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April 15, 1988

Mr. A. Bert Davis
Regional Administrator
U.S. Nuclear Regulatory Commission
Region III
799 Roosevelt Road
Glen Ellyn, IL 60137

Subject: LaSalle County Station Unit 2
Response to Confirmatory Action Letter
NRC Docket No. 50-374

Reference: A. B. Davis letter to Cordell Reed dated
March 17, 1988 transmitting CAL-RIII-88-03.

Dear Mr. Davis:

The above referenced Confirmatory Action Letter (CAL) requested that Commonwealth Edison submit a formal report of our findings and conclusions relating to the LaSalle County Unit 2 event of March 9, 1988 in which there was a dual recirculation pump trip and subsequent core performance anomalies. This report responds to the issues listed in the CAL and the subsequent questions submitted by the Augmented Inspection Team (AIT). We would like to express our appreciation for the AIT Team's willingness to work extended hours to expedite their thorough investigation in order to accommodate plant conditions.

This letter and the attachments respond to all issues and questions regarding this event. Attachment A responds to the four items stated in the CAL. Attachment B responds to the list of questions presented at the preliminary exit meeting on March 18, 1988. Attachment C responds to the seven additional questions presented on March 23, 1988. Attachment D responds to the three additional questions presented to us prior to the AIT exit meeting on March 24, 1988.

Please address any questions that you or your staff may have concerning this response to this office.

Very truly yours,

M. S. Turbak

M. S. Turbak
Assistant Licensing Manager

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Attachments: As Stated

Attachment 5

cc: P. Shemanski - NRR

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ATTACHMENT A

COMMONWEALTH EDISON COMPANY RESPONSE TO

THE MARCH 17, 1988, CONFIRMATORY ACTION LETTER (CAL)

1. Perform an evaluation of reactor performance during this event including secondary systems, the reactor protection system, and ATWS systems.

A detailed review of the systems performance was conducted prior to On-Site Review for Unit 2 Startup. All alarms/actuations received indicated as expected for the valving sequence described by the instrument technicians involved.

A summary of the Anticipated Transient Without Scram (ATWS), Reactor Protection System (RPS), and secondary systems performance is included below:

ATWS

The rapid closure of the reference leg isolation valve on Wide Range instrument 2B21-N037BB caused a pressure pulse on the reference leg of all Narrow and Wide range instruments which share the reference leg at that rack. Increasing pressure on the reference leg side will cause the level instrument(s) to indicate low vessel level.

Because the Wide and Narrow range transmitters at the same instrument rack (2H22-P027) feed the Startrec computer, the approximate magnitude of the pulse can be observed in the computer output. When corrected for Startrec calibration error, this signal appears to have a minimum level of approximately -36 to -40 inches. Therefore, only Level 3 (+12.5 inches) actuations would be expected, and possibly some Level 2 (-50 inches) instruments could trip if their setpoints were conservative and/or the pressure pulse was slightly more severe than the pulse at the Wide Range transmitter feeding Startrec.

ATWS Reactor Recirculation (RR) pump trip switches 2B21-N036C and 2B21-N036D are installed at instrument rack 2H22-P027, and share the reference leg with the 2B21-N037BB switch being tested by the Instrument Mechanic (IM) technician. Switch 2B21-N036C is designed to trip the "A" RR pump to OFF by tripping the "3" (high Speed) and "2" (low Speed) breakers (reference electrical schematic 1E-2-4205AB). Switch 2B21-N036D is designed to trip the "B" RR pump to OFF in the same manner (schematic 1E-2-4205AM). Therefore, a spike on the common reference leg of these two instruments could be expected to cause both pumps to trip-off if it were sufficient to trip one. The results are in reasonable agreement with the observed spike.

The other Level 2 functions at the P027 rack would not necessarily be expected since the size of the pulse was marginal for a Level 2 actuation. The Reactor Core Isolation Cooling (RCIC) switch under test would not actuate with its equalizing valve open, so even if the other switch at that rack actuated (2B21-N037DB), a RCIC actuation would not result because both switches are required. No Alternate Rod Insertion (ARI) initiation occurred because only one level transmitter is connected at the rack, and the logic requires more than one level signal. Had the ARI level transmitter at the P027 rack spiked sufficiently to actuate the ARI Level 2 signal, a printout on the process computer from digital point C567 would be expected if the low level signal existed for greater than 1 full second (the duration of the spike was less than 1 second). This point did not print.

The rest of the instruments at the rack are Level 1 or Level 3 functions, or straight pressure instruments which would not be affected by the pulse of less than 60 to 70 inches of water column (inwc) (2.5 psi).

No Level 1 (-129 inches) actuations were experienced or expected, since the magnitude of the spike was not large enough.

RPS

The Level 3 (+12.5 inches) switches at 2H22-P027 actuated as designed. One of these (2B21-N024B) provides the RPS channel B1 low level 1/2 scram. The pressure spike on the instrument reference leg drove the narrow range instruments to read low, indicating a minimum of about 0.0 inches. The RPS B1 Level 3 alarm was received, and the associated 1/2 scram was also received (NOTE: the Hathaway printout shows the 1/2 scram alarm, then 6 milliseconds later the Level 3 alarm. This is due to the relay configuration for the Level 3 alarm having an extra slave relay to provide the alarm. The relay delay causes the indicated time discrepancy). The Level 3 alarm condition cleared approximately 1.2 seconds after it occurred. The 1/2 scram was reset 5.0 seconds after the Level 3 alarm cleared, after stable level indication was observed. These actuations are as expected. No prolonged low level signal existed, and no other RPS channels were affected. Therefore, a full scram was not to be expected.

The other Level 3 indication at the P027 rack was from the Level 3 Automatic Depressurization System (ADS) confirmatory switch 2B21-N038B. This alarm was also received and cleared in the same time frame as the Level 3 RPS alarm, indicating consistent performance of the level switches.

Average Power Range Monitor (APRM) FLUX TRIP

The performance of the RPS in response to APRM trip signals was evaluated in the On-Site Review (LOSR 88-16). That review showed that the only APRM signals exceeding the trip setpoint caused the appropriate 1/2 scram, and then full scram, RPS actuations. The scram went to completion properly, with all rods scramming in to the full in position. No anomalous behavior of the RPS or RPS inputs was noted during the event review.

SECONDARY SYSTEMS PERFORMANCE

RR Pump Logic

The exact cause for the initial inability to start the "A" RR pump during the event on March 9, 1988, could not be determined conclusively. It is believed that a pump start permissive was not satisfied.

Approximately one minute prior to the scram, alarms indicating loss of high speed (RR) pump permissives occurred. These alarms, if not cleared, would prevent high speed operation of the RR pumps. The Hathaway typer shows that these alarms did not clear before the scram. The Startrec data shows that the low FW flow condition existed when the RR MG set was started. Feedwater flow increased to above the high speed permissive approximately seven seconds after the MG set start. It is believed that shortly after this, the operator attempted to start the RR pump. In this condition, no pump start would be possible because the start logic would be routed to the High Speed relay, which was sealed out from the previous low FW flow condition.

Static "O" Ring (SOR) Performance

The SOR switches performed properly during the event on March 9, 1988. There were six (6) other SOR switches which utilized the same reference leg as DPS-2B21-N037BB. Two (2) of the switches have level 3 setpoints;

-2B21-N024B Reactor Vessel Low Water Level Scram, and
-2B21-N038B Reactor Vessel Low Water Level 3 Confirmed for ADS.
Three (3) of the switches have level 2 setpoints;
-2B21-N037BB and, 2B21-N037DB Division 2 RCIC Initiation, and
-2B21-N026BB Division 1 Primary Containment Isolation System (PCIS) Inboard Isolation function.
Two (2) of the switches have level 1 setpoints;
-2B21-N037BA Division 2 Permissive for ADS/Residual Heat Removal(RHR), and
-2B21-N037DA Division 2 Permissive for ADS/RHR.

Upon isolation of the reference leg from the variable leg, a low "indicated" level spike was received by the instruments which utilized the same reference leg as DPS-2B21-N037BB. The spike caused the level 3 switches (2B21-N024B and 2B21-N038B) to trip. 2B21-N026BB which gives 1/2 of a Level 2 PCIS Groups 2 through 5 isolation signal did not actuate as evidenced by the lack of an alarm on point R0873. The other SOR switches, which had lower setpoints, did not trip. These are discussed earlier under item #1 (ATWS performance).

During the time period between the trip of the RR pumps to the scram, vessel level did not approach level 3 (level remained above 30 inches). This was confirmed through discussions with the operating personnel involved in the event, and a review of upset, wide range, and narrow range level indications from control room recorders and Startrec.

Within 7 to 9 seconds following the scram, all 4 SOR low level (level 3) scram switches tripped, and the low level (level 3) confirmed alarm was received, demonstrating consistency in the response of the level 3 SOR switches. Startrec was not recording at the time of the scram, so the level at which the switches tripped is not known. There were no level 2 SOR initiations following the scram.

All SOR switches which utilized the same reference leg as DPS-2B21-N037BB were functionally tested prior to startup.

Feedwater and Feedwater Heaters

During normal steady state operation, feedwater heaters have level controlled via the normal drain valves to the next lower heater in a cascade (typical). Inputs to the feedwater heaters are turbine extraction steam and drain from the next higher heater in a cascade. During transient conditions where large drops in turbine load (steam flow) occur the extraction steam pressures change as well as the extraction steam flows. This affects the feedwater heater level in several ways including: steam flashing due to lower heater shell pressures, reduction in inputs due to reduced extraction steam flows, changes in the condensing rate due to reduced feedwater/condensate flow, etc. The heater level control system tries to react to this transient with the normal and emergency level control valves but it is designed for normal operation and does not react fast enough for this type of transient. The heaters trip (loss of the extraction input) due to high level to protect the turbine from water induction. The performance of the feedwater heaters after the March 9th Unit 2 scram was reviewed and found to have performed as would be expected from the large drop in turbine load.

During review of the feedwater system performance, it was noted that vessel level was cycling with a slightly larger band than normal. Vessel level was seen to swing inside a level band of approximately 15 inches, cycling on about a 30 second period.

During checkouts of the feedwater controls, a sticking actuator positioner on the 2A Turbine Driven Feed Pump steam control valve was found. This positioner was found to be causing a delay of approximately 5 to 6 seconds in the control valve response. The positioner was replaced during the unit outage, and verified to allow proper control valve response.

Subsequently, review of the control system data recorded during the March 9 transient indicated that the feedwater pump turbine control valve response delay was responsible for the swings in feedwater flow, which caused the vessel level swings. The positioner replacement is considered to be sufficient to resolve the questions about the level oscillations.

2E12-F009 Valve Failure to open when going into Shutdown (S/D) cooling on U-2.

The unit was cooled down to 299°F for 2 hours before trying to open the valve for the first time. The valve tripped on thermals the first try. The thermals were reset and allowed to cool for ~ 30 minutes, then the valve was tried again (this was ~0530 hours). It again tripped on thermals. At this time personnel were ready to go into the drywell. The decision was made to have the U-2 Foreman also go in with them to assist the valve off its seat manually. This decision was made in an effort to expedite getting S/D cooling on, in order to get into cold S/D so planned work could start. The valve was manually cracked off its seat by personnel making the initial drywell entry, (~0645 hours) and opened easily the rest of the way with the motor.

Pressurizing between the 006B and 009 valve with the Cycle Condensate System (CY) per LOP-RH-07 was not done because the time it would take would delay the start of critical path outage work.

The conclusion of the On-Site Review was to complete installation of Modification M-1-2-88-007 during the second refueling of Unit 2. This Modification will install a larger Motor operator on 2E12-F009 similar to the modified Unit 1 valve.

2. Perform an evaluation of operator performance during this event

Initial conditions on Unit 2 were 84% power (930 MWe) and steady state. LIS-NB-404 was in progress which tests the Reactor Core Isolation Cooling (RCIC) initiation at -50". This surveillance requires a Technician on headsets in the Control Room communicating with the Technician at the instrument rack. The Instrument Maintenance Department (IMD) Technicians received permission from the Shift Engineer (SE), then the Shift Control Room Engineer (SCRE), and lastly the Unit 2 Nuclear Station Operator (NSO) which is standard procedure. There were 2 NSO's at the Unit 2 Station, the Unit 2 NSO and the Center Desk NSO (Center Desk operates the common systems between Unit 1 and Unit 2). The SCRE was in his normal station of observation between the Units and the SE was in his office just south of the Control Room.

The initial sign of a problem was an alarm on the Reactor Control Panel (2H13-P603) which was a hi level alarm. The Center Desk NSO immediately assumed the Feedwater Control (FWC) station located at 2H13-P603. While reviewing FWC additional Reactor Water Level (RWL) related alarms indicating both hi and lo Reactor Water Level (RWL) were received on Control Room panels. A half-scram at +12.5" RWL also occurred. FWC appeared normal, in that it was responding to a level signal and there were no erratically functioning controllers; however, upon review of the 3 Narrow Range (NR) RWL indicators, the NSO saw 'B' NR at approximately 30" and rising while the 'A' and 'C' NR indicators were steady at approximately 40". The 'B' NR was providing the level signal to FWC. The NSO deduced an instrument problem and reset the hi RWL trip and the half-scram. He suggested that a Reactor Recirculation (RR) Pump runback may be in progress as indicated by rapidly decreasing Power, Feedwater Flow and Steam flow. The above occurred over a time span of about 23 seconds. This 1/2 isolation signal has not been possible to confirm. The 1/2 isolation should be accompanied by an alarm.

The Unit 2 NSO was reviewing the RR panel. He found RR flow at zero, no pump amperes, the slow speed motor-generator sets were not running and the Flow Control Valves (FCV) were open - not at minimum position as the case would be on a runback. There were Anticipated Transient Without Scram (ATWS) alarms on the panel which indicated to the operator the RR pumps had tripped in response to an ATWS signal. There also appeared to be a 1/2 Primary Containment Isolation System (PCIS) RWL trip present for the Main Steam Isolation Valves (MSIV's). This 1/2 isolation signal has not been possible to confirm. The 1/2 isolation should be accompanied by an alarm from point R0109 which would actuate if the local level transmitter (2B21-N402B) had spiked sufficiently. It is believed that the alarm at 2H13-P601 "DIV 2 RX LVL LO/PRESS HIGH" was interpreted as being the alarm associated with the low low level MSIV isolation. The alarm which did annunciate (recorder point R1235/window E303 at H13-P601) is driven from the Wide Range Level recorder 2B21-R884B, which is fed from level transmitter 2B21-N026BA at the same instrument rack (P027) where the valving error occurred. This window alarms at +12.5 inches, decreasing, and could easily be confused with the alarm at E504, which would actuate in conjunction with a 1/2 MSIV isolation on low reactor Level 1.

The Unit 2 NSO was cognizant of the actions taken by the Center Desk NSO. He also knew there was a surveillance in progress on a -50" RWL switch, consequently he suspected some sort of instrument problem and directed the Instrument Technician to stop what was in progress. The Technician acknowledged the direction and indicated he didn't think there was a problem with the surveillance. The U-2 NSO also reset the 1/2 PCIS signal.

The SCRE responded to the event when the initial RWL alarm occurred. He positioned himself at Unit 2 such that he could clearly observe operator actions and reactor parameters. He saw there was a problem with RWL indication and that the RR pumps had tripped off. He verified power had decreased and called the Shift Engineer to the Control Room. He reviewed the actions the NSO's had taken and found them proper.

The Unit 2 NSO also reviewed the feedwater heater situation since the rapid power reduction had caused many heaters to trip. He planned to re-open the extraction steam valves to regain some feedwater heating after the valves fully closed. He was also aware that a Shift Foreman was dispatched to the local heater controllers to aid in reestablishing feedwater heating. He placed FW temperature in a computer window to trend.

During the next few minutes preparation began for restart of the RR pumps as called for by LOA-RR-07. The Flow Control Valves (FCV's) on both pumps locked up as they were ramped to minimum position. An Equipment Operator (EO) was dispatched to reset the lockouts. This time frame is about 4 to 4-1/2 minutes into the transient (after the initial level alarm).

At approximately this point the IM Technician in the Control Room indicated the problem may have resulted from a valving error at the instrument rack.

The SE arrived in the Control Room approximately 3 to 3-1/2 minutes into the transient. His analysis identified that both RR pumps were off; Average Power Range Monitors (APRMS) were oscillating from 20-50% of scale; reactor pressure and level were normal; FWC appeared normal; Feedwater Heaters were tripping in response to the large downpower and FW temperature was decreasing but normal on a downpower trend. His initial comment was that a manual scram may be necessary, if we cannot stabilize the transient quickly.

At almost the same time the NSO at FWC asked him if the reactor should be scrammed. The SE told him to prepare for a manual scram at his (SE's) direction to which the NSO acknowledged.

The SE directed the U-2 NSO back to the RR station (he had returned to the feedwater heating station).

The SE directed the Shift Foreman at the heater controllers to place the heaters on emergency spills and that the Control Room would get back to him later.

The Unit 2 NSO was able to get the A FCV back to minimum position now since the EO had reset the lockout. The B FCV lockout wasn't reset as there was an abnormal signal alarm which would require additional operator actions. This occurred about 6 minutes into the transient.

The SCRE conferred with SE and recommended an attempt to restart RR before manually scramming the reactor. The SE's thought process ruled out a major problem due to loss of FW heating since the large power decrease (approximately 40%) had caused most of the 50-60°F reduction. He recognized the plant was in the instability region and that actions to leave the region were required. Thought was given to normal, in sequence Control Rod (CR) insertion, but there wasn't time for this. Also, the SE was not sure whether or not use of "Cram" arrays would lead to further local power problems, so he decided that any CR movement would be via SCRAM. A restart of RR per LOA-RR-07 could restore core stability. LOS-RR-SR1, Thermal Hydraulic Stability Surveillance, did not address an abnormal situation such as this. Since no abnormal procedure applied to the situation any more than LOA-RR-07 he agreed and directed the Unit 2 NSO to attempt a restart of RR. Two attempts to start 2A RR pump did not succeed. As the SE was about to direct a manual scram be carried out, the reactor tripped on high neutron flux. The reactor scram occurred about 7 minutes into the transient. The operators carried out the scram procedure without further incident.

The operators adhered to the station procedures and their actions addressed returning the reactor to a stable condition. Station review identified that adequate procedural guidance to this situation was not provided to the operators. Measures were taken to correct that deficiency. Command in the Control Room was clearly demonstrated by the SE. He took positive actions to return the plant to a stable condition. The SCRE assessed the event as it progressed and provided information to the SE. The NSO's demonstrated their abilities to correctly interpret control board indications and take the immediate actions. The Station's Assessment of the Operator Actions is that they were knowledgeable of the transient and plant indications and that their actions were prompt, responsive and proper.

