July 6, 1979

EVALUATION OF LICENSEE'S COMPLIANCE
WITH THE NRC ORDER DATED MAY 16, 1979
TOLEDO EDISON COMPANY AND
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
DAVIS-BESSE NUCLEAR POWER STATION, UNIT No. 1
DOCKET NO. 50-346

INTRODUCTION

By Order dated May 16, 1979, (the Order) the Toledo Edison Company and the Cleveland Electric Illuminating Company (TECO or the licensee) were directed by the NRC to take certain actions with respect to Davis-Besse Nuclear Power Station, Unit 1 (DB-1). Prior to this Order and as a result of a preliminary review of the Three Mile Island, Unit No. 2 (TMI-2) accident, the NRC staff initially identified several human errors that contributed significantly to the severity of the event. All holders of operating licenses were subsequently instructed to take a number of immediate actions to avoid repetition of these errors, in accordance with bulletins issued by the Commission's Office of Inspection and Enforcement (IE). Subsequently, an additional bulletin was issued by IE which instructed holders of operating licenses for Babcock & Wilcox (B&W) designed reactors to take further actions, including immediate changes to decrease the reactor high pressure trip point and increase the pressurizer power-operated relief valve (PORV) setting.*

*[IE Bulletins Nos. 79-05 (April 1, 1979), 79-05A (April 5, 1979), and 79-05B (April 21, 1979) apply to all B&W facilities.]

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ENCLOSURE 2

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The NRC staff identified certain other safety concerns that warranted additional short-term design and procedural changes at operating facilities having B&W designed reactors. Those were identified as items (a) through (e) on page 1-7 of the "Office of Nuclear Reactor Regulation Status Report to the Commission" dated April 25, 1979. After a series of discussions between the NRC staff and the licensee concerning possible design modifications and changes in operating procedures, the licensee agreed, in letters dated April 27, 1979 and May 4, 1979, to perform promptly certain actions. The Commission found that operation of the plant should not be resumed until the actions described in Items (a) through (g) of paragraph (1) of Section IV of the Order are satisfactorily completed.

Our evaluation of the licensee's compliance with items (a) through (g) of paragraph (1) of Section IV of the Order is given below. In performing this evaluation we have utilized additional information provided by the licensee in letters dated May 11, 18, 19, 22 (2), 23 (2), 26 (2), 29 and June 15 (2), 18, 21, 23 and 25, 1979 and numerous discussions with the licensee's staff. Confirmation of design and procedural changes was made by members of the NRC staff at the DB-1 site. An audit of the training and performance of the DB-1 reactor operators was also performed by the NRC staff to assure that the design and procedural changes were understood and were being correctly implemented by the operators.

EVALUATION

Item (a)

It was ordered that the licensee take the following action:

> "Review all aspects of the safety grade auxiliary feedwater system to further upgrade components for added reliability and performance. Present modifications will include the addition of dynamic braking on the auxiliary feedpump turbine speed changer and provision of means for control room verification of the auxiliary feedwater flow to the steam generators. This means of verification will be provided for one steam generator prior to startup from the present maintenance outage and for the other steam generator as soon as vendor-supplied equipment is available (estimated date is June 1, 1979). In addition, the licensees will review and verify the adequacy of the auxiliary feedwater system capacity."

The auxiliary feedwater (AFW) system at DB-1 consists of two safety-grade AFW pumps capable of being actuated and controlled by safety-grade signals that ensure the availability of feedwater to at least one steam generator, under the assumed conditions of a single failure. In addition, the capability to manually actuate and control AFW is available in the control room. The sources of water include two condensate storage tanks (CST), the service water system and the fire protection system. The CSTs provide the normal supply (non-safety-grade) and the service water system is used as a backup safety-grade supply.

A low level in either CST is alarmed to the operator and a continuous level is displayed inside the control room. Low pressure switches on the AFW pump suction provide safety-grade signals to automatically shift suction for the pump from the CSTs to the backup service water supply. Additionally, the operator could also manually transfer the AFW suction to the fire water storage tank (FWST) in the fire protection system.

Both steam-driven auxiliary feedwater pump turbines at DB-1 are provided with a governor used for variable pump speed control. The governor is equipped with a small DC motor which changes the speed setpoint on the turbine control valve, thereby controlling steam flow which regulates the turbine and pump speed. This DC motor receives "raise-and-lower" pulses from the safety-grade steam generator level control system or the manual control switches (located in the control room), which change the turbine speed as required. Pulse length is automatically increased the further steam generator level deviates from its setpoint. These changes in pump speed alter the AFW flow and thus control the water level in the steam generators.

A "dynamic brake" feature has been added, which consists of a resistor and electrical contacts in parallel with the windings of the DC motor. When the control pulse is terminated, the braking resistor is placed in parallel with the motor windings, causing rapid dissipation of the energy associated with the motor momentum (thus reducing the amount of motor coast). This, in turn, reduces the amount of pump speed overshoot, thereby allowing fewer speed changes to match the AFW flow rate to the steaming rate of the steam generators.

The licensee has also added flow rate indication for both steam generator AFW inlet lines. Each inlet line has a pipe-mounted ultrasonic flow transducer and signal conditioner. These are located in the auxiliary building and are accessible during normal plant operations. The signal conditioners provide outputs both locally and in the control room on the AFW pump section of the main control console. Each device is designed to provide flow rate indication to each steam generator from 0 to 1000 gpm. The systems are powered from 120 VAC, 60 Hz buses which are fed by redundant non-Class IE station inverters. Functional testing of the installed auxiliary feedwater flow rate indication is to be conducted in conjunction with the functional testing of the dynamic braking modification of AFW pump turbine controls. The staff concludes that the dynamic brake and AFW flow rate indication modifications are acceptable contingent upon successful testing prior to restart.

