. This relationship describes the modified amplitude probability distribution (MAPD) function (Thompson and Quinn, 1985).

Based on the assumption that incoming flow noise signals should be purely random, MAPD slopes can be monitored in order to detect periodic events introduced into a signal, as well as the addition of other random signals, such as impacting of check valve internal parts. Analysis of MAPD slopes has been used to verify the proper operation of monitoring system data channels, and to detect low-level impacts in loose parts monitoring applications (Allen and Oesterling, 1989). Distorted signals caused by overloading or by strong 60 Hz components, typical of grounding problems, were shown to shift MAPD slopes toward −1.0. The additions of other random influences, such as impacting, were shown to move MAPD slopes toward less negative values.

POWER SPECTRAL DENSITIES

Power spectral density (PSD) is defined as the power per unit frequency interval (Harris, 1987). Random vibrations are generally considered to be the sum of a very large number of harmonic vibrations, with total power being equal to the sum of the power of component harmonic vibrations. The frequency distributions of power contained in incoming check valve accelerometer signals were computed via PSD calculations with amplitudes expressed in units of $g's^2/Hz$.

Dominant structural frequencies for the check valve body are known to be excited by random input associated with flow. The magnitudes of

power spectra at predominant valve body structural frequencies have been shown to increase when impacting of internal parts occurs, with the change in magnitudes related to the intensities of the impacting (Tullis, 1987).

In order to characterize flow and impact-induced excitations, the following PSDs were computed and examined:

- Impact PSD
- Background PSD
- Ratio PSD
- Envelope PSD.

When impacts were detected, Impact PSDs were calculated, from the raw accelerometer time signal, over the time that an impact occurred. Background PSDs were calculated for quiescent times in order to establish background levels. The ratios of Impact PSDs to Background PSDs, known as Ratio PSDs, were examined in order to compare the frequency content of the Impact and Background PSDs, and to reveal the dominant frequencies associated with impacting. Dominant frequencies associated with impacting are related to impact parameters, such as the mass of the impacting object and velocity of the impact, as well as the mounted sensor frequency response and the response of the impacted structure (Mayo et al., 1988).

Envelope PSDs were calculated from accelerometer time data after application of the envelope function [Equation (1)]. This effectively produced the PSD of an accelerometer signal low-pass filtered at a cut-off, or half-power, frequency of $1/N\Delta t$ Hz. For example, if a short-term averaging time ($N\Delta t$) of 3 milliseconds was used, the cut-off frequency would be 333 Hz. At frequencies above the cut-off, the Envelope PSD attenuates the true PSD by a factor proportional to a value between $1/f$ and $1/f^2$, where f is the frequency above the cut-off. This implies that potentially aliased frequencies could appear in the Envelope PSD if there is strong activity above the cut-off frequency. Additional information on filtering and aliasing is available in the literature (Bendat and Piersol, 1971). In general, Envelope PSDs were examined in order to detect changes in energy levels or the presence of impact signal periodicity.

TRENDABLE PARAMETERS

The parameters chosen in order to identify check valve degradation were primarily dependent on the amount of impacting detected in accelerometer signals.

Acoustic Parameters

The following primary acoustic parameters were obtained from accelerometer data:

- Impact Rate—Impacts can be identified by an increase in the amplitude of acoustic noise. If appropriate threshold levels were set, an impact rate can be determined by counting the number of impacts occurring over a set time period.
- Peak Energy of Impacts—Related to potential internal damage.
- Impact Amplitude Average—Related to potential internal damage.
- Background Energy Average—Defines normal activity to which impacting activity can be baselined.
- Modified Amplitude Probability Distribution (MAPD) Slope—Used to detect impacting and distorted signals. Slope indicates randomness, periodicity, or a combination of influences.

The following additional acoustic parameters were also obtained:

- Overall amplitude average.
- Average time between impacts.
- Frequency of the peak amplitude present in the Envelope PSD.

- Total number of impacts.
- Percent of data blocks with impacting.

The uncertainties of most acoustic parameters were also calculated using classic statistical formulae.

Spectral Parameters

While PSDs were examined visually, spectral parameters were also defined to more easily trend changes in frequency content related to both flow and impacting of check valve internal parts. The root mean squares (RMSs) of the magnitude of the PSDs, over several frequency bandwidths, were extracted and trended as spectral parameters. Six bandwidths were chosen for the Background, Impact, and Ratio PSDs: 0–2 kHz, 2–3 kHz, 3–4 kHz, 4–5 kHz, 5–7 kHz, and 7–10 kHz. Two bandwidths were selected for the Envelope PSD: 30–85 Hz, and 85–155 Hz. Spectral parameters are hereafter referred to as Background, Impact, Ratio, and Envelope RMS bandpass parameters for the RMS values of the Background, Impact, Ratio, and Envelope PSDs, respectively.

- Other Parameters
- Additional parameters, such as system flow rates, pressures, or reactor power level, can be hand-entered into the meter in the field during data collection and trended along with check valve acoustic and spectral parameters for reference purposes.

Trending of data acquisition parameters, such as threshold level, external gain, envelope short-term averaging time, total sample time, and total data blocks, is also possible to allow the analyst to ensure that data acquisition and collection processes were consistently repeated from measurement to measurement.

TEST LOOP EXPERIMENTS

Test Loop Description

Five common check valves of various types and manufacturers, listed in Table 1, were selected for experiments in a 4-in. test loop constructed in the waste-water treatment facility of a fossil-fuel fired power plant. The test loop consisted of a section of 4-in. bypass piping connected to a 10-in. main system header. When necessary, the test loop was isolated from the main header by a gate valve at the test loop inlet and a globe valve at the test loop outlet. The fluid medium was treated river water at ambient temperature that is used for cooling plant components. During testing, water was typically recirculated through a holding tank to the test loop by way of the main header. Test loop flow rate was controlled with a butterfly valve in the main system header. For convenience, chosen valve size was 4-in., 150-lb pressure class for all check valves during these experiments.

Table 1. Check valve manufacturers, model/part numbers, types, and body materials.