3. Evaluate the adequacy of your Technical Specifications, operating procedures, abnormal operating procedures, and emergency procedures with respect to this event and vendor recommendations (GE SIL-380)

Following the scram of LaSalle Unit 2 on March 9, 1988, a review of operating procedures for normal and abnormal situations involving Reactor Recirculation (RR) pumps and/or core flow changes was conducted. Procedure changes were implemented which were intended to improve the timeliness of operator response to RR pump trips and/or neutron flux instabilities. The following list of procedures outlines the changes which were initiated. All procedure revisions are complete.

1. ABNORMAL PROCEDURES (LOA)

LOA-RR-06 SINGLE RR PUMP TRIP

Immediate Action: Insert CRAM rods to 00 if Flow Control Line (FCL) was >80% prior to pump trip, frequently MONITOR APRM and LPRM flux indications and either increase flow on the operating RR loop or decrease power with rods to exit region. References operator to LOA-RR-09 if instability is suspected.

Subsequent Action: Perform Stability surveillance LOS-RR-SR1, i.e., in SLO, may be in surveillance region.

LOA-RR-07 TWO RR PUMP TRIP

Immediate Action: Insert CRAM rods to 00 if FCL >80% prior to pump trip, and continue to insert rods to below 80% FCL, MONITORING APRM/LPRM noise. References LOA-RR-09 if instability is suspected.

Subsequent Action: Perform Stability surveillance LOS-RR-SR1

Added explanation of instabilities in Discussion section, including wording that states "Unstable neutron flux oscillations have occurred . . ." to emphasize that the phenomenon has actually been experienced. Explained that the basis of not restarting tripped pump(s) until below 80% FCL is to avoid diversion of operators attention from stability concerns.

LOA-RR-09 CORE INSTABILITIES (NEW PROCEDURE)

The operator is directed to this procedure by the RR pump trip LOA's, LPRM HI, APRM HI, LPRM DOWNSCALE, Thermal Hydraulic Stability Surveillance, Restart of Tripped pump(s), Changing RR pump speed from HI to LOW speed, and Pump Shutdown procedures whenever instability is suspected.

Immediate Actions: If FCL >80% and Core Flow <45%, insert CRAM rods to 00, then insert rods in sequence to get below 80% FCL. MONITOR APRM/LPRMs. If instabilities have not been terminated within 2 minutes SCRAM reactor.

Subsequent Actions: Perform LOS-RR-SR1, reduce FCL to below 80%, and continue monitoring APRM/LPRMs.

LOA 1(2)H13-P603:

WINDOW A407 LPRM DOWNSCALE

Note that a regular cycling of this alarm, especially at a 2-3 second period could be indicator of instability. Instructs operator to select the "yellow" stability monitoring rods. Refers to LOA-RR-09 if instability is suspected. Notes that Full-core display maybe observed for multiple alarms.

WINDOW A108 APRM HI

Instructs operator to observe APRM recorders and LPRM meters for flux oscillations >10% peak-to-peak. Refers to LOA-RR-09 if instability is suspected.

WINDOW A307 LPRM HI

Notes that periodic alarm may indicate instability. Instructs operator to select "yellow" stability monitoring rods. Refers to LOA-RR-09 if instability is suspected. Discussion describe conditions of possible instability, and indications, especially 2-3 second period.

2. SURVEILLANCES

LOS-RR-SR1 THERMAL HYDRAULIC STABILITY SURVEILLANCE

Revisions were made to let the operator obtain the raw noise data without delay, then compare to baseline data. A fixed criteria of 10% was introduced which would enable the operator to take corrective action prior to comparing all the results to 3 times the baseline.

Certain Control Rods highlighted with a yellow background to enable quick selection for LPRM monitoring.

The surveillance sheet was also re-formatted to eliminate look-ups by the operator, for determination of rod selections/core regions.

LOA-RR-09 is referenced for instability indications.

3. OPERATING PROCEDURES

LOP-RR-06 RESTART OF TRIPPED RR PUMP

Add reference to LOA-RR-09. Add prerequisite FCL less than or equal 80%. Add NOTE to watch out for instabilities with less than 45% Core Flow before/during decreasing flow on active loop to meet pump start requirements.

LOP-RR-08 CHANGING RR PUMPS FROM FAST TO SLOW

Add reference to LOA-RR-09. Add precaution that downshift, if above 80% FCL could result in operation inside stability surveillance region, and possible instabilities could result, complete FCL reduction to below 80% FCL if possible, prior to downshift. The first step after verifying proper RR equipment operation on downshift is to VERIFY core stability per LOS-RR-SR1.

LOP-RR-09 REACTOR RECIRCULATION PUMP SHUTDOWN

Add reference to LOA-RR-09. Add precaution that the flow decrease from RR pump shutdown may result in entry into stability surveillance region. Complete FCL reduction to <80% FCL prior to pump shutdown, if possible.

Instructs operator to VERIFY core stability after pump shutdown, referring to LOA-RR-09 if instability is suspected.

LTS-1200-4 NUCLEAR ENGINEERS DAILY SURVEILLANCE

Added procedure steps to ensure that the CRAM array check on the checklist includes verification that all CRAM rods are properly indicated with RED tape on select buttons.

LAP-100-13 CONTROL ROD SEQUENCE PREPARATION

--PROCEDURE DEFICIENCY WRITTEN, NO REVISIONS PERFORMED--

Procedure changes incorporated the requirement for the Nuclear Engineer to place and verify RED tape on the associated CRAM rod select buttons. Operator instructions to continuously insert all "taped" rods to position 00 and then sign off the appropriate INSERT steps, was incorporated. Attachment G (CRAM Array instructions) was revised to require the Nuclear Engineer to record the specific rods associated with the designated CRAM arrays.

In addition to the procedure review discussed above the Unit 1 and Unit 2 Technical Specifications were reviewed. As a result of discussions held with the AIT team members revisions to the LaSalle Unit 1 and Unit 2 Technical Specifications have been prepared and submitted to Offsite Review.

The revised procedures are fully consistent with General Electric Service Information Letter (SIL) 380 Revision 1. Changes to procedures needed to be consistent with the proposed Technical Specifications will be incorporated upon approval of the Technical Specification.

The Confirmary Action Letter (CAL) RIII-88-03 directed the Station to initiate a Manual Scram in the event that no reactor recirculation pumps are in operation in Conditions 1 or 2. This requirement has been provided to Station Operators via Special Operating Order 88-21. This Special Operating Order was reviewed by the AIT team leader prior to startup of Unit 2 following receipt of the CAL.

4. <u>Perform increased activity level sampling during Unit 2 startup to verify no abnormalities</u>

Daily readings of the Offgas pretreatment and offgas post treatment Radiation Monitors taken since March 19, 1988 show no evidence of changes in the fission gas release rates when compared to data at comparable power levels prior to March 9, 1988.

The twice weekly reactor water iodine and offgas analyses show the same recoil versus non-recoil pattern and full power adjusted release rates from the fuel when compared to data taken prior to 3/9/88.

The offgas pretreatment monitor and offgas post treatment monitors are operating at levels well below their alarm setpoints. The dose equivalent I-131 level is well below the (Technical Specification 3.4.5) 0.2 microcurie per gram limit.

The data collected as part of the evaluation plan is presented in Table 1. The monitor setpoints are listed as footnotes to the table.

Data collection and increased sampling of reactor water and offgas continues as stated in the evaluation plan. Unit 2 was operated at greater than 90% power from April 1, 1988, to April 5, 1988; the reactor water iodine and offgas analysis will continue at the twice a week frequency until April 22, 1988 at which time the normal frequency of once per week will be reestablished.

TABLE 1

Date	Power (MW_T)	Pretreat (mR/hr)	Post Treat (CPS) A	B	Noble Gases $\Sigma 7$ μci/sec	DE I-131 μci/g
3/19	1452	48	750	900	320	1.8 x ~~10~~ 10^{-4}
3/20	1306	40	600	750		
3/21	1396	41	650	800		
3/22	2705	120	1800	2200	570	1.4 x ~~10~~ * 10^{-4}
3/23	2600	400	3100	3010		
3/24	2885	400	2500	3000	670	1.8 x ~~10~~ * 10^{-4}
3/25	2877	400	3000	4000		
3/26	2715	350	2800	3300		
3/27	2779	380	3000	3800		
3/28	2762	390	4500	3900		
3/29	2791	400	3000	3800	920	1.7 x ~~10~~ * 10^{-4}
3/30	2342	210	2500	2900		
3/31	* 2825 ~~2725~~	400	4000	3000		
4/1	3273	620	6200	7500		
4/2	3247	700	6000	9000	1600	2.0 x ~~10~~ * 10^{-4}
4/3	3167	500	6000	8000		
4/4	3157	700	6000	7000		
4/5	3160	500	5000	7000		
4/6	1932	170	3400	3000		

Setpoints:

Pretreatment Hi 3,000 mR/hr based on 3.4 x 10^5 μci/sec T.S. 3.11.2.7 limit
Hi-Hi 5,000 mR/hr based on Post Treat Hi-Hi-Hi alarm setpoint

Post treatment Hi 50,000 cps Controls Bypass valve
Hi-Hi 100,000 cps Alert Level
Hi-Hi-Hi 1,000,000 cps Isolates Offgas System

* All corrections per telecon M.A. Ring with M.S. Turbak 4/25/88 MARing

5. <u>Submit to NRC Region III a formal report of your findings and conclusions within 30 days of receipt of this letter.</u>

This letter with the above four responses and the responses to the additional sets of questions in Attachments B, C, and D, contained herein fulfills this requirement.

ATTACHMENT B

COMMONWEALTH EDISON COMPANY RESPONSE TO

NRC AIT QUESTIONS ON MARCH 18, 1988

Following are Commonwealth Edison Company's response to the initial set of five (5) questions provided by the NRC Augmented Inspection Team on March 18, 1988.

(1) Are the existing procedures and instructions of GE SIL 380 adequate?

Procedures

(a) Time available for operator action -

Oscillations started within 5 minutes of pumps trip. Discussions during procedures development had estimated that 15 minutes would be available before the effects of the feedwater transient led to instability.

Justification for Adequacy of Manual Actions

Q(1)(a)(i) Immediate response to rod insertion has been the claimed response to previous events and tests of reactor stability. Can this be documented in terms of number of rods inserted, worth of rods inserted - selection and insertion procedures, and time from the start of the rod insertion decision until oscillations were terminated?

A(1)(a)(i) A review of stability experience was made with specific emphasis on operator actions in relation to the onset of oscillations. The events are split between special stability tests and events which occurred during normal plant operation. Of the four events which occurred during normal plant operation, three occurred at plants where SIL-380 recommendations had not been incorporated. Each event is briefly described in the following pages with particular emphasis on actions which started the oscillations and how the oscillations were mitigated. Table 1 provides a summary of the events.

In general, cases where oscillations were caused by the gradual withdrawal of control rods (as done during a normal startup sequence), the suppression of the oscillations required minimal control rod insertion (typically 1-8 rods inserted 0.5-1.0 foot) over a short time period (several minutes or less). Most of the successful actions also involved the insertion of relatively deep control rods (notches

08-20) which typically have the most affect on reducing core power. The major exception to this observation occurred when the oscillations were caused by a substantial withdrawal of a single control rod with the ensuing action only partially reinserting the control rod. Because of the flow biased neutron flux scram for the plant, an automatic scram occurred when the APRM oscillation magnitude reached 15% of rated peak-to-peak. For the cases caused by flow decreases, both control rod insertion and core flow increase proved to be adequate mitigating actions.

Based on the above experience, most oscillations should be readily mitigated by inserting several (4-8) deep control rods up to one foot. These actions would take only several minutes to perform and in many cases less action and time would be required. These actions are consistent with the CECo use of CRAM rods to reduce power following a LFWH or recirculation pump trip. For events where core flow increase is readily available, operational experience has also demonstrated that this is a viable method for easily mitigating oscillations.

1. Vermont Yankee (VY) - Test (1981)

VY was operating at the rated rod line and minimum forced circulation flow when both recirculation pumps were tripped during a stability test. The flow coasted to natural circulation and limit cycle oscillations of approximately 5-6% of rated, peak-to-peak were observed on the APRMs and LPRMs. Data were taken for several hours at this condition, during which the APRM oscillations increased to a peak of 10.8% peak-to-peak. LPRM oscillation magnitude was similar to the APRM oscillation and no LPRM alarms were received. During this time period, the core average power also increased (about 0.5% of rated). Six (6) control rods (notch 14-26) rods were each inserted one notch (6") and the oscillations returned to normal, <3% peak-to-peak. Exact timing of control rod insertion is not known but approximately two minutes would normally be required to insert the above described control rods.

2. BWR/4 - Operation (1982)

The plant was being started up at minimum forced circulation flow with the operator withdrawing control rods to reach the rated rod line. The operator withdrew a control rod seven feet in 70 seconds and immediately noticed large oscillations on the APRMs and LPRMs (>10% peak-to-peak). A TIP trace was initiated and 30 seconds later the rod was only partially reinserted (1.5 feet). A neutron flux scram (flow biased) occurred 30 seconds later (one minute after completion of rod withdrawal) with the APRM peak oscillation at 60% of rated. Oscillation magnitudes at the time of the scram were 15% peak-to-peak on APRMs and 40% of scale peak-to-peak for LPRMs. No LPRM alarms occurred. SIL-380 recommendations had not been incorporated at the time of the event.

3. BWR/4 - Operation (1983)

The plant was operating at 74% power and 66% flow, approximately on the rated rod line when a single recirculation pump trip occurred. The flow coasted down to approximately 38% of rated (near the minimum forced circulation flow for two loops operating). Two minutes after the pump trip, a loss of feedwater heater event occurred and reactor core thermal power begin to increase as feedwater temperature reduced. Four minutes after the pump trip, reactor power had increased to 59% of rated with feedwater temperature down to 300°F. At this time APRM alarms were received and the APRMs were observed to be oscillating at approximately 10% peak-to-peak. Five and one half (5.5) minutes after the pump trip a single control rod was inserted from the fully withdrawn position. An APRM flow biased flux scram occurred 30 seconds later (six minutes following the pump trip) at approximately 70% of rated flux. The APRM oscillations reached 25% peak-to-peak and no LPRM alarms were received.

4. BWR/4 - Test (1983)

The reactor was being operated at natural circulation conditions with power at 52.4% of rated. Control rods were being withdrawn when APRM oscillations of 5% peak-to-peak were noted. Control rods were withdrawn further until APRM oscillations were noted to increase. Oscillation magnitude continued to increase for approximately 5 minutes and stabilized at 12% peak-to-peak for APRMs and 60% peak-to-peak for LPRMs (no LPRM alarms). Four to eight control rods (positions unknown) were then inserted one notch (6") and the oscillation magnitude returned to normal (<5% peak-to-peak).

5. BWR/6 - Test (1984)

The reactor was being operated at natural circulation conditions with power at 45% of rated. Control rods were withdrawn until oscillations were noted on the APRMs and LPRMs. Over a five minute period, LPRM oscillations were observed to increase from 5% to 28% of scale peak-to-peak (no LPRM alarms). During this same time, the APRM oscillations increased from 2% to 9% of rated peak-to-peak. Control rods were then inserted (exact number and insertion not known, but time period indicates only several rods inserted several notches at most) and recorded traces showed the oscillation magnitudes decreased by approximately 33% over a 40 second period from the time of peak magnitude and start of control rod insertion. No additional traces were available but test crew observation was that oscillations rapidly diminished in magnitude following the control rod insertion.

6. BWR/6 - Test (1984)

The reactor was being operated at minimum forced circulation (minimum valve position, pumps at high speed) with control rods being withdrawn until oscillations were observed. Over a two minute period, the LPRM oscillations grew from 5% to 15% of scale, peak-to-peak (no LPRM alarms) and the APRMs grew from 2% to 4% of rated, peak-to-peak. Several control rods were then inserted (exact number and insertion not known, but time indicates only several rods inserted several notches at most) and recorded traces showed the oscillation magnitude decreased by approximately 50% over a one minute period from the time of peak magnitude and start of control rod insertion. No additional traces were available but test crew observation was that oscillations rapidly diminished in magnitude following the control rod insertion.

7. BWR/6 - Operation (1984)

The reactor was being operated with the recirculation flow control valves (FVC) partially open and pumps at low speed as part of a training startup during the initial test program. Reactor power was approximately 53% of rated and no feedwater heating existed because the turbine was offline and steam bypass was being used. BOP transient initiated a runback of FCVs and oscillations were immediately observed on the APRMs and LPRMs. The magnitude of APRM oscillations grew from 3% to 25% of rated peak-to-peak in two minutes and LPRM alarms on several detectors were noted during the oscillations. The operator was instructed to manually scram the reactor two minutes after the oscillations began. SIL-380 recommendations had not been implemented prior to the event.

8. BWR/6 - Test (1984)

The reactor was being operated with the FCVs at 30% position with the recirculation pumps at low speed during special stability tests. Reactor power was 50.9% of rated with approximately 40°F temperature decrease from normal due to the intentional bypassing of feedwater heaters during the test. Oscillations were observed on the LPRMs of 12% of scale peak-to-peak (no LPRM alarms) with APRM oscillations of3% of rated peak-to-peak. With four deep (notch 08) control rods inserted two notches each (1 foot) the reactor was stable (estimated time to insert control rods is 1-2 minutes).

9. BWR/6 - Test (1984)

The reactor was being operated along the maximum extended rod line (approximately 120% rod line) with the recirculation pumps at low speed and FCVs at approximately the 30% position. The FCVs were closed to the 23% position and oscillations were observed on the APRMs and LPRMs. The FCVs were then closed to the minimum position and the oscillation magnitude was observed to increase. The peak LPRM oscillation magnitude was 35% of scale (no LPRM alarms) with an APRM oscillation magnitude of 5% of rated peak-to-peak. Operation continued at this condition for 15 minutes with no change in character of the oscillations. The operator then slowly opened the FCVs to 50% position (5 minutes) and the oscillation magnitude was observed to slowly decrease as flow increased. At 50% FCV position the flux noise had returned to normal.

10. BWR/3 - Operation (1985)

The reactor was being started up along the minimum forced circulation line at approximately 55% of rated power. During control rod withdrawals, oscillations were observed on the APRMs of approximately 5-10% of rated peak-to-peak. Two relatively deep control rods (notch 20) were inserted one notch (6") each and the APRM magnitude returned to normal (less than one minute for control rod insertion and oscillation reduction). Withdrawal of different control rods again resulted in APRM oscillations, this time with a magnitude of approximately 10-15% of rated peak-to-peak. Seven shallow (notch 46) control rods were inserted one notch (6") each and the oscillations were mitigated (control rod insertion took less than five minutes). Once again a different control rod was withdrawn and oscillations were again observed on the APRMs of 10-15% of rated peak-to-peak. One deep control rod (notch 02) was inserted one notch (6") and the oscillations were mitigated (control rod insertion took much less than one minute). Core flow was then increased approximately 5% of rated and control rods were successfully withdrawn to the desired rod pattern. SIL-380 recommendations had not previously been incorporated into plant procedures.