We have reviewed the piping and instrumentation diagrams and have determined that no active failure of a mechanical component, such as a pump or valve, would preclude obtaining the required AFW flow rate. The licensee has previously performed tests of the manual and automatic level control system. The test results showed that the control system functioned as designed to control steam generator level. Verification of acceptable flow capacity for each of the two AFW pumps was based upon recorded steam generator level changes following a previous reactor trip. These data showed that each pump exceeded the design flow rate of 800 gpm at a steam generator pressure of 1050 psig. (The 800 gpm is the flow rate delivered to the steam generators and does not include the approximately 250 gpm recirculation flow rate.)

Additional information submitted by the licensee (letter from Lowell E. Roe (TECO) to Mr. Robert W. Reid (NRC) dated May 23, 1979) shows that a total minimum flow, to one or both steam generators, of 550 gpm is required to support the accident analyses. Based on these data and analyses, and the agreement by the licensee to perform checkout testing of the dynamic braking and flow rate indication modifications prior to restart, we conclude that adequate assurance exists that the AFW system will deliver the required flow rate upon demand.

By letter (Lowell E. Roe (TECO) to Mr. Robert W. Reid (NRC) dated May 23, 1979), the licensee provided results of a review of the operating history of the AFW system at DB-1. The largest number of failures* occurred during the initial operating and debugging phase of the facility. Fourteen (14) of the seventeen (17) reported failures occurred prior to January, 1978. Subsequent to implementing system design changes as a result of several of these failures, the systems failure rate has been reduced and its reliability enhanced. There were 3 failures of AFW system components from January 1978 to May 1979. (There were a total of 65 actuations of the AFW system in this time period.) Three different components in the AFW system were involved in these three failures: (1) the speed control circuit for #1 AFW pump turbine, (2) a faulty limit switch on an AFW discharge valve, and (3) two sticky AFW pump turbine steam supply valves. In each case, the licensee performed corrective actions.

*[For the purpose of demonstrating improvement in the performance of the AFW system, the licensee has defined a failure of the AFW system to be any event for which at least one train of the AFW system is not delivering design flow to a steam generator.]

A later letter (Lowell E. Roe (TECO) to Mr. Robert W. Reid (NRC) dated June 29, 1979) addressed a series of pressure switch failures which were discovered on May 21, 1979, and which affected both AFW trains. An evaluation of these failures by the licensee concluded that both trains would have automatically actuated if required, but that one train would not have shifted automatically to the service water supply. The NRC staff has discussed these failures with TECO and has requested that an improved surveillance program for these pressure switches be initiated to determine the cause of the failures and the optimum calibration interval. The licensee has agreed to an increased frequency of switch calibration. In addition, the licensee has made procedural changes, requested by the staff, to instruct the operator to manually shift to the alternate supply of water for the AFW pumps, when the CST level drops to three feet (if automatic switchover has not occurred). This procedure provides greater assurance that, even with failures of this nature, the AFW system is available during the longer term. More recently (July 5, 1979), the NRC staff was verbally informed by TECO (Mr. G. Novak) of a valve malfunction which took place in an AFW system pump discharge line on July 4, 1979. The cause of the valve failure (failed closed) was apparently due to an electrical malfunction. TECO stated that they would request the motor vendor to examine the failed motor to determine the cause of the malfunction. The IE site inspector has been requested to follow this evaluation and to determine the need for further study and corrective action if necessary. The licensee has noted that manual capability (local handwheel) to open the valve existed at the time of the failure and that the redundant AFW train was available.

With regard to the operating history of the AFW system, the staff concludes that the licensee has increased the reliability of the AFW system by implementing appropriate corrective actions and design modifications. With regard to the more recent pressure switch and valve failures, the staff concludes that adequate assurance exists that the causes of the failures are being pursued by the licensee in a timely manner, and that the IE site inspector will follow the need for further corrective action.

In addition, the licensee has revised the administrative procedure pertaining to valve alignment and control. These revisions to AD 1839.02 ("Operation and Control of Locked Valves") provide further assurance that mispositioning of AFW system valves would be detected.

Based on the above evaluation, the NRC staff concludes that the licensee has complied with the requirement of Item (a) of the Order.

Item (b)

It was also ordered that the licensee:

> "Revise operating procedures as necessary to eliminate the option of using the Integrated Control System as a backup means for controlling auxiliary feedwater flow."

As indicated in Item (a), the DB-1 AFW system has been designed as a safety grade system and, as such, is separate from the integrated control system (ICS); however, the licensee has indicated that the AFW system is capable of being switched to the ICS mode for a backup means of control. As currently designed, the AFW system has three operational modes of controlling flow: "ICS control", "auto-essential" and "manual." We requested that the licensee consider a more positive means to assure the continued separability of the ICS control position of the mode selector switches. The licensee agreed (letter from Lowell E. Roe (TECO) to Mr. Robert W. Reid (NRC) dated June 15, 1979) to install a mechanical stop on these switches to further deter use of the ICS control position. The IE site inspector has verified the installation of this mechanical stop.

The licensee has revised SP 1106.06 ("Auxiliary Feedwater System"), which describes procedures for AFW system operation. This procedure specifically prohibits the use of the ICS control position on the mode selector switches. Procedural steps for placing the AFW system in service for plant startup require the operator to place the AFW mode selector switches in the auto-essential position. We have reviewed the revised procedure for AFW switch operation and conclude there is sufficient guidance to prevent use of the AFW system in the ICS mode of control.

Other plant procedures that made reference to the ICS control mode of AFW have been revised by the licensee to no longer authorize that mode of control. The staff has reviewed those procedures and concludes that those revisions are adequate. In addition, the NRC staff audit confirmed that the control room operators are aware that ICS control of AFW is prohibited.