Valve manufacturer	Model/part number	Valve type	Body material
Velan	0114C-02TY	Swing check	Carbon steel
Wm. Powell	1561 FE	Swing check	Carbon steel
Anderson Greenwood	CV-1B	Swing check with spring	Stainless steel
Crane/Chapman	123	Tilting disk	Carbon steel
Marlin	A150SSPWR	Dual disk	Stainless steel

Simulation of Progressive Degradation

Component wear was simulated for each valve by replacing original parts, such as hinge pins, with undersized parts having machined wear surfaces. In order to produce trend data in simulation of progressive degradation, three stages of wear were induced and tested in addition to the new condition (baseline) tests, for hinge pins, disk studs, hinge pins and disk studs combined, and stop pins, giving a total of nine progressive trends with at least four points per trend. The dimensions of valve parts used in this testing are listed in Table 2. Additionally, more severe degradation conditions were introduced based on the designs of the different check valves. These severe degradation conditions were (a) disk loose in valve body for the Velan and Crane valves, (b) disk and arm loose in valve body for the Powell valve, (c) spring missing for the Anderson Greenwood and Marlin valves, and (d) stop pin missing for the Marlin valve. A matrix of simulated valve degradations and test conditions is shown in Table 3.

Valve parts were machined to dimensions based on wear limits obtained from nuclear power plant maintenance procedures and discussions with valve manufacturers. It should be mentioned that the wear limits for the valves examined in this study ranged between 0.7 and 10% of original nominal dimension, compared with degradation ranges between 10 and 30% of hinge pin diameter typically used to simulate check valve degradation in flow loop experiments performed by others.

Data Acquisition

The acoustic parameters and PSDs were calculated from signals measured by a single accelerometer, which had been temporarily stud mounted to a mounting pad affixed near a hinge pin location on the valve bodies. Accelerometer signals were sampled at 25 kHz for a block size of approximately 64K points, corresponding to a 2.5-s sample size. When sampling was complete, acoustic parameters, PSDs, and spectral parameters were calculated for the 64K point data block. For impact detection, a threshold level of 2.5 times the mean was used to define impacts. This procedure was then repeated for each additional 64K point data block. Typically, 50 data blocks, corresponding to 125 seconds of data, were analyzed per complete measurement. Using this envelope impact detection methodology, 50–60% of real time data can be analyzed by the meter (Figure 1). For example, sampling and computations typically required 200 to 250 s for each 125 s of actual data. Computation time increased somewhat if MAPD slopes were computed, allowing analysis of approximately 35–40% of real time data.

Calculations were performed by the data collector, and results were transferred to a personal computer, via an RS232 interface, where they could be trended and more thoroughly analyzed in a comprehensive database management and display system.

TREND PARAMETER EFFECTIVENESS

Acoustic and spectral parameter values, such as impact rate and RMS bandpass amplitudes, are typically expected to exhibit increasing trends as check valve condition worsens. A qualitative review of all test data obtained during these experiments was performed in order to assess each parameter's effectiveness in identifying progressive check valve degradations, such as worn hinge pins, disk studs, or stop pins. Based on whether the expected increasing trend behavior was demonstrated, the effectiveness of a particular trend parameter was then categorized according to one of the following ratings: not statistically significant (NSS), marginal, fair, or good, as shown in Table 4.

Table 2. Part dimensions and percent degradation.

Valve	Component/condition	Diametral dimension (in.)	Degradation (%)
Velan swing check	Hinge pin (original)	0.738	0
	Hinge pin [1]	0.733	0.7
	Hinge pin [2]	0.728	1.4
	Hinge pin [3]	0.718	2.7
	Disk stud bore (original)	0.812	0
	Disk stud bore [1]	0.802	1.2
	Disk stud bore [2]	0.792	2.5
	Disk stud bore [3]	0.782	3.7
Wm. Powell swing check	Hinge pin (original)	0.437	0
	Hinge pin [1]	0.431	1.4
	Hinge pin [2]	0.425	2.7
	Hinge pin [3]	0.413	5.5
Anderson Greenwood swing check	Hinge pin (original)	0.315	0
	Hinge pin [1]	0.304	3.5
	Hinge pin [2]	0.294	6.7
	Hinge pin [3]	0.284	9.8
Crane/Chapman swing check	Hinge pin (original)	0.603	0
	Hinge pin [1]	0.583	3.3
	Hinge pin [2]	0.563	6.6
	Hinge pin [3]	0.543	10
Marlin dual disk	Hinge pin (original)	0.314	0
	Hinge pin [1]	0.307	2.2
	Hinge pin [2]	0.299	4.7
	Hinge pin [3]	0.292	7.0
	Stop pin (original)	0.314	0
	Stop pin [1]	0.307	2.2
	Stop pin [2]	0.299	4.7
	Stop pin [3]	0.292	7.0

Table 3. Matrix of check valve test conditions.

Condition	Valve					
	Velan	Powell	Anderson Greenwood[a]	Anderson Greenwood[b]	Crane	Marlin
Baseline	X	X	X	X	X	X
Hinge pin (HP) [1]	X	X	X	X	X	X
Hinge pin [2]	X	X	X	X	X	X
Hinge pin [3]	X	X	X	X	X	X
Disk stud (DS) bore [1]	X	—	—	—	—	—
Disk stud bore [2]	X	—	—	—	—	—
Disk stud bore [3]	X	—	—	—	—	—
HP [3] and DS bore [1]	X	—	—	—	—	—
HP [3] and DS bore [2]	X	—	—	—	—	—
HP [3] and DS bore [3]	X	—	—	—	—	—
Missing stop pin	—	—	—	—	—	X
Missing seating surface	—	—	X	X	—	—
Broken/missing spring	—	—	X	X	—	X
Misaligned internals	—	—	—	—	—	—
Disk loose in body	X	—	—	—	X	—
Disk and arm loose in body	—	X	—	—	—	—
Stop pin [1]	—	—	—	—	—	X
Stop pin [2]	—	—	—	—	—	X
Stop pin [3]	—	—	—	—	—	X

X = Completed test.

— = Not tested or N/A.

Numbers [1], [2], and [3] refer to three stages of progressive degradation.

a. Vertical hinge pin orientation.

b. Horizontal hinge pin orientation.

Table 4. Trend parameter effectiveness to detection of progressive and extreme degradations.