Q(1)(a)(ii) How can the reliability and effectiveness of the manual insertion procedures be improved? Considerations -

- Select __________ rods for insertion sequence which typically takes _x_ minutes after two pump trips or _y_ minutes after observed violation of stability acceptance criteria. If instability is observed after completion of this initial process, manual scram should be required.
- Restart recirculation pumps if permissive light is available to show that all permissives have been cleared (viable?).
- Consider the use of an on line stability monitor (similar to the ORNL noise algorithm) for more rapid and reliable surveillance of approach to instability.

A(1)(a)(ii) Response (1)(a)(i) addresses the issue of the effectiveness of deep control rod insertions. The response below addresses LaSalle's procedure to rapidly insert control rods.

CRAM rods are designated per LAP 100-13 (Step F.3) for emergency load reduction to ". . . strongly reduce the operating flow control line to avoid a reactor scram." The associated rod's are designated on Attachment G of LAP 100-13, and kept with the control rod sequence package. These rods are also flagged with small strips of RED translucent tape placed on the appropriate rod select buttons. The operators are instructed to continuously insert each CRAM rod to position 00.

After the operator has inserted all CRAM rods, he will go through the applicable sequence steps (which are listed on Attachment G and denoted on the sequence pages with "CRAM" next to the step) and initial the INSERT column(s). Upon completion of these actions, the operator will resume rod insertions at the back of the sequence, if needed.

The proper choice of CRAM rods is highly dependent on the existing rod pattern, and these rods cannot be permanently designated. Some situations require that the operator does NOT have CRAM rods available (especially low power, near the Rod Worth Minimizer Low Power Setpoint). Because of this, the Qualified Nuclear Engineer issues Attachment G and verifies the application of the tape to the correct rods. The general criteria for CRAM rod designation is that the CRAM rods are deep rods (BPWS groups 9 or 10), and are at positions between 08 and 24. The number of rods designated varies but is usually chosen to achieve from 6 to 12 percent rod line reduction.

Assurance that the CRAM rod tape is correct is obtained daily during performance of the Nuclear Engineers Daily surveillance LTS 1200-4. A procedure step and surveillance sheet checkoff verify that the CRAM rods are correctly specified both on the panel (buttons) and in the sequence package. This is to ensure that the operator will not inadvertently insert the wrong rods.

As recommended in SIL 380, control rod insertion is the preferred method of leaving the region where there is marginal room to stable operation while in natural circulation. LaSalle procedures have been modified to reflect this. LaSalle is evaluating the installation of a permissive light for recirculation pump restart. LaSalle is also evaluating several different types of stability monitors. No decisions on these plant modifications have been reached at this time.

Q(1)(a)(iii) How can the adequacy of automatic scram protection be demonstrated?
- Can it be shown by analyses that inherent shutdown mechanisms such as Doppler will limit, the peak, power level
- even under conditions of regional oscillation such that safety limits will not be violated before 118% power APRM scram occurs. What are the limitations of the analysis in terms of fuel design applicability or other factors?

A(1)(a)(iii) This issue is being discussed with the Boiling Water Reactor Owner's Group (BWROG). Commonwealth Edison will inform the NRC on developments and schedules as they occur. A status report will be provided by July 1, 1988.

Q(1)(b) In view of the ATWS implications of the LaSalle Unit 2 incident, review the generic stability analysis in the ATWS report. Address the adequacy of the ATWS resolution, i.e., recirculation pump trip, considering that LaSalle 2 could not have tripped on return to 118% power. Do the ATWS assumptions consider the implications of regional instability?

A(1)(b) The 1979 GE Generic ATWS report, "Assessment of BWR Mitigation of ATWS" (NEDE-24222), addresses stability related oscillations associated with a postulated ATWS event. This report specifically investigated the sensitivity and potential impact of limit cycle oscillations on fuel integrity. Limit cycle neutron flux oscillations up to 500% of rated bundle power were analyzed (since no scram occurs, whether the oscillations are regional or core wide is irrelevant, the maximum amplitude is the important parameter). The fuel clad temperature response was evaluated assuming the fuel was already in boiling transition due to the ATWS event. The resulting peak-to-peak fuel clad temperature variation was 130°F for a limit cycle frequency of 0.125 Hz, decreasing to 50°F for a frequency of 0.25 Hz. Since the limit cycle frequency in a BWR is typically 0.3-0.5 Hz, the calculated temperature response is conservative. Even with this conservatism, it was concluded that fuel integrity is not significantly affected by the limit cycle induced temperature variations.

The potential for limit cycle oscillations during an ATWS event was recognized by the NRC as a result of the GE assessment and oscillations observed at an operating BWR. GE provided several additional technical presentations to the NRC staff and ACRS expanding upon the NEDE-24222 conclusion that the fuel thermal duty was not severe. It was also shown that even if prolonged exposure to limit cycles resulted in a loss of clad integrity, the failure would not impact the ability to cool the core and any incremental radiological consequences would be small and bounded by the generic ATWS assessment. Given the importance of the recirculation pump trip (RPT) in minimizing the energy deposited in the pressure suppression pool (thereby maintaining containment pressure within limits) during an ATWS event, the GE analysis demonstrated that the potential consequences of oscillations during an ATWS event are acceptable. When the NRC issued their standards for the reduction of risk from ATWS events (Federal Register/Vol. 45., No. 226/November 24, 1981) the possibility for oscillations following the RPT was specifically noted in the context of, "given a trip of the recirculation pumps ... a static or oscillatory equilibrium will be maintained ...".

Based on the above, it is concluded that the potential for limit cycle oscillations during an ATWS event has been thoroughly reviewed by the NRC in arriving at the ATWS rule (10 CFR 50.62), specifically the requirement for RPT. Furthermore, the analysis specifically considered very large oscillations which have been hypothesized to be possible during regional instabilities.

Q(1)(c) The predicted decay ratio for LaSalle 2 Cycle 2 was 0.60. Based on results of the recent incident, it seems clear that both LaSalle 1 and 2 are potentially unstable in natural circulation. Therefore, we will require that procedures and Tech Specs required by GL 86-02 be implemented on both units (as if DR > 0.80). Evaluate and explain why there was 40% error in the predicted decay ratio. How can we continue to rely on calculations to demonstrate stability? Should GL 86-02 requirements apply to all BWR's without waivers by calculations?

A(1)(c) To clarify the condition of the reactor following the recirculation pump trip on March 9, 1988, at LaSalle-2, a specific analysis using actual plant data recorded during the event was performed. Because the conditions following the pump trip were not at steady state, sensitivities to the parameters which were varying (core power, core flow, core inlet enthalpy, power distribution) were evaluated. Preliminary calculations predict core decay ratios varying between 0.79 and 0.92. For all cases analyzed, the channel decay ratios were less than 0.53. Since it is known from plant data that the stability of the core was varying during the time following the pump trip (stable for the first five minutes, varying degrees of instability from five to seven minutes following the pump trip) these preliminary calculations are consistent with the observed behavior of the plant.

Also, the core-wide instability observed is consistent with the high core decay ratio and relatively low channel decay ratio.

Available sensitivity studies indicate that variations in total core flow and power distribution had the most effect on the stability margins. From STARTREC traces recorded during the oscillations, the core flow varied by as much as 3% of rated with a minimum indicated flow of approximately 27% of rated. This value is 3% of rated below the value assumed in the licensing calculations and is a large contributor to the reduced stability margins at the actual plant conditions.

Because the reactor was not at steady state conditions following the pump trip, considerable uncertainty in the state variables exist. Therefore, additional calculations are currently being performed to better assess the sensitivity of the core decay ratio to these uncertainties. However, based on the preliminary calculations discussed above, decay ratios indicative of limit cycle oscillations were predicted for LaSalle-2 at the conditions experienced following the pump trip event. The primary difference between the licensing predicted decay ratio and the actual decay ratio can be attributed to the transient conditions that resulted following the pump trip.

Final calculations will be provided to the NRC when they become available. We anticipate submittal of the final analyses by May 15, 1988.

Q(1)(d) LaSalle 2 has very limited capability to record LPRM traces and other data that would be needed to evaluate possible violation of safety limits if regional oscillations were to occur. Discuss the adequacy of existing instrumentation and recording capability (LPRM alarms, operator observations and automatic recording, etc.) for evaluation of such events as discussed in SIL 380, item 9.

A(1)(d) Two LPRMS will be input into Startrec. The general question on the adequacy of plant instrumentation will be addressed through the BWROG. At this time, Edison expects to update this response by July 1, 1988.

Q(1)(e) Address the effects of cold water insertion on restart of recirc pumps after loss of feedwater heaters and two pump trips. Also address the effects on power distribution of inserting rods prior to the recirc pump start. Is the selected configuration for CRAM rods the same as for LoFWH procedures? Have rod blocks been considered in the selection?

(A)(1)(e) During natural circulation operation of a BWR, the mass flow rate of saturated fluid from the steam separators is four to five times greater than the mass flow of feedwater entering the vessel. The feedwater mixes with the saturated fluid in the downcomer region of the vessel and is then drawn through the jet pumps and into the core as a result of the natural circulation process. As colder feedwater enters the vessel, it mixes with the saturated fluid and a gradual decrease in core inlet temperature occurs. As this fluid passes through the core during natural circulation conditions, a gradual increase in core average power occurs. Under these conditions, the restart of a recirculation pump will not result in a cold water insertion event for the core. The water entering the core after the pump is started is no colder than the water entering the core during natural circulation conditions. Therefore, the core response is only affected by the increased core flow rate (which sweeps voids from the core resulting in a reactivity increase) caused by the pump start. A more limiting condition exists when the fluid in the recirculation loops is at a much lower temperature than the fluid in the downcomer region. If a recirculation loop is started under these conditions, the reactivity increase can be attributed to the sweeping of voids from the core caused by the increased core flow rate and to the reduced temperature of the recirculation loop fluid as it is swept into the core. Under these conditions, the core does experience a cold water insertion because of the lower temperature of the recirculation loop which had not been mixing with the downcomer fluid prior to the pump start. This event is explicitly analyzed in the FSAR and the consequences are negligible (MCPR remains substantially above the safety limit MCPR). Therefore, the affects of starting a recirculation pump after loss of feedwater heaters and a two pump trip is bounded by the FSAR analysis for idle recirculation loop startup.

Selection of control rods in the CRAM array used to reduce power following a two pump trip is based on achieving approximately a 10% reduction in the rod line while minimizing the effect on power distribution and future rod movement. In general, deep control rods are chosen and can be fully inserted with minimum impact on core peaking. These deep rods can provide the necessary power reduction and are not difficult to return to their original position following pump restart. Although some increase in peaking will occur, the power reduction capability of the CRAM rods justifies this technique for use in conjunction with SIL-380 recommendations following a two pump trip. In accordance with normal operating practice and procedures, the operators will consult with the station nuclear engineers prior to power increases following control rod motion, i.e., insertions of CRAM rods. At that time, peaking would be assured to be within acceptable limits prior to restarting the recirculation pumps.

The selected configuration for the CRAM rods is the same as for the LFWH procedures. Rod blocks do not have to be considered in the selection of the CRAM rods since no control rod blocks will occur during rod insertion at the power levels where the CRAM rods would be used.

(2) Are the Technical Specifications adequate?

Q(2)(a) What is the frequency of 2 pump trip with reactor remaining at power? (Should manual scram above the 80% line be a permanent requirement?)

A(2)(a) General Electric has no rigorous value for the frequency of two recirculation pump trips that is based on a complete review of actual plant experience. GE internally used a value of 0.25 events per plant year. However, review of the basis for this number indicates that this is only an estimated value and is not based on actual plant experience. Because recirculation pump trips do not always result in a reactor scram or significant unavailability, these events are not necessarily available in existing databases. A review of readily available information has identified at least four dual recirculation pump trips in the last five years, three of which did not result in an automatic scram caused by the pump trip. However, these results are provided for information only since a rigorous review of plant experience was not possible.

(NRC Question in parentheses was identified only as an NRC comment and therefore does not require a response. The current belief of the BWROG is that control rod insertion is an adequate and appropriate response to two pump trips.)

Q(2)(b) Technical Specification Changes will be required for LaSalle Unit 1 prior to restart. Technical Specification Changes for LaSalle Unit 2 should be submitted within 30 days. Manual scram will be required from above the 80% rod line until relief of this requirement is obtained.

A(2)(b) Technical Specification Changes for both units are being prepared to fully implement SIL 380. The proposed changes will not require scram, unless flux oscillations are observed.

The proposed Technical Specification (TS) divides the recirculation loop operability requirement (TS 3.4.1.1) from the thermal hydraulic stability requirement (TS 3.4.1.5). Both topics were previously covered under TS Section 3.4.1.1. Proposed TS Section 3.4.5.1, Thermal Hydraulic Stability, allows operation in the following three conditions: 1) with core flow greater than or equal to 45% of rated, or 2) with thermal power in the allowable region, or 3) with thermal power in Region 2 and acceptable APRM/LPRM noise.

The actions for failure to meet the LCO are divided by region of operation. In Region 1, with one or more recirculation loops in operation, Region 1 must be left within two hours using either control rod insertion or core flow increase. In Region 1, with no recirculation loops in operation, control rods must be inserted to reduce the thermal power below 36% of rated. If the LPRM/APRM noise levels exceed 10%, the reactor is to be scrammed. Failing to meet the above for no recirculation loops, the reactor is to be placed in hot shutdown within six hours.

In Region II and with reactor noise beyond acceptable limits, immediate action is to be taken to make the noise level acceptable. In the next two hours, Region II must be left for the allowable region. This may be accomplished using either control rod insertion or core flow increase.

The surveillance requirements apply only to operation in Region II. APRM/LPRM noise must be checked to see that it does not exceed the larger of three times the established baseline or 10% peak-to-peak. The surveillance is to be performed at least once per twelve hours and within 30 minutes of entering Region II after a 5% power increase. The core flow must also be verified to be greater than or equal to 39% at least once per twelve hours.

Q(2)(c) Resolution of the wording on response to two pump trip or exceeding surveillance criteria is needed.

Susquehanna wording is acceptable to staff. Staff considers that "Immediately" implies prompt response commensurate with other high priority actions for the event.

A(2)(c) See Response (2)(b).

Q(3) Staff is interested in simulator changes as a result of the event and wish to be kept informed of progress.

A(3) Software engineers are actively pursuing a method of demonstrating the oscillation phenomena experienced by the low flow/high power condition during the March 9 double recirculation pump trip at LaSalle.

To date, APRM indicators are capable of displaying oscillations such as experienced, LPRM high alarms are capable of oscillating in and out. Additional work is being done to simulate localized oscillations to reflect the local power/flow relationship.

Additionally, a scenario has been drafted to use for training and demonstration of a 1 or 2 pump trip condition. It is expected that modeling will be completed for use in training by July 1, 1988.

Q(4) Where is the applicable analysis for this event? Describe the analysis performed and its applicability.

A(4) As discussed with the AIT members during the exit meeting, NEDE 24011 describes the analyses performed for stability events.

Q(5) There is a concern regarding the accuracy, timeliness, and effectiveness with which pertinent information on this event was reported to the NRC. While the requirements of 50.72 regarding immediate notification were satisfied, information regarding the neutron flux oscillations was not promptly reported to the staff. CECo is requested to address this concern including the adequacy of the existing reporting procedures and any revisions that may be necessary to preclude any delays and pertinent information for future potentially significant events that may occur.

A(5) LaSalle has reviewed the requirements of 10CFR50.72 as they apply to the event of March 9, and believes that the only applicable category was the 4 hour report for the RPS actuation required by b.2.ii. In fact, the call was made within one hour. At this time the oscillations were still being examined, although not by the individual who made the notification. Subsequent review did not determine that any unexpected events occurred. Several conversations were held with Region III personnel regarding the observation of flux oscillations.

1.a.i

TABLE 1 - SUMMARY OF OPERATOR ACTIONS

		INCEPTION MAGNITUDE		PEAK MAGNITUDE				ACTION TAKEN					
								RODS INSERTED					
#	INITIATOR	APRM[a]	LPRM[b]	APRM	LPRM	LPRM[c] ALRM	TIME[d] TO PEAK	#	FT	POS	TIME[e]	EVENT TERMINATION	TIME[f] AFTER ACTION
1	FLOW	5-6	5-6	11	10-15	N	2 h	6	0.5	D[g]	2 h	SAME	2 m
2	RODS	10	-	15	40	N	1 m	1	1.5	S	30 s	AUTO SCRAM[h]	30 s
3	FLOW/LFLH	10	-	25	-	Y	2 m	1	12.	S	1.5 m	AUTO SCRAM[h]	30 s
4	RODS	5	20	12	60	N	5 m	4-8	0.5	-	5 m	SAME	2 m
5	RODS	2	5	9	28	N	5 m	4-8	0.5	-	5 m	SAME	2 m
6	RODS	2	5	4	15	N	2 m	4-8	0.5	-	2 m	SAME	2 m
7	FLOW	3	-	25	-	Y	2 m	-	-	-	-	MANUAL SCRAM	-
8	RODS	3	12	3	12	N	1 m	4	1.0	D	1 m	SAME	1 m
9	FLOW	3	10	5	35	N	30 m	FLOW INCREASE			30 m	SAME	< 5 m
10	RODS	5-10	-	5-10	-	N	-	2	0.5	D	-	SAME	1 m
	RODS	10-15	-	10-15	-	N	-	7	0.5	S	-	SAME	5 m
	RODS	10-15	-	10-15	-	N	-	1	0.5	D	-	SAME	< 1 m

a APRM magnitude in % of rated, peak-to-peak
b LPRM magnitude in % of scale, peak-to-peak
c LPRM upscale alarms, Y = alarms occurred, N = no alarms received
d Time from inception of oscillations
e Time from inception of oscillations
f Time from start of action (most cases estimated from observations and time to complete action)
g D - deep rods (< notch 24), S - shallow rods (> notch 24)
h Flow Biased Neutron Flux Scram (setpoint is 60-70% of rated)

ATTACHMENT C

COMMONWEALTH EDISON COMPANY'S RESPONSE TO NRC AIT QUESTIONS ON MARCH 23, 1988

Following are Commonwealth Edison Company's responses to the second set of seven (7) questions provided by the NRC AIT on March 23, 1988.

Q.1 Startrec was necessary to analyze the event. What parameter should be used to trigger if a similar event occurred?

A.1 The Startrec information provided valuable information which, if not available, would have complicated and delayed the analysis of the event. This would be a CECo liability, but availability of Startrec information is not a plant design or operational requirement. The Sentinel work file was configured to initiate if APRM exceeded 112% neutron flux indication, rising. The lack of a trip on this parameter during the transient was considered as further indication that the 118% flux scram setpoint had not been challenged at any time other than when the scram occurred. Also see Response (1)(d) in Attachment B.