Based on the above evaluation, we conclude that the licensee has complied with the requirements of Item (b) of the Order.

Item(c)

The Order requires that the licensee:

> "Implement a hard-wired control-grade reactor trip that would be actuated on loss of main feedwater and/or turbine trip."

The DB-1 original design did not have a direct reactor trip from a malfunction in the secondary system (loss of main feedwater and/or turbine trip). To obtain an earlier reactor trip (rather than delaying the trip until an operator took action or until a primary system parameter exceeded its trip setpoint), the licensee committed to install a hard-wired, control-grade reactor trip on the loss of all main feedwater and/or on turbine trip (letter from Lowell E. Roe (TECO) to H. Denton (NRC) dated April 27, 1979). The purpose of this anticipatory trip is to minimize the potential for opening of the power-operated relief valve (PORV) and/or the safety valves on the pressurizer. This new circuitry meets this objective by providing a reactor trip during the incipient stage of the related transients (turbine trip and/or loss of main feedwater).

TECO has added control-grade circuitry to DB-1 which is designed to provide an automatic reactor trip when either the main turbine trips or there is a reverse differential pressure of 177 psid across both of the two main feedwater check valves (one check valve is located in the main feedwater discharge piping associated with each steam generator). The main turbine trip is sensed by a normally deenergized auxiliary relay associated with the main turbine generator master trip bus. The power for this bus is provided from a 24 volt DC source, which in turn is provided power (through rectifier circuitry) from a non-Class 1E inverter supplied 120 volt AC distribution panel. A contact from the above auxiliary relay is arranged into a 120 volt AC circuit containing four normally deenergized relays. Power for this 120 volt circuit is provided from a Class 1E inverter supplied distribution panel. The design for these four relays and appropriate associated circuitry conform to Class 1E requirements, including physical independence and provisions for testing. Each of these four relays provide one contact which is arranged in series with one of the four Class 1E undervoltage coils associated with one of the four AC reactor trip circuit breakers (one undervoltage coil associated with each AC reactor trip circuit breaker). When these relays are energized, power to the associated Class 1E undervoltage coils is interrupted so as to produce the desired reactor trip.

As indicated above, differential pressure switches across check valves, located in the main feedwater pump discharge piping, actuate upon sensing a reverse differential pressure across these check valves. Two contacts from these differential pressure switches are arranged into a 125 volt DC circuit, which is provided power from a Class 1E 125 volt distribution panel. This circuit contains two associated DC relays. Two contacts (one contact per relay) associated with these relays are arranged in series. This series contact arrangement is provided in parallel with the contact associated with the main turbine generator master trip bus. The remaining circuitry associated with this trip is identical and common (shared) to that described above for the turbine trip (including power supply identification).

Provisions have been included in the design to manually bypass and to reinstate the reactor trip feature associated with the main turbine generator trip. To supplement this feature, the design includes an annunciator which actuates whenever this reactor trip is bypassed and the reactor power level is above 15 percent. Access to this bypass switch will require a key which is under suitable administrative control. Operator verification of the bypass removal is required by procedure during power escalation. The NRC staff has reviewed these procedures and concludes that sufficient administrative control exists. No bypass features are included in the design for the reactor trip feature associated with the loss of main feedwater circuitry. During normal startup or shutdown, an electric auxiliary pump is used when the steam driven main feedwater pumps are not available.

The licensee has analyzed this additional circuitry with respect to its independence from the existing reactor trip system and to assure that the design and operation of this additional circuitry will neither degrade the reliability of the existing reactor protection system nor create any new adverse safety system interactions. Based on our review of the implementation of the added trip circuitry, with respect to its independence from the existing trip circuitry, we conclude that this addition will not degrade the existing reactor protection system design. In addition, the licensee has satisfactorily completed testing of this trip circuitry.

The licensee has committed to perform a monthly periodic test of the added circuitry to demonstrate its ability to open the AC reactor trip circuit breakers (tripping of the AC reactor trip circuit breakers via the under-voltage trip circuit). We conclude that there is reasonable assurance that the additional circuitry will perform its intended function.

Based on the above evaluation, we conclude that the licensee has complied with the requirements of Item (c) of the Order.

<u>Item(d)</u>

This Item in the Order requires the licensee to:

"Complete analyses for potential small breaks and develop and implement operating instructions to define operator action."

By letter, (Lowell E. Roe (TECO) to H. Denton (NRC) dated April 27, 1979), the licensee agreed to provide the analyses and operating procedures of this requirement.

B&W, the reactor vendor for the DB-1 plant, submitted generic analyses for B&W plants entitled, "Evaluation of Transient Behavior and Small Reactor Coolant Systems Breaks in the 177 Fuel Assembly Plant," and supplements to these analyses (References 1 through 5). Additional information specific to DB-1 was transmitted in References 6 to 8. The transmittal under Reference 6 contains Volume III for the B&W generic study covering raised-loop plants. Reference 7 provides additional analytical results specific to DB-1 with appropriate auxiliary feedwater flow rates. Reference 8 provides additional analytical results for the loss of all main feedwater flow accident with loss of all AFW. This latter analysis demonstrates that capability exists at DB-1 which the operator could use in the unlikely event of a loss of main feedwater and a loss of both safety grade AFW trains. This capability consists of using the combined functions the makeup pumps,* the electric startup auxiliary feedwater pump and the PORV to achieve depressurization (only if necessary). We requested that the availability of this option be incorporated in procedures at DB-1. The NRC staff will review these procedural changes prior to startup.

*At DB-1, the makeup pumps are separate from the HPI pumps.