	Evaluation	
Trend parameter	Detection of progressive degradation	Detection of an extreme condition
Impact rate	Good	Good
Peak amplitude	NSS[a]	Fair
Background energy average	Marginal	Fair
Impact amplitude average	NSS	Fair
MAPD slope	Fair	Good
Background RMS (0–2 kHz)	NSS	NSS
Background RMS (2–3 kHz)	Fair	Marginal
Background RMS (3–4 kHz)	Fair	Fair
Background RMS (4–5 kHz)	Good	Fair
Background RMS (5–7 kHz)	Good	Good
Background RMS (7–10 kHz)	Fair	Good
Impact RMS (0–2 kHz)	NSS	NSS
Impact RMS (2–3 kHz)	Marginal	Marginal
Impact RMS (3–4 kHz)	Fair	Fair
Impact RMS (4–5 kHz)	Good	Fair
Impact RMS (5–7 kHz)	Good	Fair
Impact RMS (7–10 kHz)	Fair	Fair
Ratio RMS (0–2 kHz)	NSS	NSS
Ratio RMS (2–3 kHz)	NSS	Marginal
Ratio RMS (3–4 kHz)	Marginal	Marginal
Ratio RMS (4–5 kHz)	NSS	Fair
Ratio RMS (5–7 kHz)	NSS	Fair
Ratio RMS (7–10 kHz)	NSS	Fair
Envelope RMS (30–85 Hz)	Fair	Fair
Envelope RMS (85–155 Hz)	Fair	Fair

a. NSS: not statistically significant.

The percent changes in trend parameters between the baseline conditions and the most severely degraded hinge pin, stop pin, disk stud, or combined hinge pin/disk stud conditions, which ranged between 2.7–3.7% degradation for the Velan valve, 5.5% degradation for the Powell valve, 9.8% degradation for the Anderson Greenwood valve, valve, 9.8% degradation for the Anderson Greenwood valve, 10% degradation for the Crane valve, and 7% degradation for the Marlin valve, were compiled and averaged. On the average, impact rates increased approximately 1,042%, and MAPD slopes increased approximately 36% between baseline values and severely worn component values. Impact RMS bandpass amplitudes for ranges between 3 kHz and 10 kHz averaged increases between 144% and 385%, while Envelope RMS bandpass amplitudes for ranges between 30 Hz and 155 Hz averaged increases between 70 and 76%. These results should be qualified, however, since for all of these parameters at least one of the nine progressive degradation experiments exhibited decreasing trend behavior, which reduced averaged values. At this time, decreasing trends are not fully understood and are being given further scrutiny.

Also shown in Table 4 is an evaluation of the effectiveness of the trend parameters applied to the detection of more extreme degradation conditions, such as loose disks or missing components. This evaluation was more difficult, since the behavior of the monitored parameters can increase or decrease depending on the type of extreme condition induced in a check valve. For example, if a loose disk becomes wedged such that it cannot move and flow is obstructed to some degree, trends of impact rates and peak amplitudes would be expected to decrease, while trends of background amplitude averages would be expected to increase. Also, RMS bandpass parameter values can increase or decrease, depending on whether flow becomes obstructed, or remains unobstructed, respectively. Under other conditions where loose parts are present, trends of impact rates and impact peak amplitudes would likely increase.

It should be noted that some parameters, which were rated as not statistically significant (NSS) for the detection of relatively small amounts of hinge pin wear, were quite effective at detecting gross check valve degradations such as a loose disk. Also, past experience has shown that Ratio PSDs can be useful in determining the frequency content associated with impact activity. In these experiments, however, Ratio RMS bandpass parameters were typically found to be NSS. This result may result from impact energy present in Background PSDs below the threshold level. Finally, because flow noise and impact activity excite predominant valve body structural modes, the effectiveness of the Background and Impact RMS bandpass parameters over the selected frequency bandwidths is expected to vary with valve size.

Ideally, parameters used for trending check valve condition should all be rated as "good" in terms of effectiveness. During the course of these experiments the test loop could not be isolated from normal background mechanical noise, which is also the case in nuclear power applications, and some measurements may have been affected by these influences. Also, the valve population was limited to one size, pressure class, and fluid medium during these experiments.

SELECTED RESULTS

Progressive Hinge Pin Degradation

A trend of impact rate measured from a 4-in. Marlin dual disk check valve, with three stages of artificially induced progressive hinge pin wear, is shown in Figure 2. In addition, the impact rate for a fourth stage of degradation, a missing spring, is also shown. Impact rate was observed to form an increasing trend as the percentage of hinge pin wear increased. The percent increase between the baseline impact rate and the third stage of hinge pin wear (7% degraded) was 15%. Removal of the spring allowed further movement of the valve disks and resulted in a further increase in impact activity.