Q.2, 3 Does the LPRM alarm filtering affect the ability to detect oscillations? What indication keyed the operators that oscillations were present.

A.2, 3 The operators noticed the oscillations because of the swings of the APRM recorders. During the post-trip review, the conclusion was made that the flux oscillations started when the LPRM downscale alarms began cycling every 2 seconds. Only 3 annunciator inputs are time filtered (APRM HI, LPRM HI, ROD BLOCK). The LPRM Downscale alarm is not time filtered. The time filtering of less than 0.1 seconds on the LPRM HI is not considered to be a significant obstacle to detection of instabilities. LPRM and APRM flux signals are used as the primary indicators of instability. The annunciators are used as possible keys to cause the operator to go check the APRM and LPRM meters at times when he might not normally do so.

Q.4 The NRC takes exception to the statements in the LaSalle On-Site review that the NRC and GE agree that this phenomenon is not a safety concern. Fear was expressed that this statement might encourage operators to treat this as a trivial event.

A.4 GE Topical report NEDE-24011 presents the analysis of oscillations and the conclusions that this phenomenon will be terminated by a high flux scram without any fuel damage occurring. In 1985 the NRC issued a SER accepting the GE report and its conclusions, and accepted NEDE 24011 for reference in licensing submittals. This apparent bounding of the effects of oscillation is what led to the statement that there were no safety concerns. However, the lack of safety concerns by no means implies that this is not a significant event. We believe, for instance, that because of the detailed analyses done, a Design Basis Accident (DBA) is not a safety concern, because the plant and public are protected. Even though there is no safety concern, the DBA is not treated as a trivial event. Nor is the existence of oscillations. The shift briefings, delayed startup, mandatory scram requirement, and other procedural changes have already served to highlight the significance of the event. Discussions with the training department ensure that this wording will not be misconstrued in future training sessions.

Q.5 What is indicated power at time of LPRM HI alarm?

A.5 At steady state conditions, an LPRM indication of 100 is calibrated to equal the fuel LHGR limit. For all of the LaSalle 2 Cycle 2 fuel, this is 13.4 KW/ft. Subsequent to the AIT exit, CECo reviewed the LPRM setpoints and determined that the LPRM HI alarm setpoint is 100% of scale. At the LPRM HI alarm setpoint, the thermal heat flux is not equal to 13.4 kw/ft. when the LPRM HI alarm occurs because of the thermal time constant of the fuel. The duration of the LPRM HI alarm cannot be rigorously used to determine the length of time that the neutron flux exceeded a reading of 100 because the alarm actuates if ANY LPRM is in alarm. Therefore, the first LPRM to exceed 100 will initiate the alarm and the last one to go below 100 will allow it to reset. Even so, it can be seen that the duration of the LPRM HI alarms is generally less than 150 milliseconds.

Q.6 What was the core maximum peaking factor at the time of the event?

A.6 The normally scheduled Core Performance Log (P1) printed at 1600 on 3-9-88 (1.5 hours before the event). The peaking factor was + 2.112 ("Design" peaking factor is 2.408). Since the unit was at steady state up to the event, the number correctly specifies the peaking factor at the time of the event.

Q.7 Have CRAM rods and stability monitoring rods been "taped"?

A.7 Yes

ATTACHMENT D

COMMONWEALTH EDISON COMPANY'S RESPONSE TO NRC AIT QUESTIONS ON MARCH 24, 1988

Following are Commonwealth Edison Company's responses to the third set of three (3) questions provided by the NRC AIT on March 24, 1988.

Q.1 Power Distribution - LPRM alarms occurred at an APRM level of 87 percent. This implies a shift in power distribution, since there should normally be substantial margin to the high LPRM level when APRM level is at 100 percent. Provide the available information on power distribution prior to the event and explain why LPRM alarms were triggered at the 87% APRM level. Is the LPRM Hi setpoint level equivalent to 105 watts/cm? Is it based on the allowable LHGR or simply to indicate that the instrument is off scale?

A.1 Summary

The occurrence of LPRM Upscale and Downscale alarms during the LaSalle-2 instability are consistent with the expected response of the core based on the APRM response. Because of a shift in power distribution following the recirculation pump trip and the phase relationship between LPRMs at different axial locations, LPRM alarms occurred at lower APRM levels than would be expected during steady state operation. The increase in power distribution was caused by the reduction in core flow following the recirculation pump trip which moves the boiling boundary lower resulting in a more bottom peaked axial power distribution. The phase relationship between the LPRM levels is a result of the density wave oscillation that is causing the core nuclear-thermal/hydraulic instability. Perturbations in coolant density must travel the length of the channel and therefore the neutron flux response to the perturbations is delayed in time at the higher levels in the core. These two factors are shown to explain why the LPRM alarms were triggered at the 87% APRM level.

Evaluation

Figures 1 and 2 show the raw LPRM readings before the recirculation pump trip and just prior to the onset of oscillations. As noted above, there indeed was a shift in power distribution during the event, but the shift was caused by the reduction in core flow caused by the pump trip. This shift in the axial power shape towards the bottom of the core is a typical occurrence for a flow decrease. The primary cause of the shift is the lowering of the boiling boundary at the reduced core flow rate. As shown in Figures 1 and 2, the peak to average LPRM reading increased from 1.31 to 1.64 as a result of the flow decrease. This shift in power distribution alone is a major contributor to why the LPRM alarms were triggered at the 87% APRM level.

Another factor that must be considered in the relationship between the LPRM and APRM signal is the phase lag that occurs from the bottom to the top of the core during density wave oscillations. Since the oscillations are caused by a perturbation in the coolant density, the effect of the perturbation must travel up the channel before impacting the higher level LPRMs. This propagation of the perturbation causes a phase shift between the signals at the four LPRM levels. The effect on the APRMs is that each LPRM level does not react its peak at the same time and therefore the APRM to LPRM relationship during these transient conditions is not the same as it would be during steady state operation. Figure 3 shows an example of how the phase relationship affects the APRM to LPRM relationship. Four LPRMs (Levels A, B, C and D) are assumed to be oscillating with the same magnitude but 90° out of phase (A to D level). The average of the four signals (indicative of what an APRM signal would do) oscillates at the same frequency but its peak magnitude is not as high as the peak of each individual LPRM since the four peaks do not occur at th same time. However, since the LPRMs are indicating a true phase lag between the oscillations at different axial locations, the APRMs are correctly measuring the core average neutron flux during core wide oscillations.

An analysis has been performed for the LaSalle-2 conditions at the onset of oscillations. The response of the LPRMs assigned to APRM Channel A have been modeled by a higher order sine wave (necessary to match the known non-linear characteristics of the oscillations). The LPRM with the highest average reading is assumed to oscillate up to 100% of scale (LPRM Upscale alarm setpoint) and the remaining LPRMs in APRM Channel A are assumed to oscillate with the same relative magnitude. This assumes that the peak-to-peak magnitude normalized to the average value is relatively constant for all LPRMs in the core (i.e., no shift in "peaking" during the oscillations). This assumption has been previously proposed and supported by data from the Vermont Yankee Stability tests. For the LPRM levels above the boiling boundary (B, C and D), the relative oscillation magnitude is assumed to be 1.2 times the relative magnitude for the A level LPRMs to account for the increased sensitivity to density perturbations in the voided regions (higher void coefficient). This relationship was also determined from the Vermont Yankee test data.

The APRM signal is the average of the 21 LPRMs assigned to the channel with an appropriate gain adjustment determined from the known values prior to the pump trip. The phase lag between the four LPRM detector levels is based on actual test data from Caorso which shows approximately an 8[illegible] shift from the A to D level. Figure 4 shows the results of the above analysis. For the peak LPRM oscillation just up to the LPRM Upscale alarm setpoint, APRM A is predicted to reach 84.5% of rated which is very close to the value estimated from data recorded during the event. The analysis also predicts that several of the D level LPRMs will go below the LPRM Downscale setpoint (5% of scale) and that LPRM Downscale alarms should occur before the first LPRM Upscale alarm is reached. The analysis also estimates that for APRM oscillations with a peak of less than approximately 74% of rated, no downscale alarms should occur. From the Hathaway Event

Recorder, two time periods after the onset of oscillations do not have LPRM downscale alarms. Review of STARTREC data during these two time periods shows that the APRM oscillations do not exceed 74% of rated during these two periods. Therefore, these results are consistent with the observations and recordings during the event and demonstrate that the model accurately predicts the relationship between the LPRMs and APRMs during the LaSalle-2 oscillations.

For a discussion of the LPRM Hi setpoint level, see the response to Question 5 of Attachment C.

Q.2 Is the filter circuit which prevented a Power/Flow scram typical of other reactors? Since power/flow scrams have occurred for similar events in foreign reactors, justify the difference in the protective system design. Also justify the time delays on the LPRM circuitry and the operating practices to preclude LPRM alarms, which are one of the early indicators of instability.

A.2 The Simulated Thermal Power Trip (STPT) circuitry is typical of all BWR/5 and BWR/6 plants and has been retrofitted into other reactor types as shown in Table 1. The STPT circuitry processes the Average Power Range Monitor (APRM) neutron flux signal through a filtering network with a time constant which is representative of reactor fuel thermal dynamics. This signal closely approximates the average thermal power during transient and steady state conditions. The STPT is a flow-referenced trip and is independent of the 120% neutron flux trip signal. No FSAR analyses are affected by the STPT circuitry since no credit is taken for the flow-referenced STPT scram. The STPT circuitry reduces unnecessary challenges to the Reactor Protection System (RPS) caused by momentary neutron flux spikes which may be produced by flow excursions in the recirculation system, transients during turbine stop valve tests and other vessel pressure perturbations. These spurious scrams are unnecessary challenges to the RPS since the neutron flux spikes represent no decrease in fuel thermal margins, especially in the low flow regions.

Table 1 - U.S. BWRs with STPT*

Brunswick 2, 3
Hatch 1, 2
Browns Ferry 1, 2, 3
Fitzpatrick
Fermi-2
Shoreham
Ham Creek
Susquehanna 1, 2
Hanford-2
LaSalle-1, 2
Nine Mile Point-2
River Band
Grand Gulf
Perry
Clinton

As discussed in the response to Questions 2 and 3 of Attachment C, the time filtering of less than 1 second on the LPRM Hi is not considered to be a significant obstacle to detection of instabilities. The filter prevents occurrence of nuisance alarms when operating at or near full power. Thus allowing the LPRM Hi alarm to remain an effective indication of high local flux.

* Based on information currently available to GE.

Q.3 It is the staff intent that technical specifications and operating procedures be designed to provide for suppression of neutron flux oscillations without reliance on high flux level (118%) scram. Unless there is reasonable expectation that this objective can be achieved, the operator should respond to instability conditions with a manual scram.

A.3 This is an NRC Staff statement requiring no specific response.

FIGURE 1 - LPRM READINGS BEFORE PUMP TRIP

AVERAGE = 51.1
MAXIMUM = 66
PEAKING = 1.31

		8	16	24	32	40	48	56
57	D		27	38	38	34		
	C		35	45	47	41		
	B		32	39	36	39		
	A		29	38	32	35		
49		30	46	52	55	47	42	
		41	59	58	64	54	54	
		42	63	60	61	56	61	
		33	60	61	62	61	50	
41		41	56	53	49	56	53	35
		50	58	59	55	63	55	41
		53	59	54	55	I	56	38
		62	58	I	55	55	59	33
33		51	52	49	49	50	49	42
		63	58	55	I	56	56	50
		56	59	55	61	57	57	37
		58	60	I	65	56	61	29
25		46	57	52	50	57	54	39
		55	62	I	60	66	56	44
		56	63	I	61	60	57	39
		64	60	58	56	56	56	36
17		36	51	54	53	57	46	28
		45	61	53	60	57	57	32
		50	67	54	61	58	63	32
		57	62	I	57	58	59	27
9			39	47	50	45	34	
			48	57	59	52	42	
			53	56	53	55	43	
			57	62	56	63	33	

I = Inoperable LPRM

FIGURE 2 - LPRM READINGS AFTER PUMP TRIP

AVERAGE = 23.2
MAXIMUM = 38
PEAKING = 1.64

57D		9	13	14	12		
C		14	17	18	16		
B		16	19	18	19		
A		18	23	20	21		
49	11	16	18	19	16	14	
	18	23	22	25	24	22	
	22	31	29	29	27	30	
	21	37	37	37	37	30	
41	14	20	19	17	20	18	12
	19	22	23	21	24	21	16
	26	29	26	27	I	27	19
	38	35	I	33	33	36	20
33	18	18	17	16	18	17	14
	24	22	17	I	21	22	18
	26	27	26	30	27	27	18
	35	35	I	38	34	36	17
25	16	20	18	17	20	19	14
	21	24	I	24	26	21	17
	27	30	I	30	30	28	19
	38	35	35	33	34	34	22
17	13	17	19	19	20	15	10
	18	23	20	23	22	21	13
	24	32	26	29	27	30	15
	34	37	I	33	34	35	16
9		14	17	18	16	12	
		19	22	23	20	16	
		25	27	25	26	20	
		33	26	32	36	19	
	8	16	24	32	40	48	56

I = Inoperable LPRM

FIGURE 3
LPRM AXIAL PHASE RELATIONSHIP

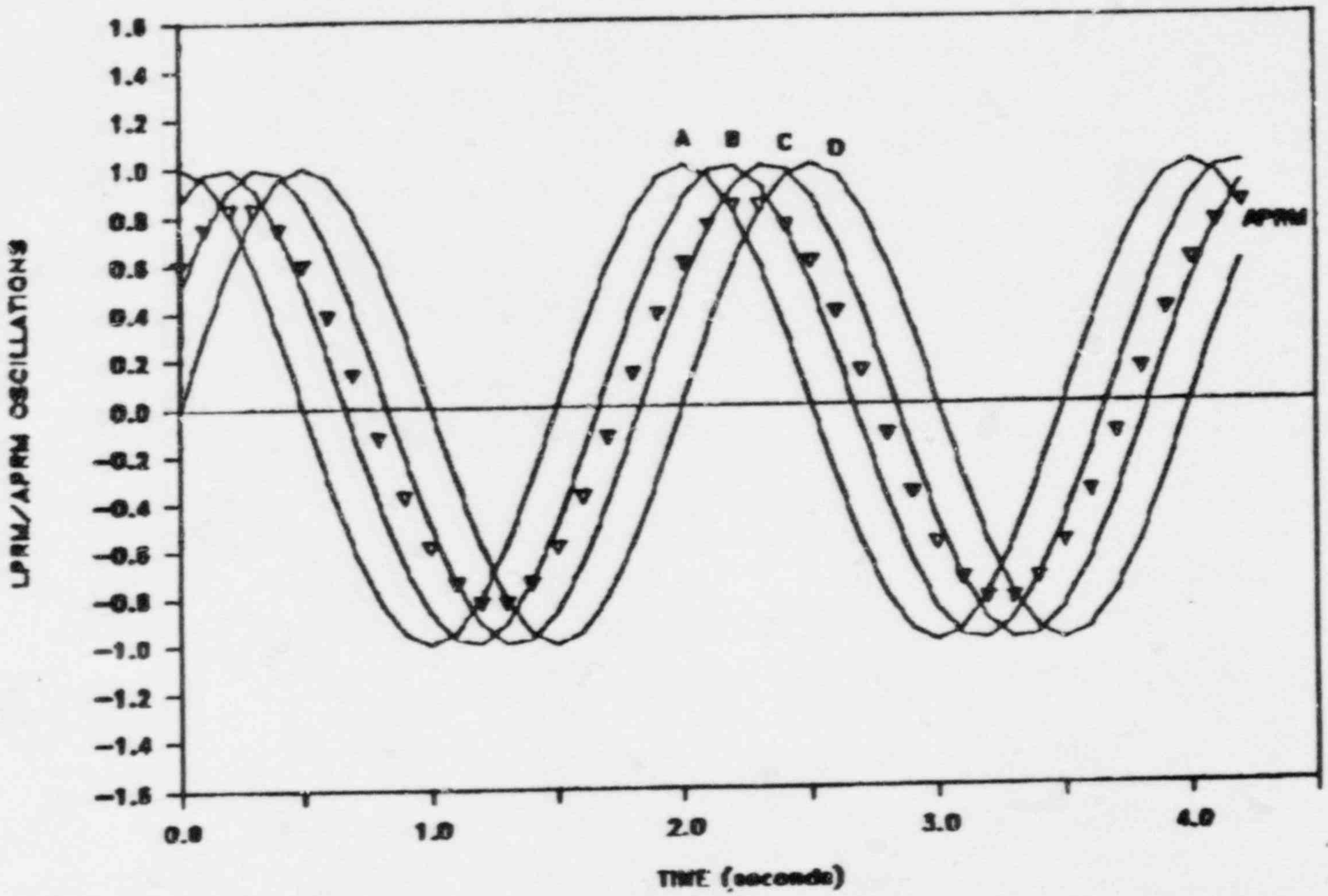
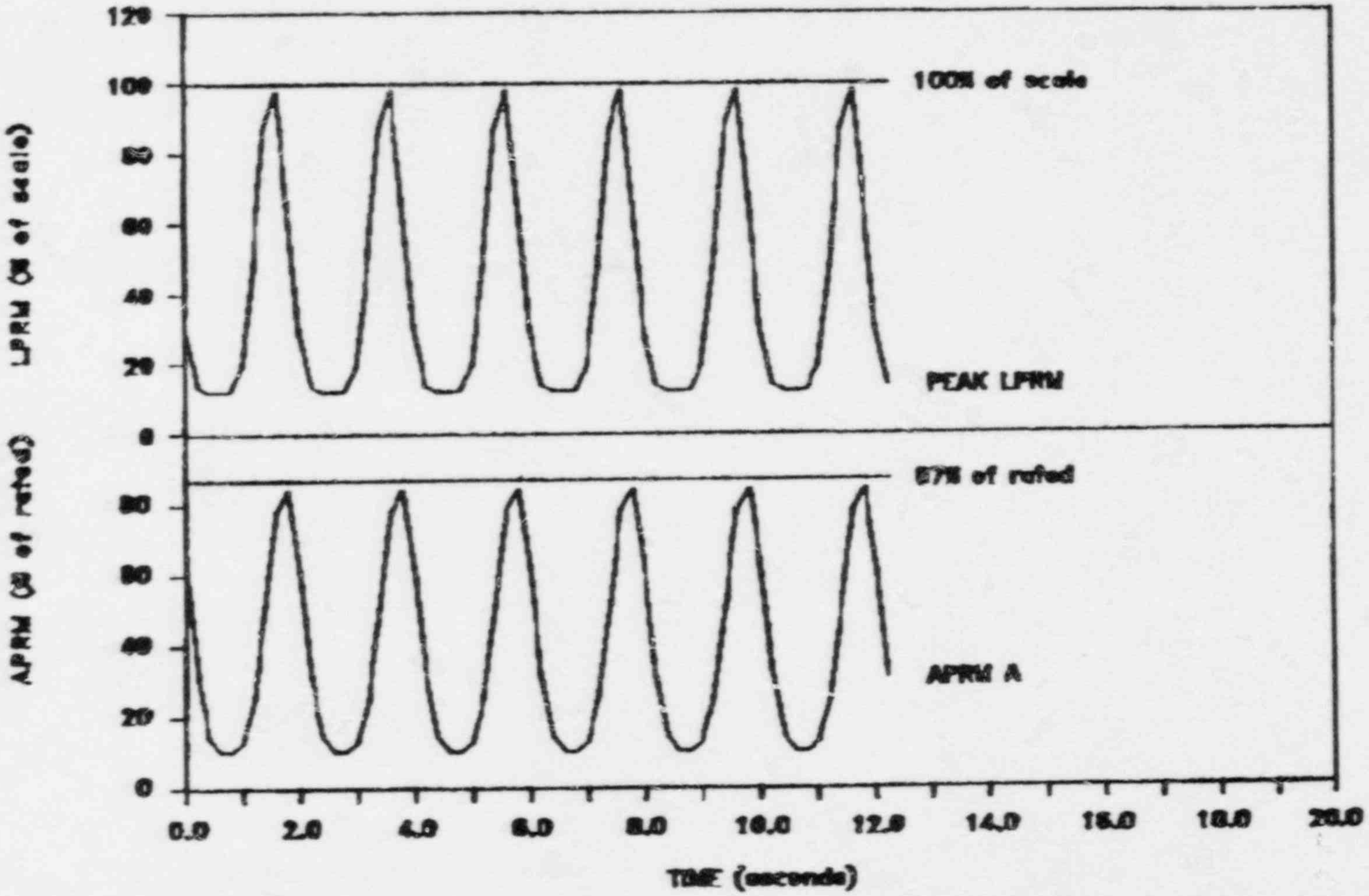