By letter, (Lowell E. Roe (TECO) to Mr. Robert W. Reid (NRC) dated May 22, 1979), TECO referenced the analyses as appropriate for DB-1. The staff evaluation of the B&W generic study has been completed and the results of the evaluation will be issued as a NUREG report in July 1979. A principal finding of our review of the DB-1 submittals and the generic study is a reconfirmation that loss-of-coolant accident (LOCA) analyses of breaks at the lower end of the small breaks spectrum (smaller than 0.04 ft.^{2}) demonstrate that a combination of heat removal by the steam generators, high pressure injection (HPI) system and through the break ensure adequate core cooling. The AFW system used to remove heat through the steam generators has been modified to enhance its reliability as discussed in Item (a).

Uncovering of the reactor core is not predicted for breaks at this end of the small break spectrum with these features available, therefore, cladding temperatures do not rise significantly above pre-reactor trip temperatures (less than 800°F), and remain well within the 10 CFR 50.46 limit of 2200°F. The ability to remove heat via the steam generators has always been recognized to be an important consideration when analyzing very small breaks. The licensee demonstrated that permanent loss of main feedwater and loss of AFW for the first 20 minutes of a small LOCA will not result in uncovering the reactor core. However, when AFW is delayed beyond this time, a positive reliance on AFW actuation exists as a result of the relatively low (1600 psig) HPI system shutoff head for DB-1. Thus permanent loss of both main and auxiliary feedwater could result in uncovering the core and fuel damage for the facility because of the unavailability of the high pressure injection pumps. Makeup pump and startup feedwater pump actuation, as discussed in the analysis of Reference 8 for the loss of feedwater accident with permanent loss of AFW, are considered potentially capable of maintaining the vessel mixture above the core for a small break, but this scenario was not confirmed in the small break analyses. The licensee's position is that such analyses are unwarranted in light of the safety-grade design of the AFW system. Since the additional heat removal and coolant makeup capability does exist at DB-1, we requested that the procedures identify the availability of this option. Implementation of this procedural change will be verified by the staff prior to restart. While the staff recognizes that the AFW system is safety-grade, we also note that the licensee has agreed to continue to review performance of the AFW system for assurance of reliability and performance. Consistent with this long-term agreement, we will require that the licensee modify the plant to provide the greater degree of diversity offered by a 100% capacity motor-operated AFW pump, or an alternative acceptable to the staff.

Another aspect of the analytical studies conducted was an assessment of the effect of recent design changes on the lift frequency of pressurizer safety and relief valves. The design changes included: (1) a change in the setpoint of the PORV from 2255 psig to 2400 psig, (2) a change in the high pressure reactor trip setpoint from 2355 psig to 2300 psig, and (3) the installation of anticipatory reactor trips on turbine trip and/or loss of main feedwater. In the past, during turbine trip and loss of feedwater transients, the PORV was lifted. With the new design, these transients do not result in lifting of this valve. However, lifting of both PORV and safety valves might occur in the cases of rod withdrawal or inadvertant boron dilution transients, using the normally conservative assumptions presented in Chapter 15 of the Final Safety Analysis Report (FSAR). The above design changes did not affect the lift frequency of the valves for these Chapter 15 safety analyses.

Based on our review of the analyses presented by B&W, the staff has determined that a loss of all main feedwater with (1) an isolated PORV (closed block valve), but safety valves opening and closing as designed, or (2) a stuck open PORV consequentially does not result in uncovering the reactor core, provided AFW pumps are initiated within 20 minutes. It is also concluded, that in the event of a loss of all AFW for either case, covering of the core would be sustained to long-term cooling by operator actions described in the analysis of Reference 8. These actions consist of starting at least one of the two makeup pumps, starting the startup feedwater pump, and opening the PORV (only if needed).

Based on the consequences calculated for small break LOCAs and loss of all main feedwater events, and taking into account the expected reliability of the AFW and HPI systems for DB-1, we conclude that the licensee has complied with the analyses portion of Item (d) of the Order.

To support long-term operation of the facility, requirements will be developed for additional and more detailed analyses of loss of feedwater and other anticipated transients. More detailed analyses of small break LOCA events are also needed for this purpose. Accordingly, the licensee will be required to provide the analyses discussed in Sections 8.4.1 and 8.4.2 of the recent NRC "Staff Report of the Generic Assessment of Feedwater Transients in Pressurized Water Reactors Designed by the Babcock and Wilcox Company" (NUREG 0560). Further details on these analyses and their applicability to other PWRs and BWRs will be specified by the staff in the near future. In addition, to assist the staff in developing more detailed guidance on design requirements of relief and safety valve reliability during anticipated transients, as discussed in Section 8.4.6 of NUREG 0560, the licensee will be required to provide analyses of the lift frequency and the mechanical reliability of the pressurizer relief and safety valves of the DB-1 facility.

The B&W analyses show that some operator actions, both immediate and followup, are required under certain circumstances for a small break accident. Immediate operator actions are defined as those actions, committed to memory by the operators, which must be carried out as soon as the problem is diagnosed. Followup actions require operators to consult and follow steps in written and approved procedures. These procedures must always be readily available in the control room for the operators' use. Guidelines were developed by B&W to assist the operating B&W facilities to develop emergency procedures for the small break accident.

The "Operating Guidelines for Small Breaks" were issued by B&W on May 5, 1979 and reviewed by the NRC staff. Revisions recommended by the staff were incorporated in the guidelines.* In addition, by letter, the licensee submitted supplemental guidelines (Lowell E. Roe (TECO) to Mr. Robert W. Reid (NRC) dated May 22, 1979). In response to these guidelines, the licensee made substantial revisions to EP 1202.06 ("Loss of Reactor Coolant and Reactor Coolant Pressure"), EP 1202.14 ("Loss of Reactor Coolant Flow/RCP Trip"), and EP 1202.26 ("Loss of Steam Generator Feed"). These emergency procedures define the required operator action in response to a spectrum of accidents including a LOCA in conjunction with various equipment availability and failures.