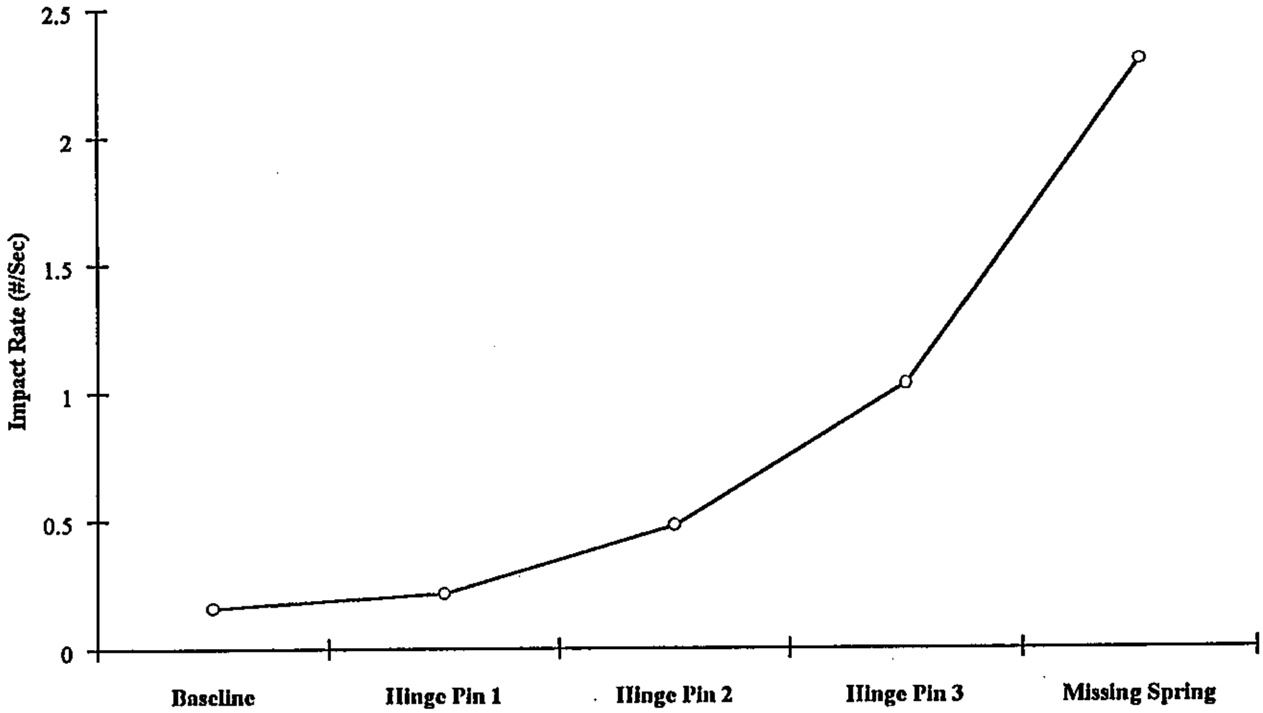

Figure 2. Trend of impact rate from Marlin valve with degrading hinge pin.

Trends of Impact RMS amplitudes over frequency bandwidths of 4–5 kHz, 5–7 kHz, and 7–10 kHz are shown in Figure 3 for the baseline and degraded hinge pin conditions. Percent increases in these trends, between the baseline and the third stage of degradation, were 262%, 216%, and 129%, respectively. Trends of Background RMS amplitudes showed generally increasing behavior as well. Impact PSDs, over a frequency range between 3 and 10 kHz for the baseline and degraded hinge pin conditions, are shown overlaid in Figure 4. Increased energy was clearly evident for the most severely degraded hinge pin case.

Progressive Stop Pin Degradation

Figure 5 shows an increasing trend of both impact rate and MAPD slope for the same 4-in. Marlin dual disk check valve with three stages of artificially induced progressive stop pin wear. The impact rate for an additional stage of degradation, induced by removing the stop pin, is also shown. Both impact rate and MAPD slope formed an increasing trend as the percentage of stop pin wear increased. The percent increase between the baseline trend point and the third stage of stop pin wear (7% degraded) trend point was 1,013% for impact rate and 72% for MAPD slope.

A dramatic decrease in both impact rate and MAPD slope occurred in conjunction with the missing stop pin. This decrease was to be expected because the rattling caused by loose interfaces between the stop pin and the valve body and the impacts from contact between the valve disks and the stop pin were no longer present. This example also showed an extremely good correlation between impact rate and MAPD slope. In this case the random impacting, or rattle, of the stop pin shifted the MAPD average slope towards a less negative value. This behavior was expected with the addition of a second random influence to a random signal, such as flow noise.

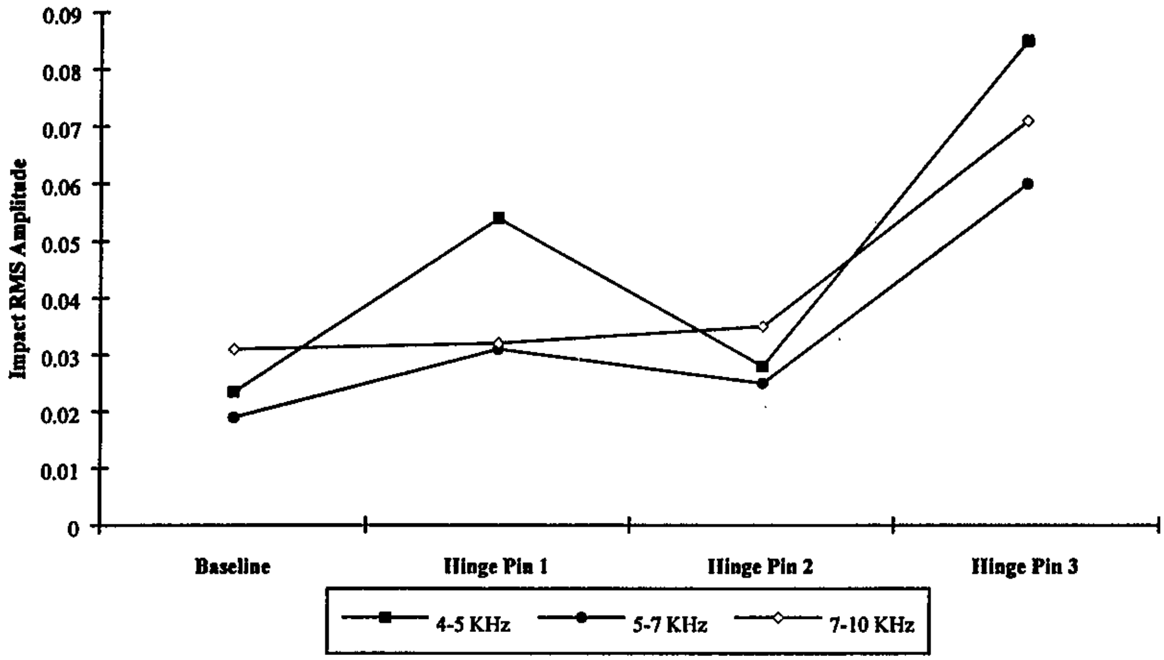

Figure 3. Trend of impact RMS amplitudes from Marlin valve with degrading hinge pin.