FIGURE 4
LPRM/APRM RESPONSE DURING OSCILLATIONS



February 10, 1984
File Tab A

SIL No. 380
Revision 1
Category 1

BWR CORE THERMAL HYDRAULIC STABILITY

The possibility of thermal hydraulic instability in a BWR has been investigated since the startup of early BWRs. These early tests oscillated a control rod within one notch position and measured the response of the core. For modern higher-power density reactors, pressure pertubation techniques were developed to measure the core stability margins. Based on these tests and analytical models, it has been previously identified (Service Information Letter 380) that the high power/low flow corner of the power/flow map (Figure 1) is the region of least stability margin. This region may be encountered during startup/shutdown, during rod sequence exchanges and as a result of a recirculation pump(s) trip event. Service Information Letter 380 discussed the possibility of increased neutron flux noise and recommended appropriate operator action in the event that neutron flux noise of increased magnitude occurs. As the result of new stability test data, additional information on BWR thermal hydraulic stability has been obtained. As such, this revision of SIL-380 is made to reflect the new information and to provide additional operating recommendations in the unlikely event that thermal hydraulic instability induced neutron flux oscillations occur. This SIL-380, Revision 1, replaces SIL-380 issued August 1982 in its entirety and applies to General Electric BWRs using GE BWR fuel.

DISCUSSION

BWR cores typically operate with the presence of global neutron flux noise in a stable mode which is due to random boiling and flow noise. This noise, although exhibiting a dominant frequency of 0.3 to 0.7 Hz (the natural frequency of the BWR), does not result in sustained limit cycle oscillations since the system is in a stable mode. This occurrence of neutron noise is best characterized by the Average Power Range Monitor (APRM) signal which typically shows neutron flux noise levels of 4-9% (peak-to-peak) at rated power/flow conditions with two recirculation pumps in operation. During single recirculation pump operation (SLO), neutron noise levels of 4-12% of rated (peak-to-peak) have been reported for the range of low to high recirculation pump speed.

As the power/flow conditions are changed, along with other system parameters (pressure, subcooling, power distribution, etc.) the thermal hydraulic/reactor kinetic feedback mechanism can be enhanced such that random perturbations may result in sustained limit cycle oscillations in power and flow at the dominant frequency of 0.3 to 0.7 Hz. These conditions are most likely to occur at the high power/low flow corner of the power/flow map (Figure 1). Previous stability tests at an operating plant demonstrated the occurrence of limit cycle neutron flux oscillations (as seen by the APRM recordings) at the intersection of the rated rod line and natural circulation flow. These oscillations were readily observed on the APRM recorders and were easily suppressed by the insertion of several control rod notches. In addition, examinations of the individual Local Power Range Monitors (LPRM) indicated that all of the LPRMs were oscillating in phase. Recent stability tests at another plant have also demonstrated the occurrence of limit cycle neutron flux oscillations at natural circulation and several percent above the rated rod line. The oscillations were again observable on the APRMs and suppressed by minimal control rod insertion. It was predicted that limit cycle oscillations would occur at the operating state tested; however, the characteristics of the observed oscillations were different than those previously observed at other stability tests. Examination of the detailed test data of these most recent tests showed that some LPRMs oscillated out of phase with the APRM signal and at higher amplitudes than the core average. Although the local oscillations were larger than the core average, very large margin to safety limits was maintained and the oscillations were detectable and easily suppressed by minimal control rod insertion.

Four hundred twenty reactor years of BWR operating experience (including 150 years of high power density plant operation) have demonstrated that instabilities in BWRs are unlikely at or above natural circulation flow rate and below the rated rod line. In addition since these instabilities are a function of power/flow ratio, they are even less likely to occur in the lower power density designs (BWR/2-3). However, the above tests along with limit cycle oscillations that have been encountered at operating reactors at minimum forced circulation above the rated rod line demonstrate that oscillations may occur at unique operating states.

In summary, as demonstrated by tests and operating experience at BWRs, these oscillations are observable on the neutron monitoring system and can be readily suppressed by control rod insertion (or core flow increase if possible). In addition, the most recent tests indicate that local regions may exhibit characteristics different from those of the core average, therefore the operators should follow the recommendations to observe and mitigate limit cycle oscillations should they occur. Because of their low power density design, these recommendations are for "information only" to BWR2-3 operators.

RECOMMENDATIONS

General Electric recommends that BWR operators using GE BWR fuel monitor the inherent neutron flux signals and avoid or control abnormal neutron flux oscillations (with particular attention to the region of sensitivity in Figure 1 where the probability of sustained neutron flux oscillations increases) as follows:

1. Become familiar and aware of your plants normal average power range monitor (APRM) and local power range monitor (LPRM) peak-to-peak neutron flux for all operating regions of the power/flow map and for all operating modes (e.g., two loop and single loop operation). In particular establish an expected APRM and LPRM peak-to-peak signal for your plant at various operating states and also for special operating modes (i.e., SLO) if these modes will be used. The expected APRM noise amplitude can be easily determined from past steady state strip chart recordings or can be established based on current operating conditions.

2. Whenever making APRM or LPRM readings, verify that the neutron flux noise level is normal. If there is any abnormal increase in the neturon flux response follow the recommendations in Section 6d to suppress the abnormal noise signal.

3. The LPRM gains should be properly calibrated as per current plant procedures. This will permit the LPRM upscale alarm trip setpoints to be set as high as full scale while providing appropriate indication against unacceptable reduction in thermal margin because of power oscillations. The LPRM upscale alarm indicators should be regularly monitored and all upscale alarms should be investigated to determine the cause and to assure that local limits are not being exceeded.

4. Whenever changes are made or happen that cause reactor power to change, monitor the power change on the APRMs and locally on the LPRMs surrounding control rod movement to become familiar with the expected neutron flux signal characteristics.

5. If a recirculation pump(s) trip event results in operation in region 1 of Figure 2:

   a. Immediately reduce power by inserting control rods to or below the 80% rod line using the plant's prescribed control rod shutdown insertion sequence.

b. After inserting control rods, frequently monitor the APRMs and monitor the local regions of the core by using the control rod select switch to display the various LPRM strings which surround the selected control rod. A minimum of nine control rods should be selected to adequately display LPRMs representing each octant of the core and the core center (Figure 3). If there is any abnormal increase in the expected signals, insert additional control rods to suppress the oscillations using the plant's prescribed control rod shutdown insertion sequence.

c. After inserting control rods, monitor the LPRM upscale alarm indicators and verify (using recommendation 5b) that any LPRM upscale alarms which are received are not the result of neutron flux limit cycle oscillations.

d. When restarting recirculation pumps (or switching from low to high frequency speed for flow control valve plants), the operation should be performed below the 80% rod line.

e. Once pumps have been restarted and recovery to power is to commence, follow the recommendations in Section 6.

6. When withdrawing control rods during startup in region 2 of Figure 2:

a. Monitor the APRMs and the LPRMs surrounding control rod movement continually as power is being increased or flow is being reduced for any abnormal increase in the normal neutron flux response.

b. Monitor the LPRM upscale alarm indicators and verify (using recommendation 5b) that any LPRM upscale alarms which are received are not the result of neutron flux limit cycle oscillations.

c. Operate the core in as symmetric a mode as possible to avoid asymmetric power distributions. When possible, control rods should be moved in octant (sequence A) and quadrant mirror (sequence B) symmetric patterns. Control rod movement should be restricted to no more than 2 feet at a time and control rods within a symmetric rod group should be within 2 feet of each other at all times. For BWR/6 plants with ganged rod withdrawal, control rods should be moved in gangs as much as possible to maintain symmetric rod patterns.

d. If there is any abnormal increase in the normally expected neutron flux response, the variations should be suppressed. It is suggested that the operation which caused the increase in neutron flux response be reversed, if practical, to accomplish this suppression; control rod insertion or core flow increase (PCIOMR's should be followed during flow increases) will result in moving toward a region of increased stability.

e. An alternative to recommendation 6a-d is to increase core flow such that operating region 2 of Figure 2 is avoided. PCIOMR guidelines should still be followed.

7. When performing control rod sequence exchanges:

a. Follow recommendations 6a-d, or

b. Perform control rod sequence exchanges outside of regions 1 and 2 of Figure 2.

8. When inserting control rods during shutdown, insert control rods to or below the 80% rod line prior to reducing flow into region 2 of Figure 2 (i.e., avoid region 2 during shutdown).

9. Should any abnormal flux oscillations be encountered, data should be recorded on the highest speed equipment available and all available power, flow, power shape, feedwater, pressure and rod pattern information documented for subsequent evaluation and operational guidance.

Prepared by: G.A. Watford

Aproved by: D.L. Allred
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Customer Service Information

Issued by: R.E. Bates
R.E. Bates, Specialist
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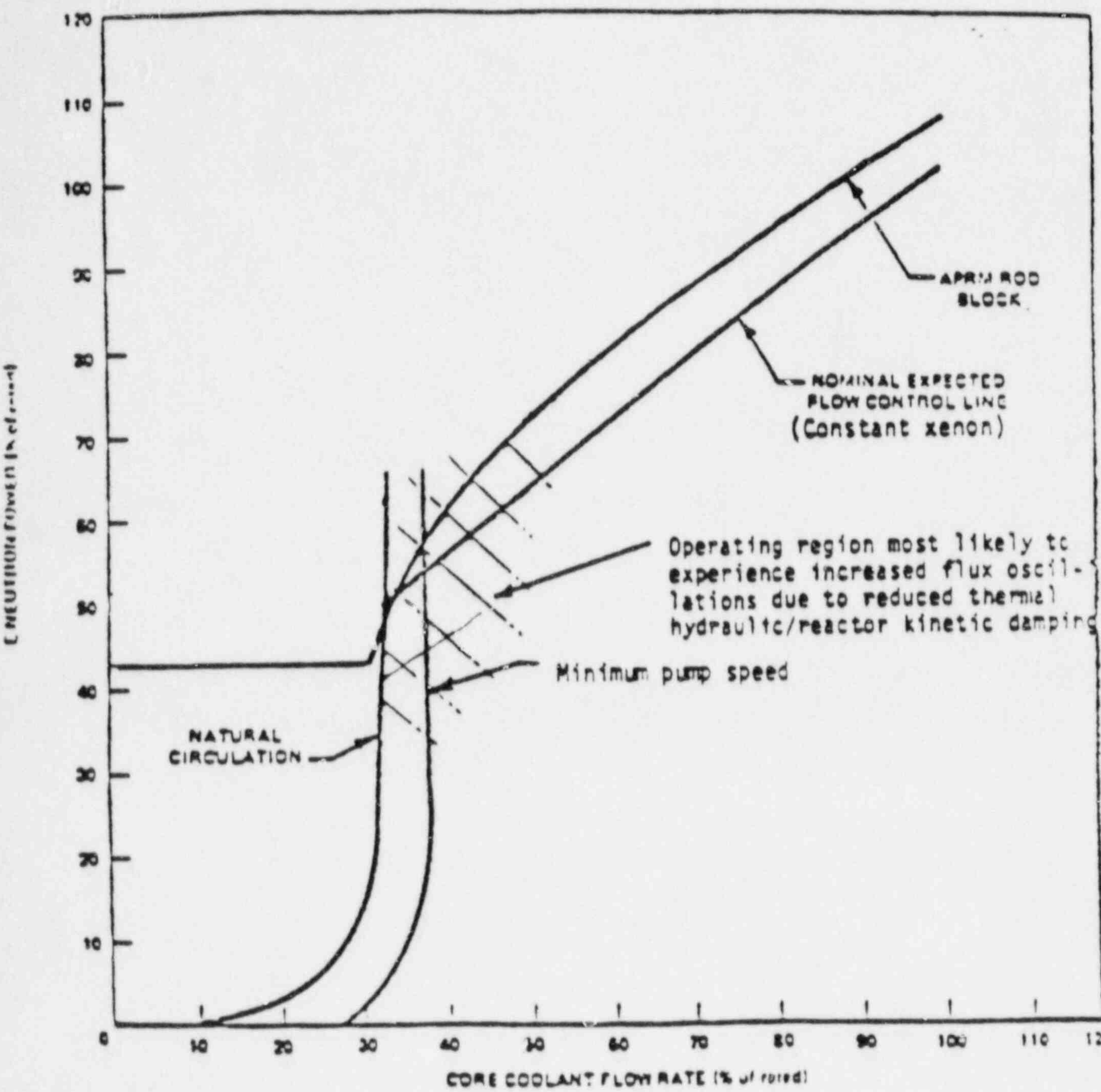
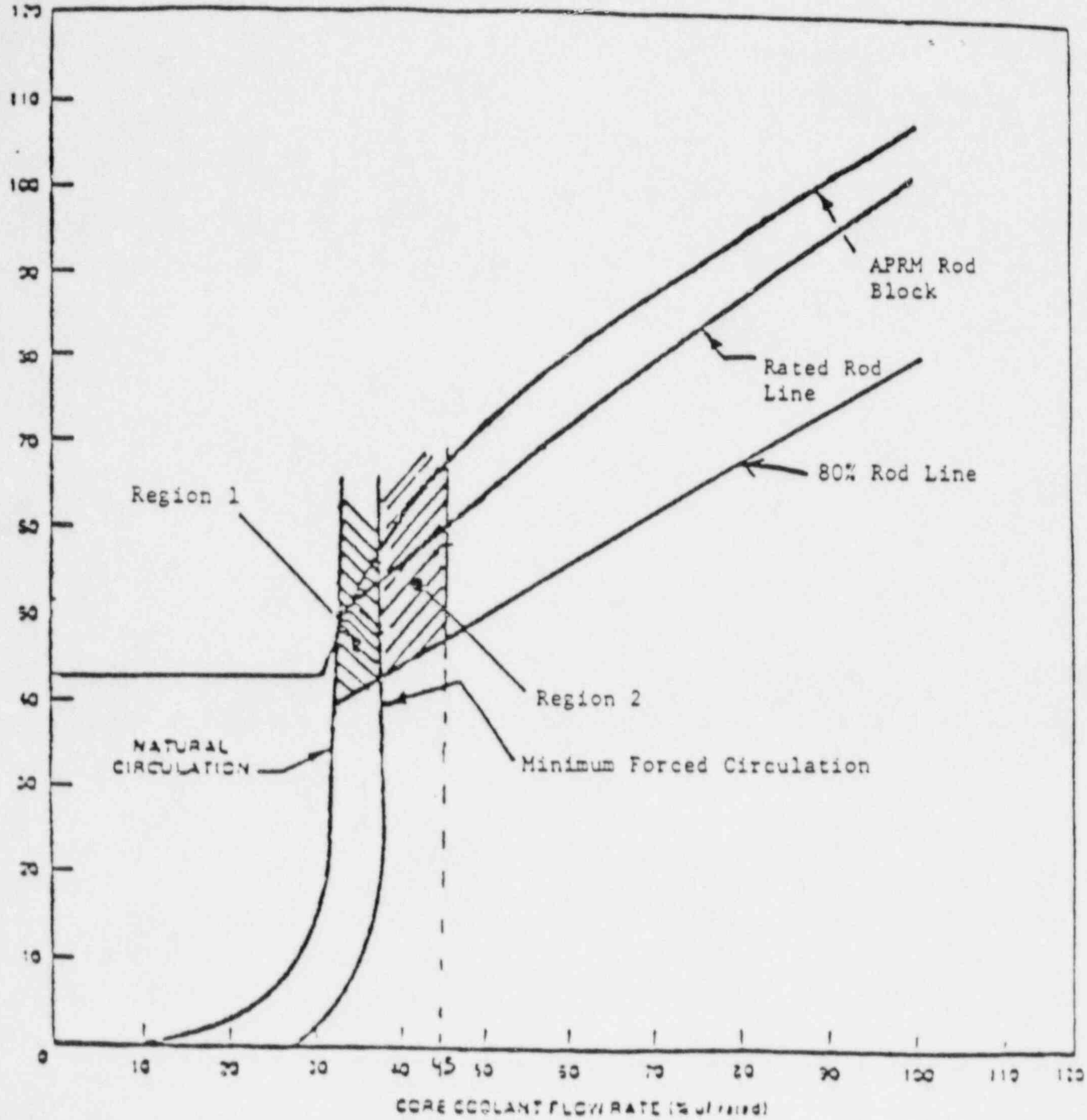
Product Reference: A71 - Plant Recommendations