The procedure dealing with loss of reactor coolant (EP 1202.06) is divided into three sections. The first section deals with small reactor coolant system leaks within the capacity of the makeup pumps and assumes the reactor does not automatically trip. The second section assumes a small break within the capacity of the HPI system and a situation where the SFAS** and reactor trips may or may not automatically occur. This section incorporates the B&W small break guidance and provides for operator actions in the event other

*[Letter from J. Taylor (B&W) to Z. Rosztoczy (NRC) dated May 16, 1979]

**[The safety features actuation system (SFAS) monitors variables to detect loss of reactor coolant system boundary integrity. Upon detection of "out-of-limit" conditions of these variables, the system initiates various actions, depending upon the location and severity of the "out-of-limit" conditions measured. These actions can include: initiation of emergency core cooling (ECC), which consists of high pressure injection (HPI) and low pressure injection (LPI); containment vessel cooling and isolation; containment vessel spray systems; and starting of the emergency diesel generators.]

systems (such as reactor coolant pumps) do not operate as expected. The third section of this procedure deals with a pipe rupture well in excess of the capability of the makeup and/or HPI pumps (a large break in which the system depressurizes to the point of low pressure injection). Automatic reactor trip and SFAS actuation are assumed. In all cases dealing with a small break, the operator actions are aimed at achieving a safe cold shutdown in accordance with the normal cooldown procedure.

As indicated above, procedures provide guidance to the operators for dealing with small breaks in the event of a degraded condition (such as loss of reactor coolant pumps). If the reactor coolant pumps are inoperable, the operator is directed to establish and verify natural circulation. Procedural steps to restore reactor coolant pump operation, once a pump becomes available, are provided. In the event natural circulation cannot be established and a reactor coolant pump cannot be restarted and plant pressure reaches 2300 psig, the operator is provided procedural steps to relieve the heat energy via the PORV. (Additional relief capacity is provided via the code safety valves if the PORV is inoperable).

In the event that normal feedwater is lost to the steam generators, auxiliary feedwater is automatically initiated via the safety-grade AFW system. EP 1202.26 provides operator guidance in this event. With SFAS actuation, steam generator level is automatically maintained at 96 inches on the startup range to assure adequate heat removal during the small break event.

For all cases in which HPI is manually or automatically initiated, the operators are specifically instructed to maintain maximum HPI flow unless one of the two following criteria is met:

(1) Low pressure injection has been operating for greater than 20 minutes with flow rates in excess of 1000 gallons per minute per train, or

(2) All hot and cold leg temperatures are at least 50 degrees below the saturation temperature for the existing reactor coolant system pressure. If the 50 degrees subcooling cannot be maintained after high pressure injection cutoff, the high pressure injection shall be reactuated.

This requirement to determine and maintain 50°F subcooling has been incorporated into EP 1202.06 ("Loss of Reactor Coolant and Reactor Coolant Pressure") and EP 1202.24 ("Steam Supply System Rupture"). The procedures also provide instructions to the operators to check alternate instrumentation channels to confirm key parameter readings, such as the degree of subcooling. Accordingly, the use of core exit thermocouples as alternate temperature indicators is addressed in the procedures. Under degraded cooling conditions (such as a LOCA), the pressure-temperature limits considered in the Technical Specifications are not applicable to the ensuing depressurization and cooldown because these limits were developed for normal and upset operating conditions only. Density differences between the downcomer and reactor core will cause recirculation flow between the core exit and downcomer via the vent valves.

Mixing of the hot core exit water with the cold HPI water (or makeup water) will provide sufficiently warm vessel temperatures to preclude any significant thermal shock effects to the vessel. Subsequent restoration of AFW would depressurize the reactor coolant system to below 600 psig where pressure vessel integrity is assured for any reasonable thermal transients that might subsequently occur. B&W has agreed to provide a detailed thermal-mechanical generic report on the behavior of vessel materials for those extreme conditions.

The "Loss of Reactor Coolant and Reactor Coolant Pressure" procedure was reviewed by the NRC staff to determine its conformance with the B&W guidelines. Comments generated as a result of this review were incorporated in a further revision to the proced [illegible] mber of the NRC staff walked through this emergency procedure in the Davis-Besse control room. The procedure was judged to provide adequate guidance to the operators to cope with a small break LOCA. The instrumentation necessary to diagnose the break, the indications and controls required by the action statements, and the administrative controls which prevent unacceptable limits from being exceeded are readily available to the operators. We conclude that the operators should be able to use this procedure to bring the plant to a safe shutdown condition in the event of a small break accident.

An audit of 9 of the 25 licensed reactor operators and senior reactor operators was conducted by the NRC staff to determine the operators' understanding of the small break accident, including how they are required to diagnose and respond to it. The DB-1 staff has conducted special training sessions for the operators on the concept of and use of Emergency Procedure 1202.06. The operators were found to have sufficient knowledge of the small break phenomenon and the general requirements of the emergency procedure, although some deficiences were identified which were primarily due to the operators' lack of familiarity with the recently revised procedure. All operators will receive additional training on EP 1202.06 and a facility administered audit prior to assuming licensed duties during power operation.

The audit of the operators also included questioning about the TMI-2 accident and the resulting design changes made at DB-1. The discussions covered the initiating events of the incident, the response of the plant to the simultaneous loss of feedwater and small break LOCA (PORV stuck open), and operator actions that were taken during the course of the incident. In addition, similarities and differences between the TMI-2 accident and the DB-1 incident of September 24, 1977 were discussed. We found their level of understanding sufficient to be able to respond to a similar situation if it happened at DB-1. We also conclude that they have adequate knowledge of subcooling and saturated conditions and are able to recognize each condition in the primary coolant system by several methods. The AFW system was also discussed during the audit to determine the operators' ability to assure proper starting and operation of the system during normal conditions, as well as during adverse conditions such as loss of offsite power or loss of main feedwater. The long-term operation of the system was examined to evaluate the operators' ability to use available manual controls and water supplies. The level of understanding was found to be sufficient to assure proper short- and long-term AFW flow to the steam generators.