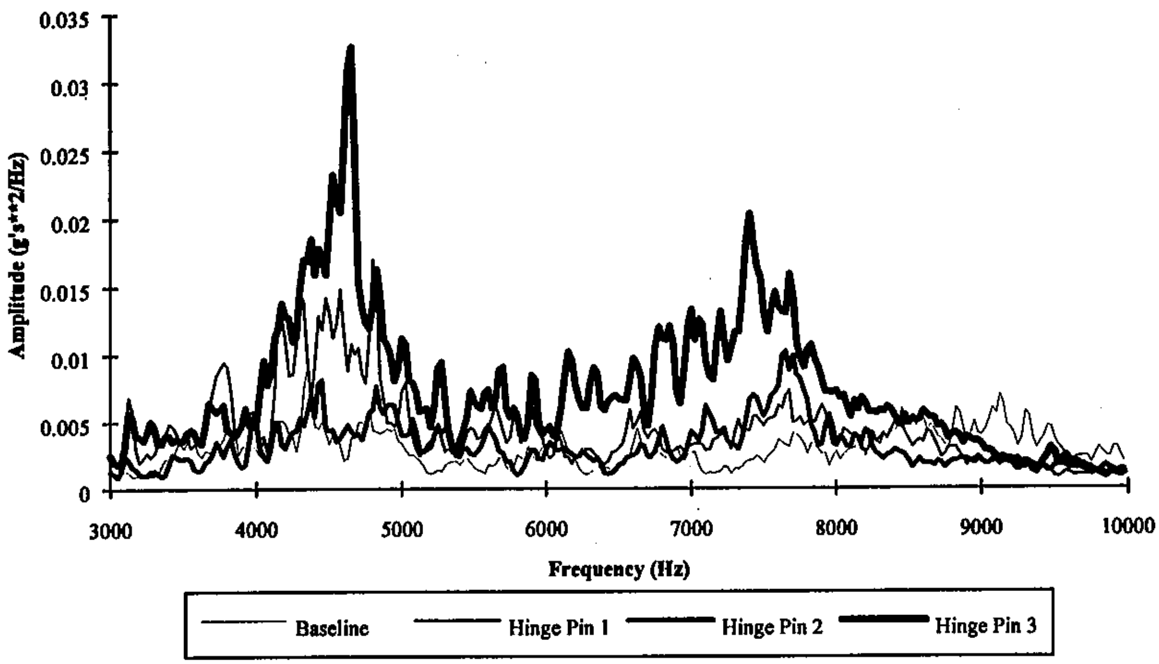

Figure 4. Impact PSDs (3–10 kHz) from Marlin valve with degrading hinge pin.

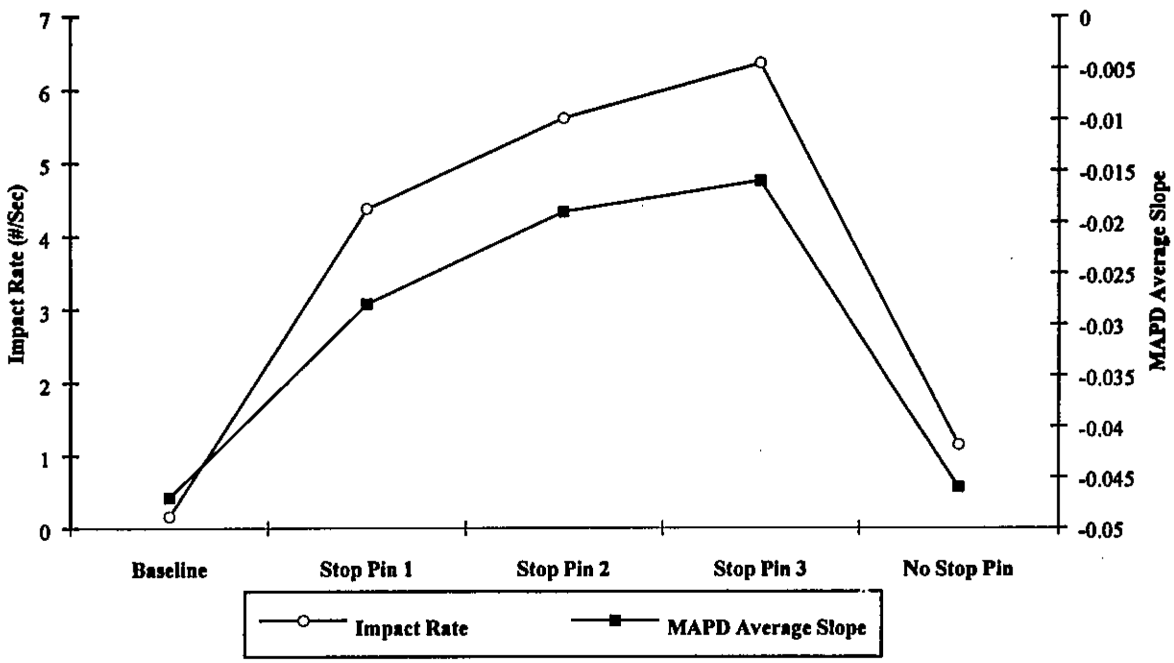

Figure 5. Trend of impact rate and MAPD slope from Marlin valve with degrading stop pin.

Trends of Impact RMS amplitudes over frequency bandwidths of 4–5 kHz, 5–7 kHz, and 7–10 kHz, are shown in Figure 6 for the baseline and degraded stop pin conditions. Generally, increasing behaviors, 57%, 126%, and 126% increases, respectively, were observed in these trends. Background RMS amplitudes exhibited increasing trends as well. Impact PSDs, over a frequency range between 3 and 10 kHz for the baseline and degraded stop pin conditions, are shown overlaid in Figure 7. Increased energy was clearly evident for the most severely degraded stop pin.

Trends of Envelope RMS amplitudes for the same baseline and degraded stop pin conditions over selected frequency bandwidths of 30–85 Hz and 85–155 Hz, are shown in Figure 8. Generally, increasing trends of 274% and 300%, respectively, were observed corresponding to increased impact energy as stop pin clearances increased. Envelope PSDs, over frequency ranges between 0 and 155 Hz for the baseline and degraded stop pin conditions, are shown overlaid in Figure 9. Increasing energy levels were observed for each worsening stop pin condition over the entire 0–155 Hz Envelope PSD frequency band.