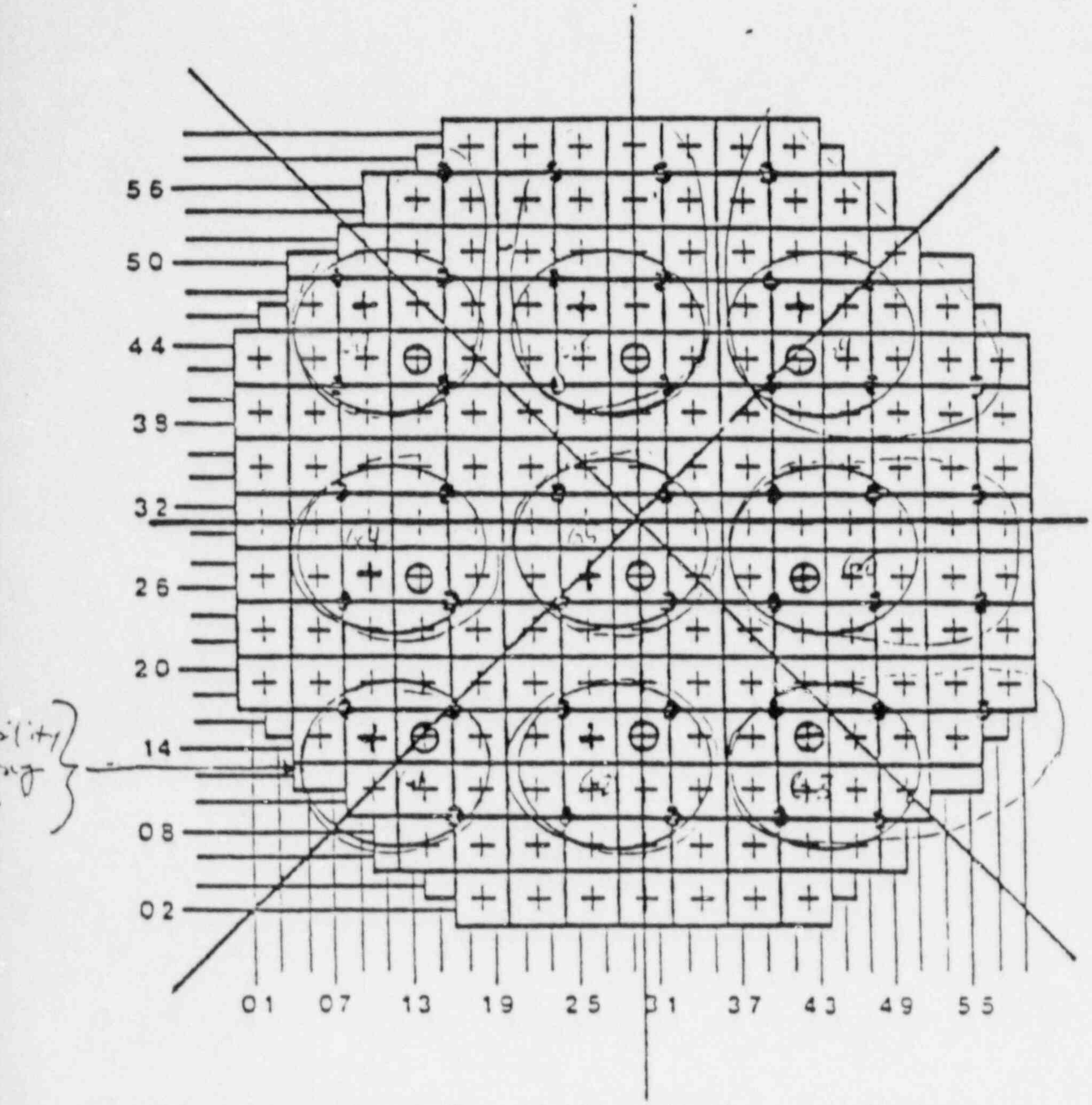
TYPICAL BWR POWER FLOW MAP

FIGURE 1



IDENTIFIED REGIONS OF THE BWR POWER FLOW MAP

Figure 2



Selected Control Rods ⊕

14-15	14-27	14-43
30-15	30-27	30-43
42-15	42-27	42-43

TYPICAL LOCAL REGION MONITORING SCHEME

Figure 3

LICENSEE EVENT REPORT (LER)

Facility Name (1)	Docket Number (2)	Page (3)
LaSalle County Station Unit 2	0 5 0 0 0 3 7 4	1 of 0 5

Title (4) Reactor Scram on High Average Power Range Monitor Flux Level due to the Personnel Valving Error

Event Date (5)			LER Number (6)			Report Date (7)			Other Facilities Involved (8)	
Month	Day	Year	Year	Sequential Number	Revision Number	Month	Day	Year	Facility Names	Docket Number(s)
0 3	0 9	8 8	8 8	0 0 3	0 0	0 4	0 7	8 8		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	1
POWER LEVEL (10)	0 8 4

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10CFR (Check one or more of the following) (11)

	20.402(b)		20.405(c)	X	50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		Other (Specify in Abstract below and in Text)
	20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

Name	Telephone Number: Area Code	
Milton H. Richter, Asst. Technical Staff Supervisor, ext. 259	8 1 5	3 5 7 - 6 7 6 1

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
A	B N			N					
D				N					

SUPPLEMENTAL REPORT EXPECTED (14)

		Expected Submission Date (15)	Month	Day	Year
Yes (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

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

At 1732 hours on March 9, 1988, with Unit 2 in Operational Condition 1 (Run) at approximately 84% power, a valving error during an instrument surveillance caused the Reactor Recirculation (RR) pumps to trip off. This caused a large and rapid power reduction to approximately 40% power. While trying to stabilize the feedwater heaters and restart a RR pump, the Average Power Range Monitors (APRMs) were observed to be oscillating between 25-50% power (25% peak-to-peak). As preparations were being made to manually scram the reactor, an automatic scram occurred on APRM neutron flux high (118% trip) at 1739 hours. The scram was caused by neutron flux oscillations experienced while the unit was at a high rod line and low flow (natural circulation) condition.

The root cause of this event was personnel error for the initial transient, and procedural inadequacy for the scram. Although operating personnel were cognizant of the potential for (and observed) neutron flux oscillations, the operating procedures did not provide sufficient guidance for prevention/suppression of oscillations. The neutron flux oscillations seen by the APRMs and Local Power Range Monitors were occurring "in phase" across the core and were bounded by the APRM high neutron flux scram (118%).

Operating procedures were revised to ensure prompt action (as recommended by General Electric SIL 380, Rev. 1) when the unit is operating at a condition which is susceptible to neutron flux oscillations. In addition, as a temporary measure, a Confirmatory Action Letter issued by NRC Region III requires the plant to be scrammed (manual) immediately in the event of a dual pump (RR) trip.

This event is reportable pursuant to the requirements of 10CFR50.73(a)(2)(iv) due to the automatic actuation of the Reactor Protection System.

8804140177 6pp

PLANT AND SYSTEM IDENTIFICATION

General Electric - Boiling Water Reactor

Energy Industry Identification System (EIIS) codes are identified in the text as [XX].

A. CONDITION PRIOR TO EVENT

Unit(s): 2 Event Date: 3/9/88 Event Time: 1739 hours

Reactor Mode(s): 1 Mode(s) Name: Run Power Level(s): 84%

B. DESCRIPTION OF EVENT

At 1739 hours on March 9, 1988, Unit 2 scrammed (automatic) on neutron flux high (118% trip) from the Average Power Range Monitors (APRMs, NR) [IG] due to neutron flux oscillations. The neutron flux oscillations occurred while the unit was at a low flow (natural circulation) and high rod line condition following the trip of the Reactor Recirculation (RR) [AD] pumps.

At 1732 hours, with Unit 2 in Operational Condition 1 (Run) at approximately 84% power (930 MWe), the Instrument Maintenance (IM) Department was performing a surveillance (functional test) on Differential Pressure Switch DPS-2B21-N037BB. This switch supplies a Reactor Core Isolation Cooling (RCIC, RI) [BN] initiation at reactor vessel level 2 (-50 inches). At this time, the "A" Turbine Driven Reactor Feedwater Pump and Motor Driven Reactor Feedwater Pump were operating in three-element control, and feedwater level control (FW) [JK] was selected to channel "B" (which utilizes the same instrument reference leg as DPS-2B21-N037BB). In addition, there were two (2) Nuclear Station Operators (NSO's, licensed RO's) in the Unit 2 control room at this time.

Locally at DPS-2B21-N037BB, the IM technician had successfully isolated the switch (the variable and reference leg isolation valves were closed and the equalizing valve was open) in accordance with the surveillance procedure. While attempting to vent the switch prior to installation of the test equipment, the technician inadvertently opened the variable and reference leg isolation valves instead of the vent/test valves. This initiated a "pressure equalization" between the variable and reference legs, and resulted in a high "indicated" reactor water level to feedwater level control. The high "indicated" level to feedwater level control caused the feedwater pumps to begin slowly reducing flow. In addition, a high reactor water level alarm (level 7, +40.5 inches) was received in the control room which prompted one NSO to monitor feedwater level control.

A second IM technician, who was observing the surveillance locally, notified the primary technician of the valving error, and the variable and reference leg isolation valves were immediately closed (the valving error existed for approximately 15 seconds). The isolation of the reference leg from the variable leg resulted in a low "indicated" level spike. From level switches which utilize the same reference leg as DPS-2B21-N037BB, the level spike caused the following to occur;

B. DESCRIPTION OF EVENT (CONTINUED)

- both RR pumps received an ATWS level 2 signal, causing the RR pumps to trip off (per design), and
- channel B-1 of the Reactor Protection System (RPS, RP) [JC] received a level 3 (+12.5 inches) signal for low reactor water level, causing a half scram condition.

The half scram signal was reset upon verification that "actual" reactor water level was not low.

Due to the large and rapid power reduction (following the trip of the RR pumps the unit was at approximately 40% power), feedwater heater high level alarms were received and heaters began isolating (steam side). While one NSO monitored feedwater level control, which was adequately handling the transient ("B" level control channel had stabilized following the initial spike caused by the closure of the isolation valves), the attention of the second NSO was on re-establishing heaters (by opening the extraction steam valves) and preparing for the restart of the RR pumps (as directed by the operating procedure for loss of recirculation flow).

Approximately 5 minutes into the event, Local Power Range Monitor (LPRM, NR) [IG] downscale alarms began annunciating and the APRMs were observed to be oscillating between 25% and 50% power (25% peak-to-peak) with an approximate 2 second period. Cognizant of the unit's location on the power-to-flow map (region susceptible to neutron flux oscillations), operating personnel were attempting to start one RR pump to re-establish recirculation flow and restore stability. If the pump start attempt was unsuccessful, an manual scram of the reactor was planned. After positioning the "A" RR flow control valve for pump restart, two unsuccessful start attempts were made on the "A" RR pump. As shift personnel were preparing to manually scram the unit, an automatic scram occurred on APRM neutron flux high (118% trip) at 1739 hours.

This event is reportable pursuant to the requirements of 10CFR50.73(a)(2)(iv) due to the automatic actuation of the Reactor Protection System.

C. APPARENT CAUSE OF EVENT

The root cause of this event was personnel error for the initial transient, and procedural inadequacy for the scram.

The initiating transient (trip of the RR pumps) was caused by a valving error (by an IM technician) during the surveillance on DPS-2B21-N037BB. The low "indicated" level spike which occurred during correction of the valving error resulted in tripping the RR pumps and placing the unit in a natural circulation condition.

C. APPARENT CAUSE OF EVENT (CONTINUED)

The scram was caused by neutron flux oscillations experienced while the unit was at a high rod line (high power) and low flow (natural circulation) condition. This condition (high rod line and low flow) has previously been identified by General Electric to be susceptible to neutron flux oscillations (core thermal hydraulic instabilities). The operating procedure for loss of recirculation flow (two pump trip) did not include the insertion of control rods (power rods) as an immediate corrective action. The insertion of power rods would have reduced rod line which is a recommended corrective action to prevent/suppress neutron flux oscillations. Operating personnel response for this event was found to be consistent with station procedures. The operating personnel were cognizant of the potential for (and observed)(neutron flux oscillations, however, the operating procedures for this event did not provide sufficient guidance for prevention/suppression of oscillations.

The exact cause for the inability to start the "A" RR pump could not be determined, however, it is believed that a pump start permissive was not satisfied. The RR pump start circuitry contains numerous interlocks/permissives which need to be satisfied to achieve a successful pump start. Following the scram, the suspect permissive was no longer required for pump start, and a successful pump start occurred. At this time, the control room operator has no indication which verifies that the RR pump start permissives are satisfied.

D. SAFETY ANALYSIS OF EVENT

A review of this event determined that the neutron flux oscillations, seen by the APRM's and LPRM's, were occurring "in phase" across the core and were bounded by the APRM high neutron flux scram (118%) which automatically terminated the event. The frequency and magnitude of the oscillations experienced were consistent with the characteristics observed during stability testing and operation at other Boiling Water Reactors (BWR's). Previous analyses have demonstrated that the oscillations in neutron flux observed during this event do not result in exceeding fuel thermal and mechanical safety and design limits. Therefore, the neutron flux oscillations in this event did not adversely affect any safety system or the safe operation of the plant.

E. CORRECTIVE ACTIONS

This event was reviewed with General Electric and Commonwealth Edison's Nuclear Fuel Services Department.

The IM personnel involved in this event have been counseled.

This event has been reviewed with all IM Department personnel.

Operating Department personnel have reviewed this event through shift briefings.

E. CORRECTIVE ACTIONS (CONTINUED)

Operating procedures have been reviewed and revised to ensure prompt and proper action when the unit is operating at a condition which is susceptible to neutron flux oscillations. The procedure revisions incorporated the recommendations provided by General Electric in Service Information Letter (SIL) 380, Revision 1 (BWR Core Thermal Hydraulic Stability), with particular emphasis on the immediate insertion of control (power) rods upon the loss of a RR pump(s) at greater than the 80% flow control line.

In accordance with a Confirmatory Action Letter issued by the Nuclear Regulatory Commission (Region III), the unit will be manually scrammed upon the loss of both RR pumps. This is a temporary measure and is being controlled by an Operating Department special order (88-21).

During the startup of the unit, chemistry sampling (reactor water and off gas) occurred at an increased frequency to verify the integrity of the fuel. No indication of any fuel problems were found from this sampling.

Since the onset of neutron flux oscillations occurred in approximately five (5) minutes during this event, amendments to the station's Technical Specifications are being submitted which will require prompt initiation of corrective action when the unit is operating at a condition which is susceptible to neutron flux oscillations. Action Item Record (AIR) 374-200-88-01801 will track this item.

A discussion on this event, and the Operating procedure revisions which resulted from this event, will be presented to all licensed Operating personnel at the next scheduled Operator training session. AIR 374-200-88-01802 will track completion of this item.

A modification is being considered which would install a pump permissive indicating light for each RR pump. The light will provide indication for prompt assessment of the status of the pump permissives. AIR 374-200-88-01803 will track the completion of this item.

At this time, Commonwealth Edison's Production Training Department is investigating the ability to remodel the LaSalle simulator for this type of an event to enhance operator training. AIR 374-200-88-01804 will track this item.

F. PREVIOUS EVENTS

None.

G. COMPONENT FAILURE DATA

None.

Commonwealth Edison
LaSalle County Nuclear Station
Rural Route #1, Box 220
Marseilles, Illinois 61341
Telephone 815/357-6761

April 7, 1988

U. S. Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555

Dear Sir:

Licensee Event Report #88-003-00, Docket #050-374 is being submitted to your office in accordance with 10CFR50.73(a)(2)(iv).

WRoAmt
G. J. Diederich
for Station Manager
LaSalle County Station

GJD/MHR/kg

Enclosure

xc: Nuclear Licensing Administrator
NRC Resident Inspector
NRC Region III Administrator
INPO - Records Center

Attachment 6
APR 12 1988

DCD

MAY 1 6 1988

Docket No. 50-373
Docket No. 50-374

Commonwealth Edison Company
ATTN: Mr. Cordell Reed
Senior Vice President
Post Office Box 767
Chicago, IL 60690

Gentlemen:

The enclosed report refers to the special onsite review conducted by the NRC Augmented Inspectic. Team (M. A. Ring, B. A. Azab, R. A. Kopriva, of this office, and L. E. Phillips and P. Shemanski from NRR) on March 16 through 24, 1988. The review was in response to the recent dual recirculation pump trip and subsequent core flux oscillations resulting in a reactor trip on March 9, 1988, at the LaSalle County Station Unit 2, authorized by Operating License No. NPF-18. The essence of our findings were discussed with Messrs. D. Galle, G. Diederich and others of your staff at the conclusion of the inspection.

The enclosed copy of our inspection report identifies areas examined during the inspection. Within these areas, the inspection consisted of a selective examination of procedures and representative records, observations, and interviews with personnel.

The major purpose of the Augmented Inspection Team (AIT) was to perform onsite fact finding regarding the event. Issues identified by the AIT may be examined for possible regulatory violations in subsequent inspections.

In accordance with 10 CFR 2.790 of the Commission's regulations, a copy of this letter and the enclosed inspection report will be placed in the NRC Public Document Room.

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We will gladly discuss any questions you have concerning this inspection.

Sincerely,

ORIGINAL SIGNED BY E. G. GREENMAN

Edward G. Greenman, Director
Division of Reactor Projects

Enclosure: Augmented Inspection
Report No. 50-373/88008(DRP);
50-374/88008(DRP)

cc w/enclosure:
H. Bliss, Nuclear
Licensing Manager
G. J. Diederich, Plant Manager
DCD/DCB (RIDS)
Licensing Fee Management Branch
Resident Inspector, RIII
Richard Hubbard
J. W. McCaffrey, Chief, Public
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E. Jordan, AEOD
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R. L. Spessard, AEOD
W. Kane, RI
L. Reyes, RII
J. Callen, RIV
D. Kirsch, RV
Resident Inspector, Dresden
Resident Inspector, Quad Cities
D. Jones, Project Inspector

YES	YES	YES	YES	YES		
RIII	RIII	RIII	RIII	NRR	NRR	RIII	RIII
Kopriva/jp	Azab	Ring 5/6/88	Phillips 5/11/88	Shemanski 5/11/88	Forney 5/11/88	Greenman 5/13/88

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-373/88008; 50-374/88008

Docket No. 50-373; 50-374 License No. NPF-11; NPF-18

Licensee: Commonwealth Edison Company
P. O. Box 767
Chicago, IL 60690

Facility Name: LaSalle County Station, Units 1 and 2

Inspection At: LaSalle Site, Marseilles, IL

Inspection Conducted: March 16 through 24, 1988

Inspectors: NRC Augmented Inspection Team

Team Leader: M. A. Ring M A Ring 5/11/88
Date

Team Members: R. A. Kopriva M A Ring for 5/6/88
Date

L. E. Phillips M A Ring for 5/11/88
Date

P. Shemanski M A Ring for 5/11/88
Date

B. A. Azab M A Ring for 5/6/88
Date

Approved By: W. L. Forney, Chief for 5/11/88
Reactor Projects Branch 1
Date

Inspection Summary

Inspection on March 16 through 24, 1988 (Report No. 50-373/88008(DRP); 50-374/88008(DRP))

Areas Inspected: Special Augmented Inspection Team (AIT) inspection conducted in response to the dual recirculation pump trip and subsequent core power

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oscillations resulting in a reactor trip on March 9, 1988, at LaSalle, Unit 2. The review included root cause determination, safety significance, performance of operators and equipment, adequacy of procedures, effects on the reactor, reporting actions and potential generic implications.
Results: No violations or deviations were identified; however, the licensee has committed to procedure and Technical Specification changes as well as further study in the areas of inherent shutdown mechanisms, instrumentation capability and uncertainties in the decay ratio calculations. The licensee's interim report, as required by the CAL, is included as attachment 5 to this report.