The licensed reactor operators and senior reactor operators have received training concerning the TMI-2 accident, small break LOCA recognition, design modifications, and procedure changes. The training included formalized classroom sessions and on-shift review of training material and emergency procedure changes. To determine the effectiveness of this training program, a written exam was administrated to all licensed personnel by the licensee. The exam was reviewed and found acceptable by a member of the NRC staff. Individuals scoring less than 90 percent on the exam will receive additional training and will not assume licensed duties until a score of at least 90 percent is attained on an equivalent, but different exam. The NRC staff conducted audits to evaluate the effectiveness of the training program. The results were judged satisfactory with some deficiencies noted to the DB-1 staff. The DB-1 staff will use the results of these audits as well as any generic weaknesses discovered on the written exams in their development of future training and requalification programs. The NRC staff will review all results and records as part of the normal inspection function of the DB-1 requalification program. We conclude that there is adequate assurance that the operators at DB-1 have, and will continue to receive, a sufficient level of training concerning the TMI-2 accident.

Based on the above evaluation, we conclude that the licensee has complied with the requirements of Item (d) of the Order.

Item (e)

The Order requires that:

> "All licensed reactor operators and senior reactor operators will have completed the Three Mile Island Unit No. 2 simulator training at B&W."

The licensee has confirmed that all reactor operators and senior reactor operators have completed the TMI-2 simulator training at B&W as required by the Order. This training consisted of a class discussion of the TMI-2 event and a demonstration of the event on the simulator and how it should have been controlled. The class discussion was about one hour long and the remainder of the four hour session was conducted on the simulator. The TMI-2 event, including operational errors, was demonstrated to each operator. The event was again initiated and the operators were given "hands-on" experience in successfully regaining control of the plant by several methods. Other transients, which resulted in depressurization and saturation conditions, were presented to the operators, in which they maneuvered the plant to a stable, subcooled condition.

The licensee has submitted copies of procedures that were revised as a result of this Order and actions the licensee has taken to preclude the occurrence of an incident similar to that which occurred at TMI-2.* The procedures reviewed by the staff include:

*[As noted on page 16 of this Safety Evaluation, additional and more detailed analyses of loss-of-feedwater transients and other anticipated transients will be done, which could affect these procedures in the long-term.]

EP 1202.01	Load Rejection
EP 1202.02	Station Blackout
EP 1202.03	RCS Overpressure Anticipatory Manual Trip
EP 1202.04	Reactor-Turbine Trip
EP 1202.06	Loss of Reactor Coolant and Reactor Coolant Pressure
EP 1202.14	Loss of RC Flow/RCP Trip
EP 1202.22	High Condenser Pressure
EP 1202.24	Steam Supply System Rupture
EP 1202.26	Loss of Steam Generator Feed
AB 1203.04	Depressurization of the RCS with Safety Grade Equipment
AB 1203.02	Loss of All AC Power
AP 3003.41-.44	High Pressure Injection High Flow Alarm
AP 3003.49-.50	Low Pressure Injection High Flow Alarm
AP 3003.51-.54	High Pressure Injection Low Flow Alarm
AP 3003.59-.60	Low Pressure Injectic.. Low Flow Alarm
SP 1105.16	Steam and Feedwater Rupture Control System Operating Procedure
SP 1106.06	Auxiliary Feedwater System
ST 5071.01	Auxiliary Feedwater System Monthly Test
Special Order No. 20	Additional Guidance for Checking Critical Parameters for Emergency Procedures

The licensee's revised procedures provide additional guidance for the operators when coping with emergency plant conditions. Where appropriate, operators are directed to recheck certain critical plant parameters. Operators are also directed to check alternate instrument channels to confirm readings and reduce the possibility of reliance on faulty or misleading indications.

NRC staff comments on the licensee's procedures have been incorporated into the revised documents. These revisions have been reviewed by the staff and determined to be acceptable. The staff walked through the following procedures with the control room operators: EP 1202.06 ("Loss of Reactor Coolant and Reactor Coolant Pressure"), EP 1202.14 ("Loss of RC Flow/ RCP Trip"), EP 1202.26 ("Loss of Steam Generator Feed"), and SP 1106.06 ("Auxiliary Feedwater System"). Based on this walk through and interviews with the operators, (see the discussion of the NRC staff audit of operators under Item (d)), we conclude that the procedures are functionally adequate and the operator training on their use is satisfactory.

Based on the above evaluation, we conclude that the licensee is in compliance with Item (e) of the Order.

Item (f)

The Order requires that the licensee:

> "Submit a reevaluation of the TECO analysis of the need for automatic or administrative control of steam generator level setpoints during auxiliary feedwater system operation, previously submitted by TECO letter of December 22, 1978, in light of the Three Mile Island No. 2 incident."