Disk and Arm Loose in Valve Body

Figure 10 shows trends of impact rate and impact amplitude average measured from a 4-in. Powell swing check valve with three stages of artificially induced progressive hinge pin wear, and a fourth stage, the disk and arm assembly loose in the valve body. Similar to the Marlin valve, impact rates increased, corresponding to increased hinge pin wear and resulting impacting. A 308% increase in impact rate occurred between the baseline trend point and the third stage of hinge pin wear (6% degraded) trend point. Impact amplitude average, which was rated as NSS in

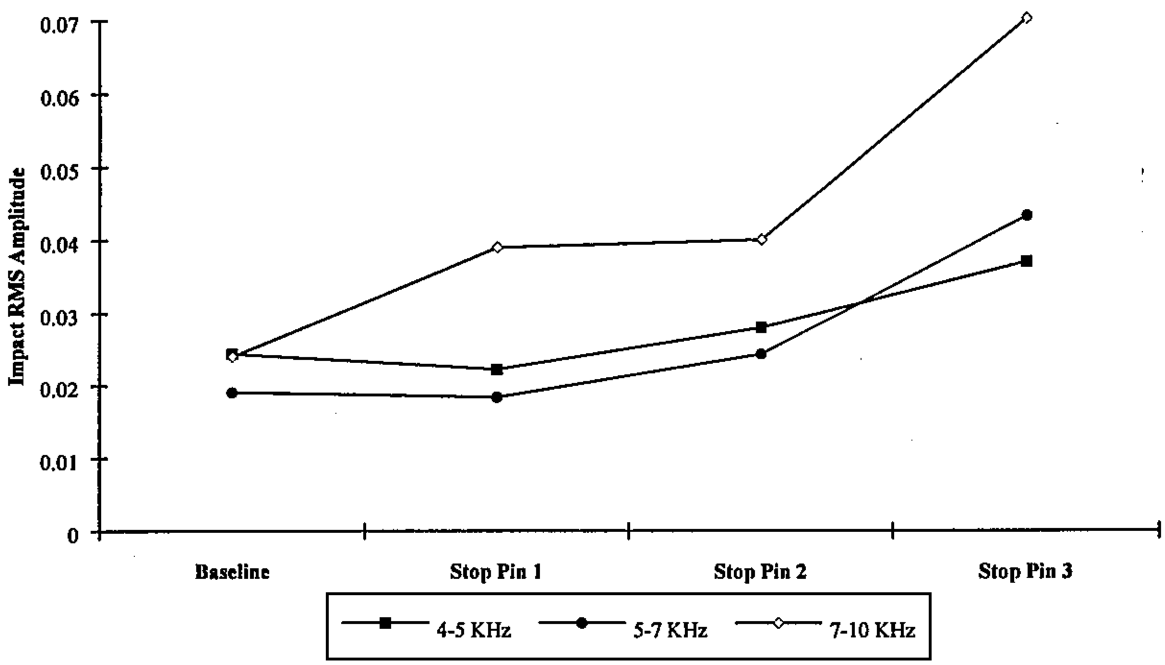

Figure 6. Trend of impact RMS amplitudes from Marlin valve with degrading stop pin.

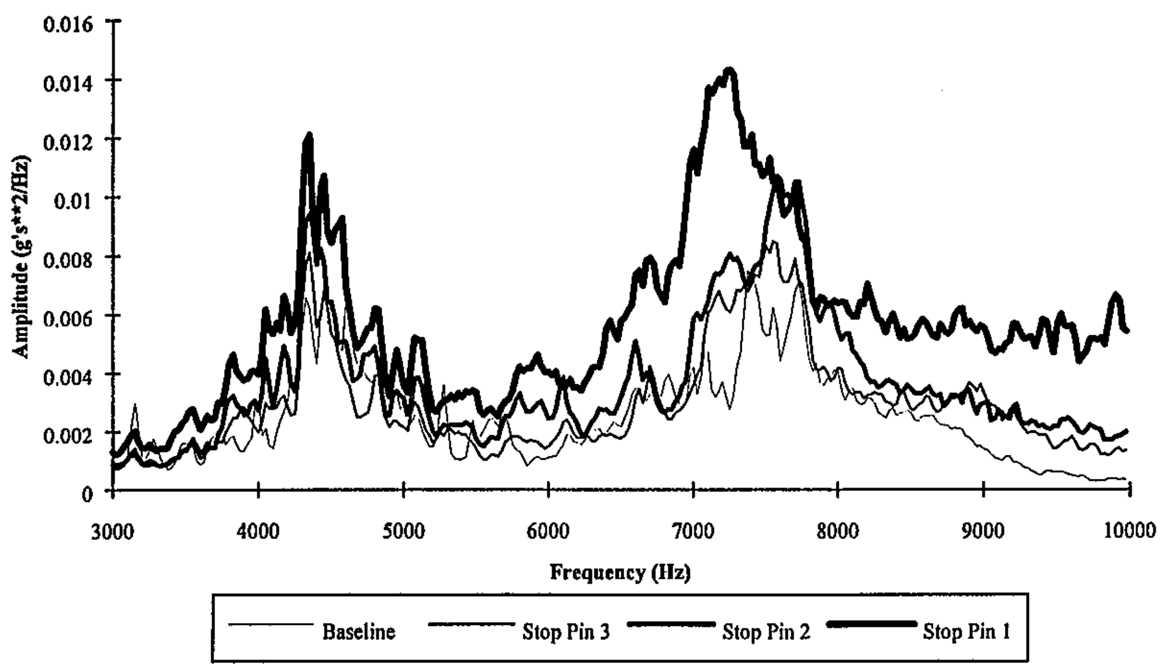

Figure 7. Impact PSDs (3–10 kHz) from Marlin valve with degrading stop pin.