Augmented Inspection Team Report

Page No.

Attachments

Attachment No.	Description
1	Confirmatory Action Letter (CAL-RIII-88-03)
2	Augmented Inspection Team (AIT) Charter
3	Figures
Figure 1	BWR Power to Flow Map
Figure 2	Decay Ratio
Figure 3	Startrec Traces - Beginning of Event
Figure 4	Startrec Traces - Oscillations
4.	Technical Specifications
5	Commonwealth Edison Company (CECo) Response to CAL item 5, dated April 15, 1988
6	LER 88-003-00
7.	GE SIL 380

I. INTRODUCTION

A. Synopsis of Event

On Wednesday, March 9, 1988, around 5:30 p.m. CST, the LaSalle Unit 2 reactor was operating at steady state conditions at approximately 84% power. Instrument Maintenance Department personnel were in the process of performing an instrument surveillance when a valving error produced a pressure pulse which actuated the instrumentation which causes a trip of both recirculation (RR) pumps in order to decrease power in the event of an Anticipated Transient Without Scram (ATWS). Both RR pumps tripped causing a flow and power decrease. Control rods remained in the high power (99% Flow Control Line (FCL)) position. As a result of the rapid power decrease caused by the trip of the RR pumps, the feedwater heater level control system was unable to control level in the feedwater heaters and began isolating extraction steam from the heaters. This resulted in cooler feedwater being supplied to the reactor. Approximately five minutes after the RR pump trip, operators observed the Average Power Range Monitor (APRM) indication in the control room to be oscillating between 25% and 50% power every 2 to 3 seconds. Approximately seven minutes after the RR pump trip, as operators were attempting to restore forced flow and making preparations to scram, the reactor automatically scrammed on high neutron flux as seen by the APRMs. At 6:32 p.m. CST, the licensee notified the NRC of the RR pump trip, the loss of feedwater heating, and the resultant scram.

B. AIT Formation

At the time of the event on March 9, 1988, the Resident Inspector assigned to LaSalle was offsite attending the Resident Seminar and the Senior Resident Inspector position for LaSalle was vacant due to a recent promotion. The initial licensee report on the event did not discuss the flux oscillations but indicated that the event was still being investigated. Upon further investigation and appreciation of the magnitude of the oscillations a Region III morning report update of the event was issued on March 15, 1988. On March 16, 1988, an Augmented Inspection Team (AIT) was formed which included three Region III individuals; M. A. Ring, Chief, Reactor Projects Section 1B and Team Leader, R. A. Kopriva, LaSalle Resident Inspector, and B. A. Azab, Reactor Safety Inspector, and two NRR individuals; L. E. Phillips, Senior Nuclear Engineer, and P. Shemanski, LaSalle Project Manager. All of the AIT members had arrived onsite by the morning of March 17, 1988. Concurrent with the AIT activities, Region III issued a Confirmatory Action Letter (CAL-RIII-88-03) which was received by the licensee on March 17, 1988, and is included as Attachment 1 to this report. The CAL confirmed certain actions to be taken by the licensee in support of the AIT and established conditions to be met prior to the restart of LaSalle, Unit 2.

C. AIT Charter

On March 17, 1988, a draft charter for the AIT was formulated and transmitted to the AIT onsite (Attachment 2 to this report). The general areas to be investigated were:

- Sequence of events
- Core performance during the event
- Operator performance
- Procedure adequacy
- Reactor effects
- Reporting

D. Persons Contacted

Commonwealth Edison Company

*G. J. Diederich, Station Manager
*N. Kalivianakis, General Manager, BWR Operations
*D. Galle, Vice President, BWR Operations
*H. E. Bliss, Manager of Nuclear Licensing
*W. R. Huntington, Services Superintendent
*T. Rausch, Nuclear Fuel Services
*W. F. Naughton, Nuclear Fuel Services Manager
*M. Turbak, Assistant Licensing Manager
*J. Bitel, Manager Nuclear Safety
*R. J. Raguse, Production Training Supervisor
*T. Shaffer, Training Supervisor
*R. O. Armitage, Lead License Instructor
*K. W. Peterman, Nuclear Fuel Services
*L. H. Lauterbach, Onsite Nuclear Safety Supervisor
*H. McLain, Onsite Nuclear Safety
*W. S. Marcus, Engineering-Site Supervisor
*J. C. Renwick, Production Superintendent
*J. A. Miller, Technical Staff
*M. H. Richter, Assistant Technical Staff Supervisor
*G. A. Brown, Quality Assurance Superintendent
*P. F. Manning, Assistant Superintendent - Technical Services
*T. A. Hammerich, Technical Staff Supervisor
*A. C. Settles, Regulatory Assurance
B. S. Westphal, Operating Engineer
R. W. Stobert, Director of Quality Assurance Operations
J. A. Silady, Nuclear Licensing
M. Wagner, Dresden Nuclear Group
M. G. Santic, Master Instrument Engineer
L. W. Raney, Nuclear Safety Braidwood
R. Weidner, Production Training
J. Dedin, Production Training
R. Graham, Nuclear Station Operator
E. McVey, Technical Staff

General Electric Company (GE)

H. Pfefferlen, Licensing
G. A. Watford, Engineering

*Denotes those attending the exit meeting on March 24, 1988.

In addition, several other members of the LaSalle staff were contacted by the AIT.

II. DESCRIPTION - DUAL RECIRCULATION PUMP TRIP EVENT OF MARCH 9, 1988

A. Narrative Description

On Wednesday, March 9, 1988, around 5:32 p.m. CST, the LaSalle Unit 2 reactor was operating at steady state conditions at approximately 84% power with 76% rated core flow using both recirculation (RR) pumps and with the control rods withdrawn to the 99% flow control line. Feedwater temperature was 402°F. LaSalle Unit 1 was operating at power in steady state conditions and was unaffected by the subsequent events on Unit 2. Instrument Maintenance Technicians (IMs) were in the process of performing a surveillance test on Wide Range level instrument 2B21-N037BB to check the Reactor Core Isolation Cooling (RCIC) initiation function at -50 inches reactor level. The IMs were stationed at the instrument rack and in the control room and had received permission from the appropriate operations personnel to perform the surveillance. The IM at the instrument rack had correctly isolated and equalized the instrument (2B21-N037BB) in accordance with the functional test procedure, LIS-NB-404. The next action was to open the test/vent valves, however, instead the IM technician opened the isolation valves to the variable and reference legs to the instrument. Since the equalizing valve was still open, a pressure equalization occurred between the variable and reference legs for this instrument and all the other instruments which share the same reference leg. At the time of the valving error feedwater level control was selected to channel B which takes input from an instrument which utilizes the same reference leg as 2B21-N037BB. The equalization produced by the valving error resulted in a high "indicated" level to feedwater level control, causing the operating feedwater pumps (A turbine driven reactor feedwater pump - TDRFP, and the motor driven reactor feedwater pump - MDRFP) to begin reducing flow. The IMs realized a valving error had been made and attempted to correct the error by shutting the reference and variable leg isolation valves. This action caused a pressure pulse on the reference leg of all the instruments which share the same reference leg at that instrument rack. Increasing pressure on the reference leg caused the level instruments to indicate low reactor vessel level. The key instruments which were affected by this pulse were the ATWS RR pump trip switches 2B21-N036C and 2B21-N036D, which are designed to trip the A and B RR pumps to off. Both RR pumps did, in fact, trip off. Instrument 2B21-N024B which provides a reactor protection system

(RPS) channel B1 low level 1/2 scram was also affected and resulted in a 1/2 scram signal and the associated alarm.

The trip of the RR pumps resulted in a large and rapid power reduction (approximately 45%) as a result of the large flow reduction (to natural circulation conditions). The control rods remained in their pre-RR pump trip position on the 99% control line (see Attachment No. 3-BWR Power to Flow Map). This region of the BWR Power to Flow Map was known to be susceptible to instabilities in some BWRs. As a result of the large drop in power, a large drop in steam flow occurred causing large changes in extraction steam flow and extraction steam pressure. Extraction steam supplies the heating to the feedwater heaters. The changes in extraction steam caused severe perturbations in the feedwater heater level control system due to water flashing to steam from lower shell pressures, reductions in shell side input from reduced steam flow, and changes in condensing rate. The feedwater heater level control was unable to react fast enough to control the large load reduction and tripped the extraction steam input to the heaters in order to prevent induction of water into the main turbine. The securing of steam heating to the feedwater heaters resulted in cooler feedwater being supplied to the reactor (approximately 45°F decrease in 4 minutes) which is the equivalent of a positive reactivity addition. This resulted in an increased power to flow ratio which further reduced the margin to instability.

At this point in the event, the operators in the control room were primarily concerned with attempting to restore feedwater heaters. The operators had correctly determined that an ATWS event had not occurred but that an instrument problem had resulted in the loss of both RR pumps. The loss of feedwater heating was not unexpected for the large power drop caused by the RR pump trip. The operators also realized that the reactor was operating in a region of the power to flow map where instability was possible. Between 4 and 5 minutes into the event, the Average Power Range Monitor (APRM) indications were observed by the operators to be oscillating between 25% power and 50% power every 2 to 3 seconds and the Local Power Range Monitor (LPRM) down scale alarms began to annunicate and clear. (Later examination of the STARTREC, Startup Transient Recorder, (a high speed, multi-channel recording system installed for startup testing which starts recording when selected parameters exceed predetermined limits) showed the oscillations to be much larger than the operators were able to see). The APRM indications confirmed the onset of instabilities and the operators attempted to restart a RR pump in order to increase flow to leave the instability region. Attempts to start a RR pump were unsuccessful and the shift commenced preparations to manually scram the reactor. About 7 minutes into the event and before the shift was able to perform a manual scram, the reactor automatically scrammed on high neutron flux as seen by the APRMs. The scram shutdown the reactor as designed and recovery from the scram proceeded normally. Some minor equipment problems occurred during recovery and subsequent cold shutdown, however, these were judged by the AIT to have no effect on the event and will not be discussed further in this report. The licensee informed the NRC at 6:32 p.m. CST of the RR pump loss, feedwater heating loss and resultant scram.

B. Sequence of Events

Times and sequences of events in the previous narrative description were derived by the AIT from a combination of interviews and hard data. The following sequence of events represents a compilation of information by the AIT taken from the alarm printer, the Startrec recording system and interviews with licensee personnel. Times are given in 24 hour clock time (17:32 equals 5:32 p.m.) and are all Central Standard Time.

SEQUENCE OF FVENTS FOR MARCH 9, 1988
LASALLE UNIT 2 INSTABILITY EVENT

Initial Conditions

- 84% Reactor Power (930 MWe)
- Steady State Conditions
- 99% Flow Control Line
- 76% Rated Core Flow (82 x 10^6 lb/hr)
- Feedwater Temperature = 402°F
- LIS-NB-404 in process (Surveillance that tests RCIC initiation at -50" reactor water level.)

Event Summary

March 9, 1988

Time	Event
17:32 (approximately)	Instrument Maintenance Technician valved in the variable and reference legs of a differential pressure switch with the equalizing valve open; initiating a pressure equalization between the two legs and a high "indicated" reactor level.
17:32:33	High Reactor Water Level Alarm initiated.
	STARTREC (Startup Transient Recorder) initiated on increase in narrow range level and ran for programmed 1 minute duration.
*	Instrument Maintenance Technician corrected valving error by isolating reference leg from variable leg which resulted in a low "indicated" level spike causing other instrumentation to actuate.

17:32:49	2A/2B ATWS alarm initiated a trip of both Reactor Recirculation (RR) pumps and power and flow began coasting down to natural circulation levels. Division 2 Reactor Low Level Alarm initiated.
	2A ATWS cleared.
17:32:50	Half scram on +12.5" reactor water level initiated.
	2B ATWS cleared.
	Division 2 Reactor Lo Level Alarm cleared.
	Reactor Water Level 3 Alarm (+12.5") initiated.
17:32:51	Reactor Water Level 3 Alarm cleared.
	Reactor Water Level Hi Channel B trip.
17:32:52	Reactor Water Level Hi Channel B was manually reset.
*	Half Primary Containment Isolation System (PCIS) level trip was manually reset.
	Nuclear Station Operator (NSO) saw that B narrow range reactor water level indicator was approximately 30" and rising while A and C were steady at approximately 40".
17:33:10	First feedwater heater high level alarm annunciated.
17:33:20	First feedwater heater isolates. Feedwater heaters continue to isolate for duration of event.
*	Unit 2 NSO reviewed feedwater heater situation and planned to reopen extraction steam valves after valves fully closed to regain feedwater heating.
	Shift foreman discharged to local heater controllers to aid in reestablishing feedwater heating.
17:36(approximately)	Shift engineer entered control room.
	Operators observed APRMS oscillating between 25% and 50% power with an approximate 2-3 second period.

*	Operators attempted to restart the RR pumps per abnormal operating procedure, LOA-RR-07.
17:36:55	B RR flow control valve locked up.
*	Equipment Operator discharged to reset the lockouts on flow control valves.
17:37:21	First LPRM downscale alarm annunciated. The LPRM downscale alarms continued to flash and clear, on a 2 second period.
17:37:51	First LPRM Hi Alarm annunciated.
17:38:20	The A flow control valve was reset.
	STARTREC initiated on increase in narrow range level and ran for 1 minute.
*	NSO ramped the A flow control valve to minimum position.
17:39(approximately)	NSO attempted restart of 2A RR pump twice, but was unsuccessful.
*	Shift Engineer directed a manual scram to be initiated.
17:39:19	STARTREC terminated its second 1 minute run.
17:39:23	Channel A neutron APRM trip.
17:39:25	Channel B neutron APRM trip.
	Reactor scrammed on 118% neutron flux.

NOTE: * Designates that no Hathaway Recorder time was available for the event. However, the event is listed in the approximate sequence in which it occurred.

III. INVESTIGATIVE EFFORTS

A. Synopsis of AIT Activities

The AIT members had all arrived onsite on March 17, 1988, and were thoroughly briefed on the event by the licensee and General Electric personnel in a meeting at the site at 1:00 p.m. hours on March 17. The team was provided with pertinent instrument records of the event (including Sequence of Events data), and with documentation comprising the safety evaluation by the licensee. The latter included correspondence between the licensee and the reactor vendor (GE). In response to a team request, the licensee also provided a written description of the operator response and assessment of the event as it occurred.

The inspection team had various meetings with the LaSalle plant management and staff and with GE supporting staff during the assessment of the event. Subsequent to telephone conferences with Headquarters and Region III offices, the plant was allowed to restart at approximately 10:45 p.m. on March 17. Operation was to be under operating procedures which had been modified by a standing order to require manual scram after trip of the recirculation pumps in Operating Modes 1 or 2.

The AIT investigation continued with interviews of control room operating personnel and a walkdown of the control room response to the event. The AIT documented several issues and concerns which were presented to the licensee at a preliminary exit meeting on March 18. The AIT concluded onsite activities with an exit meeting on March 24, 1988.

B. Core Nuclear and Thermal Hydraulic Performance

1. Core Performance

In general, the AIT confirmed the adequacy of the assessment of core performance performed by the licensee and the reactor vendor. Several concerns and questions, however, were developed by the AIT and these are discussed in the Concerns and Recommendations portion of this report (paragraph IV). The following paragraphs provide a discussion of core performance during the event.

Following the trip of the RR pumps, Core Thermal Power (CTP) decreased and stabilized within about 30 seconds at about 40%. The APRMs showed stable indications (the APRMS read neutron flux as distinguished from CTP, however, both were stable at this point). As feedwater temperature decreased, CTP increased slightly to 43%. At approximately 4.8 minutes after the RR trip, the APRMs began oscillating and the LPRM down scale alarms were received. At 5.8 minutes after the RR pump trip, the STARTREC system initiated its second recording for the designed 1 minute period and stopped about 8 seconds before the full scram.

STARTREC information is not available to the operators in the control room at the time of recording, so from the APRM recorders in the control room, the operators believed the oscillations were approximately 25% power (neutron flux) in magnitude (between 25% and 50% power) every 2 to 3 seconds. Analysis of the STARTREC traces showed APRM peak to peak oscillations ranging from 20% to about 95% power. Extrapolation of the traces to the time of the scram leads the AIT to believe the oscillations were at least 100% peak to peak when the scram occurred. The oscillation frequency was approximately 0.45 hz. The approximately 2 second period of the oscillation is driven by core flow hydraulic conditions, primarily the time it takes a void perturbation to travel the length of the fuel . The APRMs measure neutron flux and during reactivity changes the neutron flux leads the fuel cladding heat flux by the thermal time constant of the fuel pellet/pellet-clad-gap arrangement. This time constant is approximately 6-7 seconds and acts to filter neutron flux spikes. Consequently, the heat flux oscillations for this event are estimated to be less than 10% of the neutron flux oscillations cycling around an average CTP of about 45% during the final minute of STARTREC recording. Based on LPRM alarm signals at 87% APRM power and LPRM readings after pump trip, the AIT estimates that the peaking factor increased from 2.11 prior to the event to a value of 2.65 at the time of the APRM alarm. This corresponds to a peak neutron flux level of 312% (relative to rated core average) at the 118% APRM scram level. However, because of the smaller changes in heat flux, the 13.4 Kw/ft fuel design limit was not exceeded and no core damage was indicated by chemistry results.

One of the more important considerations in this type of event is whether the LPRM swings are in phase with the APRMs or not. The reason for this concern is that the core protection actions are actuated by the APRM signals, so, if some LPRMs were oscillating out of phase with the core average, the effect would be to lower the APRM signals that these LPRMs feed. Consequently, the effectiveness of the APRMs as a protective system would be less and local areas of the core would be undergoing oscillations of much greater magnitude than indicated by the APRMs. Analysis of the alarm printout of the LPRM downscale and LPRM hi alarms, the "clean" sinusoidal wave shape, and the in phase APRM traces from STARTREC by the licensee and the reactor vendor (GE) determined that the LPRMs and APRMs were in phase with each other. The AIT verified this analysis and concurred with the licensee's interpretation. This type of oscillation is less severe with lower power peaks to trip than would occur with regional oscillations which have been observed in foreign reactors. Generic analyses performed during the resolution of Generic Issue B-19 bound the LaSalle Unit 2 instability and demonstrated that the fuel thermal or mechanical limits were not exceeded during the event.