By letter, (Lowell E. Roe (TECO) to Mr. Robert W. Reid (NRC) dated May 19, 1979), the licensee provided additional discussion of the steam generator dual level setpoint. The need for this feature is to reduce the potential for loss of pressurizer level indication as a result of overcooling of the primary system for non-LOCA events. The results of a natural circulation test conducted at DB-1 and B&W analyses demonstrate that DB-1 can be operated at a low steam generator level (35 inches on the startup range instrumentation). The high level setpoint (96 inches indicated on the startup range instrumentation) is required since previous small break analyses assumed that auxiliary feedwater was controlled to a steam generator level of 96 inches. Pending incorporation of permanent design modifications to provide the automatic dual setpoint steam generator level control, emergency procedures instruct the operator to manually control the steam generator level at 35 inches for all events requiring AFW unless an SFAS level 2* signal occurs. When the SFAS level 2 signal occurs, the operator is instructed to control the steam generator level at 96 inches by placing the AFW mode selector switch in the auto essential position. This manual provision required no previous change to the design of the AFW control system. The future circuitry modification, to automatically control to 35 inches, will be reviewed by the staff during the long term. TECO has cited Reference 9 to demonstrate that no unreviewed safety issues or detrimental accident consequences would result if the operator failed to manually control the steam generator level at 35 inches. The staff reviewed the information contained in this reference and concluded that additional information was required to verify that the effects of manually controlling the steam generator level at 35 inches is adequate for the DB-1 FSAR Chapter 15 transient and

*[SFAS level 2 - An SFAS level 2 signal is developed when reactor coolant system pressure drops to 1600 psig or containment vessel pressure increases to 4 psig.]

accident analyses, and the more recent B&W small break analyses (Reference 1). By letter, (Lowell E. Roe (TECO) to Mr. Robert W. Reid (NRC) dated June 15, 1979), the licensee stated that the control of the steam generator level at 35 inches has no adverse effect on the DB-1 FSAR analyses, since the peak reactor temperature and pressure following the most severe transients (loss of feedwater, feedwater line breaks, loss of offsite power) occur prior to initiation of the AFW. The results of natural circulation testing conducted at DB-1 support the effectiveness of the 35 inch steam generator control level to maintain natural circulation and remove decay heat for: (1) transients that result in loss of forced circulation (loss of offsite power) and (2) for small breaks (less than 0.01 $ft.^2$) that depressurize slow enough that it is possible to manually control the steam generator level prior to actuation of the SFAS level 2 signal. For small breaks larger than 0.01 $ft.^2$, reduction of the reactor coolant system pressure to SFAS level 2 occurs prior to the steam generator level decreasing to 96 inches. With the steam generator level controlled at 35 inches, the effectiveness of natural circulation is such that there is no small break size that will result in repressurization of the primary system without an SFAS level 2 actuation. The staff has reviewed the information provided by TECO in the referenced documents and concludes that dual level setpoints, with manual control of the steam generator level at 35 inches, are acceptable. Also, the NRC staff has verified that this manual control capability has been previously demonstrated.

The licensee has submitted revised procedures, which the staff has reviewed, that provide requirements for steam generator level control. These procedures include: EP 1202.06 ("Loss of Reactor Coolant and Reactor Coolant Pressure"), EP 1202.14 ("Loss of RC Flow/RCP Trip") and EP 1202.26 ("Loss of Steam Generator Feed"). The NRC staff has verified that these procedures instruct the operator to confirm that the AFW mode selector switches are in the auto-essential position and maintaining steam generator level at 96 inches on the startup range indication in the event SFAS level 2 condition is present.

If a SFAS level 2 condition is not present and an AFW system demand event occurs, steam generator levels will automatically control at 96 inches (since the AFW mode selector switches are in the auto-essential position). The operator is directed to take manual control of steam generator level and maintain level at 35 inches on the startup range indication. If an SFAS Level 2 condition subsequently develops, the operator must return the AFW mode selector switches to the auto-essential position to allow automatic level control at 96 inches. Therefore, the emergency procedures are written to permit manual control of steam generator level after an automatic initiation of AFW only if an SFAS level 2 condition is <u>not</u> present.

If a SFAS level 2 condition is present (or develops), the operator is directed to leave (or return) the AFW mode selector switches in the auto-essential position. In addition, a warning plate has been installed adjacent to the mode selector switch for each AFW train, reminding the operator of the requirement to maintain the switch in the auto-essential position mode if an SFAS level 2 condition is present. The NRC staff has verified the installation of this warning plate. Also, during the audit the NRC staff confirmed that the control room operators are aware of the requirements outlined in the revised procedures and understand the purpose of the warning plate.

Based on the above evaluation, we conclude that the licensee has complied with the requirements of Item (f) of the Order.

Item (g)

The Order requires that the licensee:

> "Submit a review of the previous TECO evaluation of the September 24, 1977 event involving equipment problems and depressurization of the primary system at Davis-Besse 1 in light of the Three Mile Island Unit No. 2 incident."

By letter (Lowell E. Roe (TECO) to Mr. Robert W. Reid (NRC) dated May 18, 1979), the licensee submitted additional discussion of the September 24, 1977 event.

This event was similar in several important areas to the TMI-2 accident. The initiating malfunction was a loss of main feedwater (the same as TMI-2); however, the ensuing trainsient was much less severe than TMI-2 for several significant reasons. The following discussion compares The DB-1 event to the accident at TMI-2. The bases for this comparison are the six human, design and mechanical failures described in IE Bulletin 79-05A (April 5, 1979) which resulted in core damage and radiation releases at the TMI-2 nuclear plant.

1. <u>At the time of the initiating event, loss of feedwater, (at TMI-2) both of the auxiliary feedwater trains were valved out of service</u>.

The DB-1 loss of feedwater (LOFW) event initiated both trains of AFW. However, only one train fed its associated steam generator (SG) due to a malfunction of a turbine governor which kept one of the two AFW pump turbines at a speed insufficient to pump water into its associated SG.

As a result of the DB-1 event, the modifications that have been made include: (1) the AFW pump turbine governors were modified to prevent binding malfunctions; (2) springs were installed in the AFW governor to prevent closure of the governor valve due to vibration; (3) the AFW governor control circuitry relays were replaced (see additional AFW discussions in Item (a)).