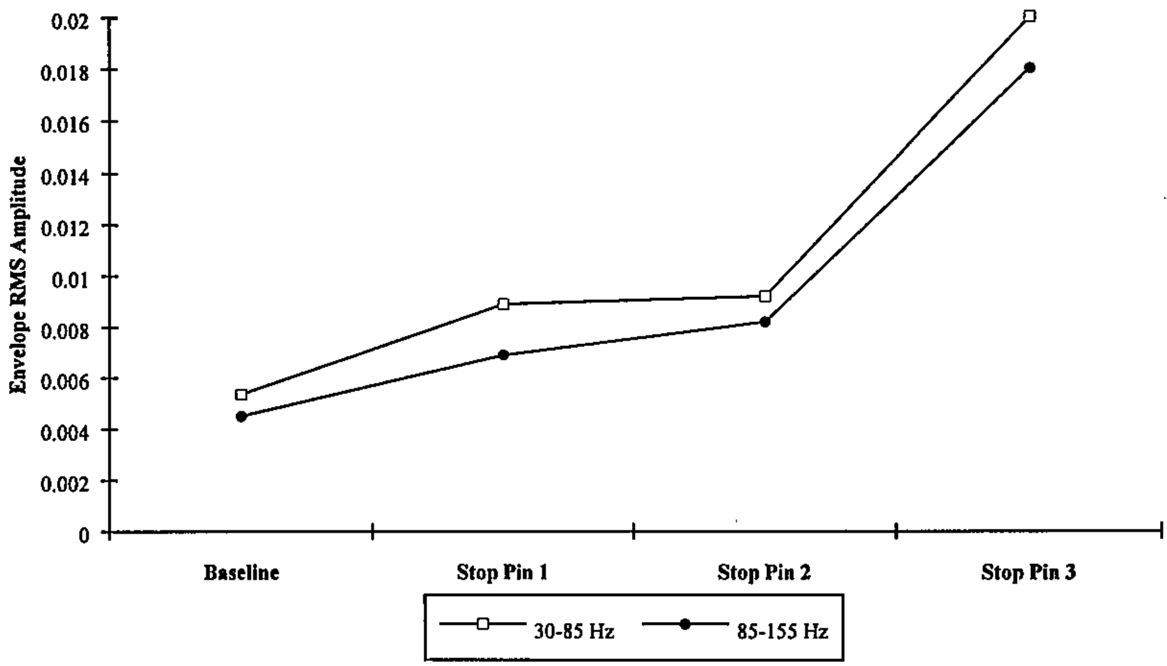

Figure 8. Trend of envelope RMS amplitudes from Marlin valve with degrading stop pin.

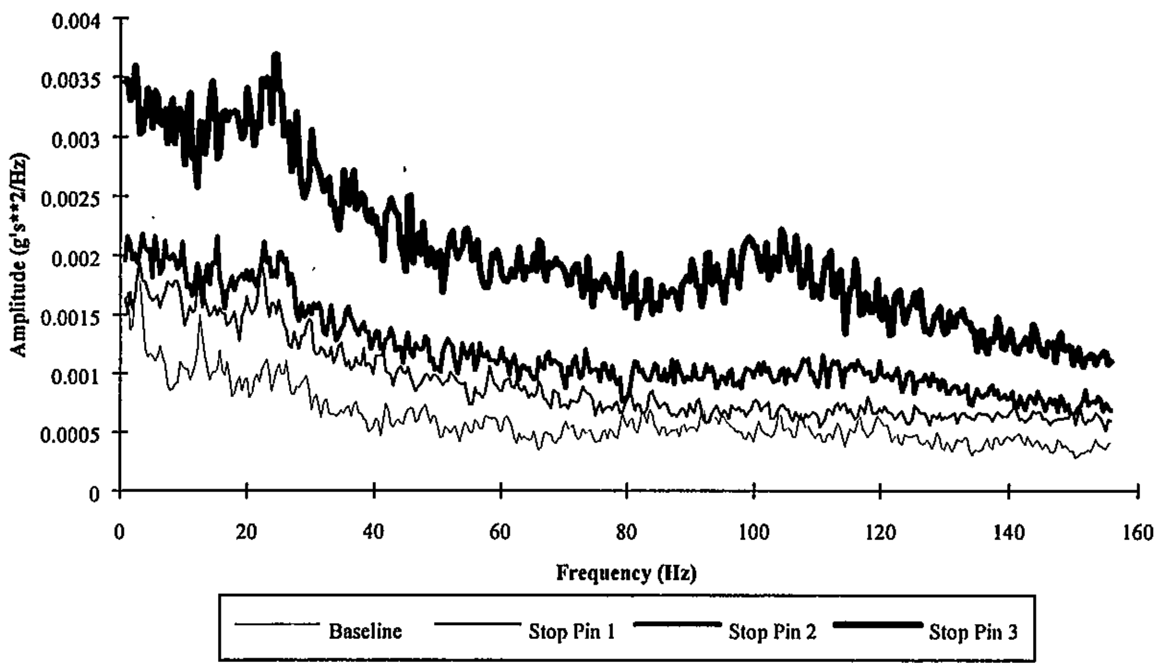

Figure 9. Envelope PSDs for Marlin valve with degrading stop pin.

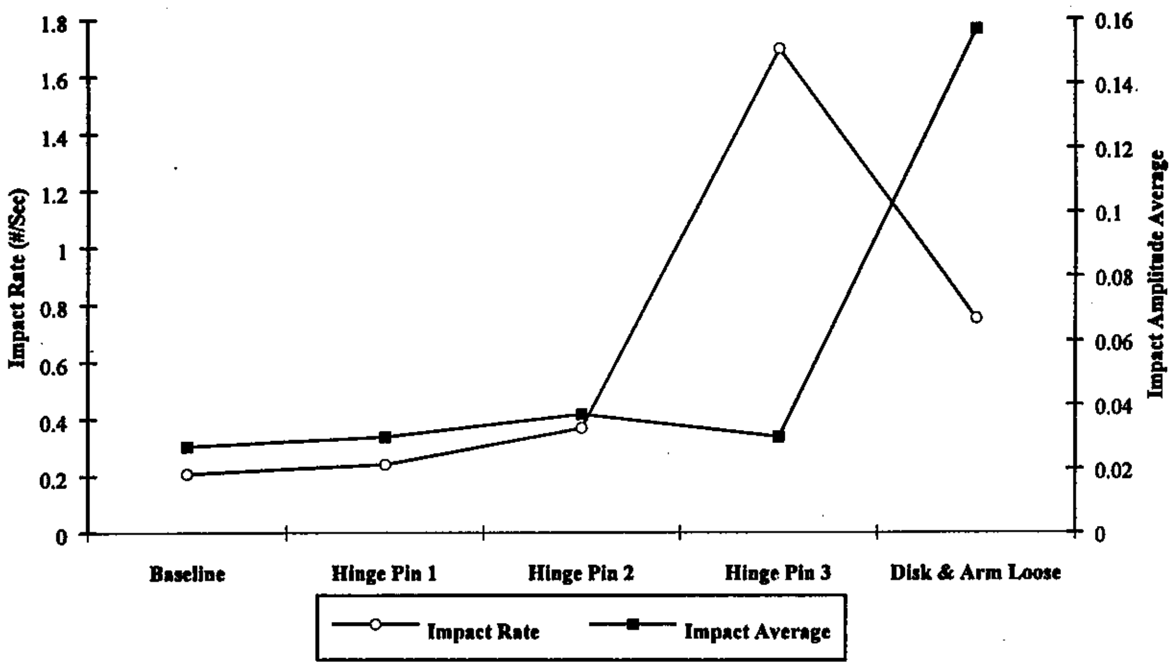

Figure 10. Trends of impact rate and impact amplitude average from Powell valve.