2. <u>The pressurizer power-operated relief valve (PORV), which opened during the initial pressure surge (at TMI-2), failed to close when pressure decreased below the actuation level</u>.

During the DB-1 LOFW, the PORV also failed to close, causing loss of coolant and some voiding in the reactor coolant system (RCS). However, the operators recognized the open PORV about 20 minutes into the event (compared with 2 1/2 hours at TMI-2) and responded by closing the PORV block valve and reinitiating high pressure injection (HPI) flow.

The DB-1 unit has been modified to provide the operator with a better status of the position of the PORV. The emergency procedures were also revised and now require the operator to verify that no leak exists at the top of the pressurizer by monitoring the saturation curve and quench tank pressure and level.

3. Following rapid depressurization of the pressurizer (at TMI-2), the pressurizer level indication may have led to erroneous inferences of high level in the RCS. This erroneous high level indication apparently led the operators to prematurely terminate HPI, even through voids existed in the RCS.

For the DB-1 LOFW event, the operator also initially terminated HPI due to a high pressurizer level indication; however, the operator recognized the open PORV at 20 minutes and reinitiated HPI at 49 minutes (after failing to control pressurizer level with a second makeup pump).

DB-1 procedures have been revised and now require that for all cases in which HPI is initiated, maximum HPI flow is to be maintained unless one of two criteria is met. These criteria are addressed in Item (d).

4. Because the containment does not isolate on HPI initiation (at TMI-2), the highly radioactive water from the relief valve discharge was pumped out of containment by the automatic initiation of a transfer pump. This water entered the radioactive waste treatment system in the auxiliary building

where some of it overflowed to the floor. Outgassing from this water and discharge through the auxiliary building ventilation system and filters was the principal source of the offsite release of radioactive noble gases.

Containment isolation at DB-1 occurs at either 1600 psig RCS pressure (HPI initiation) or 4 psig containment vessel pressure. During the DB-1 event, containment isolation signals occurred and the sump was not pumped outside containment as at TMI-2.

5. Subsequently, the HPI system was intermittently operated (at TMI-2) attempting to control RCS inventory losses through the PORV, apparently based on pressurizer level indication. Due to the presence of steam and/or noncondensible voids elsewhere in the RCS, this led to a further reduction in primary coolant inventory.

During the DB-1 event, the operator initially tried to control the pressurizer level decrease with a second make-up pump after closing the PORV block valve. However, after the pressurizer level decreased further he restarted a HPI pump. When the pressurizer level was recovered, he terminated the HPI flow. At this time plant parameters were under control and the plant was brought to a stabilized condition.

As indicated in Part 3 above, DB-1 procedures have been revised to require that for all cases in which HPI is initiated, maximum HPI flow is to be maintained unless one of two criteria is met. These criteria are addressed in Item (c).

6. <u>Tripping of reactor coolant pumps during the course of the transient (at TMI-2), to protect against pump damage due to pump vibration, led to fuel damage since voids in the RCS prevented natural circulation</u>.

   During the DB-1 incident, two RCP's were tripped to reduce system heat input into the RCS. One RCP per loop was maintained in operation throughout the incident.

   The DB-1 emergency operating procedures now require keeping at least one RCP per loop running in the event of a small LOCA.

To summarize Item (g) of the Order, the staff views the September 24, 1977 event at DB-1 to have been similar to the TMI-2 event in several important asp cts. However, significant differences in plant status and operator response contributed n produce a much less severe transient. The staff concludes that satisfactory improvements in both design and emergency procedures have been made since the DB-1 event and, that, the licensee has complied with the requirement of Item (g) of the Order.

<u>CONCLUSION</u>

We conclude that the actions described above fulfill the requirements of our Order of May 16, 1979 in regard to Paragraph (1) of Section IV. The licensee having met the requirements of Paragraph (1) may restart DB-1 as provided by Paragraph (2). Paragraph (3) of Section IV of the Order remains in force until the long term modifications set forth in Section II of the Order are completed and approved by the NRC.

REFERENCES

1. Letter from J. H. Taylor (B&W) to R. J. Mattson (NRC) transmitting report entitled, "Evaluation of Transient Behavior and Small Reactor Cooalnt System Breaks in the 177 Fuel Assembly Plant," dated May 7, 1979.

2. Letter from J. H. Taylor (B&W) to R. J. Mattson (NRC) transmitting revised Appendix 1, "Natural Circulation in B&W Operating Plants (Revision 1)," dated May 8, 1979.

3. Letter from J. H. Taylor (B&W) to R. J. Mattson (NRC) transmitting additional information regarding Appendix 2, "Steam Generator Tube Thermal Stress Evaluation," to report identified in Item 1 above, dated May 10, 1979.

4. Letter from J. H. Taylor (B&W) to R. J. Mattson (NRC), providing an analysis for "Small Break in the Pressurizer (PORV) with no Auxiliary Feedwater and Single Failure of the ECCS," identified as Supplements 1 and 2 to Section 6.0 of report in Item 1, dated May 12, 1979.

5. Letter from J. H. Taylor (B&W) to R. J. Mattson (NRC), providing Supplement 3 to Section 6 of report in Item 1, dated May 24, 1979.

6. Letter from Lowell E. Roe (TECO) to Mr. Robert W. Reid (NRC) dated May 22, 1979, providing Volume III to Reference 1 for the raised loop plant.

7. Letter from Lowell E. Roe (TECO) to Mr. Robert W. Reid (NRC) dated May 23, 1979.

8. Letter from Lowell E. Roe (TECO-Serial No. 517) to Harold R. Denton (ONRR) dated June 15, 1979.

9. Letter from Lowell E. Roe (TECO) to Mr. Robert W. Reid (NRC) dated December 22, 1978.