terms of effectively detecting small amounts of hinge pin wear, was quite useful in helping to identify a loose disk and arm assembly. Impact rate decreased abruptly with the "loss" of the disk/arm assembly, while impact amplitude average increased, creating a characteristic "X" at the crossing of the two trends. This result was expected because the more frequent, lower amplitude rattle of the worn hinge pin was replaced by the less frequent, higher amplitude impacting of the disk and arm on the bottom of the valve body.

Trends of impact rate, background average, impact amplitude average, and MAPD average slope are shown in Figure 11 for a 4-in. Velan swing check valve. The first trend point represents a worn hinge pin condition, and the second trend point represents a more severe condition induced by placing the loose disk in the bottom of the valve body. Acoustic parameters related to impacting, namely impact rate, MAPD slope, and impact amplitude average, all decreased with the "loss" of the disk, while the background amplitude average increased. The effect of a loose valve disk, which was causing a partial flow obstruction yet was not impacting, as evidenced by an impact rate equal to zero, could be seen as a decrease in impact energy along with an increase in background energy. Background amplitude average, rated as marginally effective in detecting small amounts of hinge pin wear, proved to be useful in terms of identifying a loose disk which was not impacting.

CONCLUSIONS

By using a relatively inexpensive microprocessor-based vibration data collector with specialized software and nonintrusive sensors, key parameters and PSDs can be calculated from data collected during operating flow and used to characterize changes in check valve condition. The most effective parameter used for detection of check valve degradation was generally found to be impact rate, and in some cases, MAPD slope. Spectral data and RMS bandpass parameters, computed at the same time as the acoustic parameters, also provided key information and helped to verify conclusions. For more severe stages of degradation, such as a loose disk or missing component, RMS bandpass parameters were found to be quite effective.

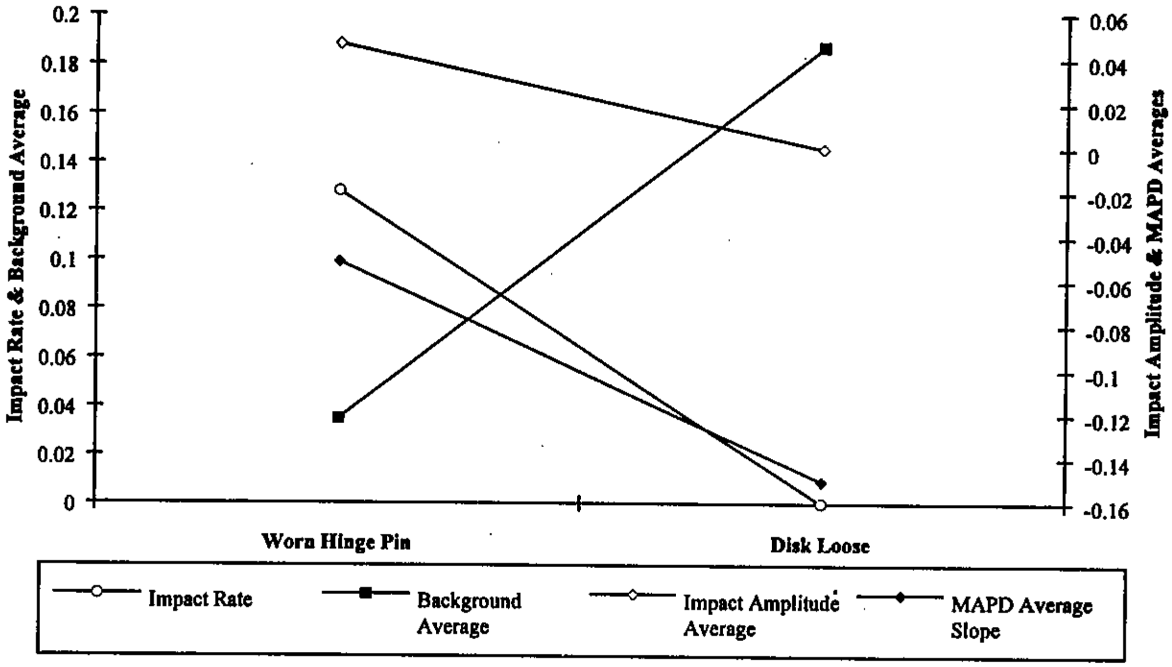

Figure 11. Impact rate, background and impact amplitude averages, and MAPD from Velan Valve.

Using this methodology, check valve can be monitored efficiently and cost-effectively during operating flow conditions without requiring a valve to change its state. More comprehensive testing or dismantling of check valves can be deferred until a degraded condition has been evidenced by increasing trends or significant changes in spectral data. The monitoring should serve to reduce costs by focusing attention on degrading valves, which should in turn help in reducing check valve failures.

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The 1994 Symposium on Valve and Pump Testing, jointly sponsored by the Board of Nuclear Codes and Standards of the American Society of Mechanical Engineers and by the Nuclear Regulatory Commission, provides a forum for the discussion of current programs and methods for inservice testing and motor-operated valve testing at nuclear power plants. The symposium also provides an opportunity to discuss the need to improve that testing in order to help ensure the reliable performance of pumps and valves. The participation of industry representatives, regulators, and consultants results in the discussion of a broad spectrum of ideas and perspectives regarding the improvement of inservice testing of pumps and valves at nuclear power plants.

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