General Electric's evaluation of the LaSalle event concluded that the frequency and magnitude of oscillations which Unit 2 experienced were consistent with the characteristics observed during stability testing and operation at other BWRs. GE further concluded that the event was bounded by the generic analysis and that no fuel thermal or mechanical limits were exceeded during the event. While the AIT did not agree or disagree with the GE conclusions at the time of exit, there were several questions and concerns relating to unexpected aspects of the event which required further study. These included the following:

(1) failure to predict the susceptibility of the Unit 2 core to thermal hydraulic oscillations based on the calculated decay ratio.

(2) magnitude of the oscillations compared to previous events with similar behavior,

(3) potential for out of phase regional oscillations of much larger magnitude and the lack of a defined boundary based on inherent shutdown mechanisms,

(4) questions about the adequacy of instrumentation for detection, suppression, and evaluation of limit cycle neutron flux oscillations, and

(5) questions about the adequacy of technical specifications and procedures for detection and suppression of neutron flux oscillations.

These issues are discussed in more detail in paragraph IV, "Concerns and Recommendations".

2. Chemistry Results

Following the scram on March 9, 1988, the LaSalle Station Chemistry Department took post shutdown samples of the reactor coolant water in order to determine if there were any indications of fuel damage. Analysis of the iodine results from this sample indicated no abnormalities (between 2×10^{-3} and 1×10^{-5} microcuries per gram for iodine 131 through 135). The reactor water dose equivalent I-131 was less than 2×10^{-4} microcuries per gram as compared to a Technical Specification limit of 0.2 microcuries per gram. This data, as well as the past two months sample data for both Units 1 and 2, was made available to the AIT for verification by the licensee. As a result of the CAL, the licensee developed an increased frequency sampling program of reactor water and off gas which was implemented following restart of Unit 2. The results of this sampling are documented in Attachment 5 and show no indications of fuel damage or abnormalities from readings prior to the event.

3. Equipment Performance

The following paragraphs summarize the AIT's conclusions regarding the performance of specific systems or pieces of equipment during the event. By the CAL, the licensee was also requested to address equipment performance and that assessment is included in Attachment 5.

(a) Recirculation Pumps and Flow Control Valves

A trip of both RR pumps is a designed feature of the LaSalle plant in order to cause a power reduction in the event of an ATWS, as indicated by a loss of reactor level without an associated scram. The pressure pulse on the reference leg of the ATWS switches appeared to be sufficient to provide this indication and consequently the trip of both pumps occurred as would be expected.

During the RR pump trip recovery, the operators attempted to restart the RR pumps and were unsuccessful. At the time of the exit, the RR pump start failure was believed to be due to the failure to satisfy one of the pump start interlocks. Exactly which interlock was not satisfied was not conclusively determined, however, likely candidates include the recirculation flow control valve not fully in minimum position and the hi speed start permissive (depends on feedwater flow). The operators have no indication available in the control room to determine which RR pump start interlocks are satisfied, however, following the scram, a successful start of the RR pumps was conducted with no abnormalities. The AIT does not believe that the RR pump start failure was indicative of equipment failure but more likely was a failure to satisfy the interlocks compounded by the confusion of the number of things happening at once in the control room. The AIT believes the licensee investigative efforts in this regard were appropriate. Additionally, one of the first problems noted after the transient started was the lock up of the RR pump flow control valves (FCV). Once the operators recognized that the RR pumps had tripped, they responded by trying to ramp the FCV back to minimum position in preparation for RR pump restart. Both FCVs locked up prior to reaching their minimum position. This hindered RR pump restart later. An equipment operator was sent into the plant to reset the FCV lockouts. The Unit 2 NSO was then able to get the A FCV back to minimum position. The B FCV was not reset because there was an abnormal signal alarm which would have required additional operator actions. FCV lockout was not fully investigated by the AIT.

b. Feedwater Heaters

Shortly after the RR pump trip, the feedwater heater level control system began isolating extraction steam from the heaters in order to protect the turbine from water induction. The resultant cooler feedwater which was supplied to the reactor caused the reactor to become even more susceptible to instability. The AIT reviewed the feedwater and feedwater heater performance and concluded that the feedwater heater actions were as expected and had been seen before for similar large rapid drops in load. A more complete description is provided in Attachment 5. This observation, however, negated an initial licensee statement that two abnormal conditions, operation at high power in natural circulation and reduced feedwater heating, were necessary to put the reactor into the unstable region, in that, feedwater heating would be expected to be lost every time both RR pumps were lost from high power. The AIT believed the licensee efforts in investigating the performance of the feedwater system were appropriate.

c. Power to Flow Scram (APRM flow-biased trip)

Since the reactor ends up at lower power following a RR pump trip, and the reactor eventually scrammed on high power in terms of APRM flux, concern was expressed over the operation of the power to flow or APRM flow-biased trip.

The APRM flow-biased trip is designed to protect against spurious scrams due to transient events that cause spikes in neutron flux. APRM neutron flux correlates to thermal power level during steady state conditions. However, during power increase events the APRMs will over-predict thermal power because the neutron flux leads the reactor heat flux due to the thermal time constant of the fuel and cladding. It should be noted that no credit is taken for the flow-biased scram in the transient analysis; only the 120% high flux scram is credited.

The APRM flow-biased trip circuitry receives the APRM neutron flux signal and filters it through an R-C circuit with a 6 second time constant. This R-C circuit which is known as the "thermal power monitor" essentially integrates the APRM neutron flux signal over the past 6 seconds and develops an APRM reading which simulates thermal power by accounting for the lag in response of the fuel cladding heat flux to neutron flux variations. The output of the thermal power monitor is then compared to the flow-biased scram setpoint which is calculated by the equation: $S=0.66\ W_D + 51\%$. W_D is the driving flow which that at 6.9 minutes following the RR pump trip, RPS APRM channels A and B actuated to produce the full scram. APRMs A, C, and E all indicated neutron monitoring trip and are grouped as channel A in the logic scheme. No trip indications appeared for the D and F APRMs which is believed to be due to the fact that the B APRM signal completed the logic and actuated the scram. The licensee's review included a functional check of the APRM trip setpoints following the event, a comparison utilizing gain adjustment factors, and an evaluation of whether the flux oscillations could have been missed by the scram logic. The AIT concurred in the licensee's conclusion that the Reactor Protection System performed as designed. The licensee's investigation of RPS performance was appropriate.

e. Anticipated Transient Without Scram (ATWS)

The only ATWS mitigation equipment actuated by the event was the dual RR pump trip actuated by the pressure pulse to the ATWS RR pump trip switches' reference leg. These functioned as designed to trip off the RR pumps on indicated low reactor level. The operators spent the first 20-30 seconds after the RR pump trip and associated alarm confirming that no condition existed which required a scram without a scram occurring, hence no ATWS. The available recordings also confirmed no other ATWS actuations, which is consistent with the personnel interviews and the initial valving error, in that, no other ATWS actuations would be expected.

C. Operator Performance

On March 17, 1988, as part of the AIT charter, members of the inspection team interviewed the on shift operators and supervisors who had been assigned to Unit 2 during the March 9, 1988, reactor power oscillation event. The licensee's view of operator actions is included in Attachment 5.

Personnel in the control room at the time of the event included the IM personnel performing the surveillance on a headset with the technician at the instrument rack, an NSO at each unit, the Center Desk NSO (who operates Unit 1 and Unit 2 common systems) and the Shift Control Room Engineer (SCRE). The first indication of a problem was a hi level alarm (due to the initial equalization valving error). This brought the Center Desk Operator (CDO) over to the feedwater control station to assist the Unit 2 NSO. As more alarms came in (low reactor level and 1/2 scram due to the second valving error and resultant pressure pulse) the Unit 2 NSO stationed himself at the RR panel. Based on available indication and the fact that an instrument surveillance was in progress, the operators suspected an instrument problem. The Unit 2 NSO determined that he is zero when both reactor recirculation pumps are tripped. Therefore, the scram setpoint (S) during the instability event was 51%.

Although peak APRM readings reached 118%, the peak output of the thermal power monitor during the instability event was approximately 42% to 45% because of the effect of the R-C circuit on the APRM signal. Therefore, the flow-biased scram never reached its setpoint of 51% and the reactor tripped on high neutron flux at 118%.

d. Reactor Protection System (RPS)

From a review of the alarm printer data, the STARTREC information and interviews with operating personnel, the AIT verified that the only RPS actuation setpoints exceeded were those associated with the initial valving errors and related pressure pulsing of the reference leg which started the event and the APRM hi flux scram which ended the event.

The RPS instrumentation which shares the reference leg with 2B21-N037BB consists of Level 3 (+12.5 inches setpoint), Level 2 (-50 inches setpoint), or Level 1 (-129 inches setpoint) differential pressure indicators and straight pressure indicators. The pressure pulse caused by the valving error is believed to have caused the instruments to see about -40 inches reactor level (or a pulse equal to about 80 inches of water column). This pulse would equal about 2.9 psig which would be too small to affect any of the pressure instruments significantly. This corresponds to the alarm printout which indicates no pressure instrument actuations. The 40 inches level would also be expected to be too small to have affected the Level 1 (-129) or Level 2 (-50) instruments, but would have been expected to actuate the Level 3 instruments. No Level 1 actuations were indicated by the alarm printer. However, the ATWS RR pump trip switches 2B21-N036C and 2B21-N036D which did trip the RR pumps are Level 2 switches. This indicates the pulse was either larger than able to be seen by the level transmitter feeding STARTREC or the switch trip setpoints were conservatively high. Consequently, other Level 2 actuations may or may not have occurred depending on setpoint and the strength of the pulse as seen by the instruments. All of the Level 3 switches actuated as would be expected, including the RPS channel B1 low level alarm and 1/2 scram and the Automatic Depressurization System confirmatory alarm. Both of these are confirmed by the alarm printout.

With regard to the APRM hi flux scram, the licensee's On Site Review (OSR) had concluded (from the alarm printout) had lost RR flow and that ATWS alarms were indicated. At that point, efforts were concentrated on ensuring that a valid ATWS event was not occurring.

The Station Control Room Engineer (SCRE) responded to the initial alarms and, remaining cognizant of his position as the SCRE, positioned himself such that he could clearly observe operator actions and reactor parameters. He then contacted the Shift Engineer (SE).

By this point, the NSOs had determined a valid ATWS did not exist and had directed the IM personnel to stop their surveillance. Multiple feedwater heater alarms were occurring and many of the heaters were isolating extraction steam due to the rapid power reduction. A shift foreman had been sent to the local heater control panels to help restore feedwater heating. At about the time of the Shift Engineer's arrival in the control room, preparations were being made to attempt to restart the RR pumps and power oscillations of 25% magnitude ranging from 25% to 50% began to be seen on the APRM recorders. The SE, upon arriving in the control room, quickly assessed the status of the unit, reviewed the operators' actions, and assumed responsibility for efforts to recover from the reactor power oscillations. At this point, operators were uncertain of the specific actions they should be taking once the power oscillations were observed. The procedures and training appear to have been inadequate. The operators all recognized that they were in the region of core instability, but were uncertain of what actions should be taken. The procedures basically instruct the operator to leave the region of instability without directing "how". Thoughts included; (1) driving in control rods in sequence, (2) using the "CRAM" array of control rods, (3) starting a RR pump, and (4) scram the plant. Operators felt that driving in control rods in sequence would have been too slow in that the first rods to go in would be rods of little reactivity worth. Use of the "CRAM" array of control rods was addressed only in the licensee's procedures pertaining to a loss of feedwater heating consequently operators were uncertain if they should use the "CRAM" array in this condition of 2 RR pump trip and loss of feedwater heating. The operators did not want to scram the plant if they did not have to. Therefore, they decided to try and leave the instability region by restarting a RR pump (either a flow increase or a lowering of the rod line would get the reactor out of the unstable region) which they may have accomplished if the RR pump start sequence could have been satisfied. It is also likely that if a RR pump had been successfully started, the reactor may have scrammed anyway on the resultant power increase. As the operators were unsuccessful in starting a RR pump and were preparing for a manual scram, the reactor scrammed automatically.

The AIT evaluated the response of the individuals versus the information they had available, and has the following observations.

- With the exception of the personnel error by the instrument mechanic (IM) that started the transient, the AIT has concluded that the personnel on-shift at the time of the event took prompt corrective action in accordance with the procedures and training available to them. The AIT believes that the operators could have taken better corrective action by driving in control rods, but that this direction was not provided by procedures or training.

- The procedures available to the operators at the time of the event appear to be inadequate in that they don't specifically address the necessary action to be taken in order to exit the region of instability. General Electric Company's Service Information Letter (SIL) No. 380, issued February 1984, addressed the issue of core stability and the actions to be taken if there were a RR pump(s) trip and the core entered the region of instability. The GE SIL had not been incorporated into the licensee's procedures or training. This issue is further discussed in paragraph III.D.

D. <u>Procedure Adequacy and Training</u>

1. Technical Specifications (see Attachment 4)

The LaSalle Unit 2 Technical Specification (TS) 3.4.1.1.b contained the requirements for loss of both RR pumps or "no reactor coolant system recirculation loops in operation". The TS states "immediately initiate measures to place the unit in at least HOT SHUTDOWN within the next 6 hours." The defined actions, however, were not prescriptive for the seven minutes in which the operators had to act for this event. The TS for loss of a single RR pump 3.4.1.1.a, in step 3.4.1.1.a.2a) 2) discusses increasing core flow. While the reactor was not in this condition (both RR loops were not operating versus one), the operators were aware of this TS, the associated surveillance requirements and the fact that increasing flow would get the reactor out of the unstable region of the power to flow map. These considerations in their own minds served to back up the operators decision to restart RR pumps. The NRR representatives on the AIT were familiar with the development of the LaSalle TS and indicated that part of the reason that LaSalle did not have more specific TS was that the Unit 2 decay factor was submitted as 0.60. With this much margin to a Limit Cycle Oscillation decay factor of 1.0, it was believed that the probability of oscillations at LaSalle would be very low. Since oscillations have now been observed and the decay factor calculation is in question (see Concerns paragraph IV), the AIT believes that the TS were inadequate.

2. GE SIL 380 Revision 1 (Attachment 7)

In 1984, GE issued SIL 380 Revision 1 containing recommendations regarding BWR Core Thermal Hydraulic Stability. This document discusses RR pump trip and recommends, "Immediately reduce power by inserting control rods to or below the 80% rod line using the plant's prescribed control rod shutdown insertion sequence." Further, the SIL recommends that the operation of restarting recirculation pumps should be performed from below the 80% rod line. These recommendations were not incorporated into LaSalle's TS or abnormal operating procedures. Like with TS, part of the motivation to not incorporate these recommendations into procedures was based on the margin to instability provided by the calculated decay factor as well as a skeptical attitude regarding the susceptibility of the LaSalle reactors to instability.

3. Abnormal Procedures and Training

The LaSalle abnormal operating procedures (LOAs) and the associated surveillance procedures (LOS) and general procedures (LGP) provided only general guidance regarding what to do in the event of loss of single or two loop recirculation flow. While guidance and training had been provided to all the licensed operators on how to recognize the onset of instability, there was little guidance provided on what to do next, other than performance of the TS required surveillance and to leave the region of likely instability. The loss of recirc flow procedures were directed at restarting RR pumps. The AIT concluded that the operators reacted as their training and procedures led them, in that, they recognized very well the onset of instability, however, interviews indicated they were confused and uncertain as to how to exit the region. The AIT believes that both the abnormal procedures and the training were inadequate in this regard.

4. Simulator Training

The licensee attempted to simulate LaSalle's instability event on the simulator, but was unsuccessful. The event could possibly be simulated with the instructor interacting with the computer, however to produce an accurate, detailed simulation a new program must be written. Currently, the Production Training Software Group has the data from the actual event and is reviewing possible changes. The licensee stated that they expect a permanent program will probably be available by July 1988 and they will keep the resident informed on the status of the changes.

E. Reporting

As the nature and magnitude of the core power oscillations on LaSalle Unit 2 became widely disseminated and understood such that the AIT was formed on March 16, 1988, several questions were raised regarding the adequacy of the licensee's reporting of this event. These questions were in large part motivated by the fact that the majority of the NRC staff did not learn of the core power oscillations aspect of the event until issuance of the Region III morning report update on March 15, 1988, even though the event had occurred on the evening of March 9, 1988. The AIT examined the reporting aspects of this event through interviews, individual recollections and available tape of phone conversations. The following summarizes the team's observations.

1. Reporting Sequence

   (a) Following the trip of the RR pumps and the subsequent scram at about 5:39 p.m. on March 9, 1988, the licensee's initial investigation classified the event as reportable to the NRC within 4 hours under the provisions of 10 CFR 50.72 due to actuation of the Reactor Protection System (RPS). The licensee actually notified the NRC within 1 hour at about 6:32 p.m. on March 9, 1988. The initial phone call communicated information on the RR pump loss due to personnel error, loss of feedwater heating and reactor trip on high APRM flux. No mention was made of the core power oscillations, however, the licensee's caller stated, "we are still investigating all our alarm typers and everything else." Comments were made to the AIT that the licensee's caller sounded almost jovial over the phone. After listening to the tape of the 50.72 call, this observation was explained to the AIT's satisfaction in that the NRC Headquarter's Duty Officer (HDO) and the licensee's caller recognized each other's voices from previous association and exchanged pleasantries. This situation did not appear to detract from proper communication of information.

   (b) The HDO contacted the Regional Duty Officer (RDO) at 7:21 p.m. CST, who, in turn, notified the Cognizant Section Chief (also AIT leader) and Branch Chief.

   (c) At approximately 7:00 p.m. CST on March 9, 1988, the licensee and the Resident Inspector (RI) succeeded in establishing contact and the RI was briefed regarding the event. The RI was offsite attending the Region III Resident Seminar (March 8-10). The licensee informed the RI that the APRMs had oscillated between 25-50% during the event and that the reactor had scrammed on APRM high flux at 118% setpoint. At this point, the RI did not appreciate a significant concern with the APRM oscillation in that oscillations are a potentially expected phenomena given the parameters of high reactor core power and low reactor core flow.

(d) On March 10, 1988, at approximately 10:00 a.m., Region III issued a morning report describing the event. No mention of oscillations was made in this report. The high power scram was attributed to a power surge caused by the cold feedwater.

(e) At approximately 12:30 p.m. on March 10, 1988, the Region III Section Chief contacted the LaSalle Station Manager for the purpose of ensuring the information in a Preliminary Notification (PN) was correct. During this conversation, the Station Manager pointed out that while the PN was substantially correct, the unit had experienced some neutron flux oscillations during the event which were being evaluated. The Region III Section Chief did not include any information on the oscillations in the PN based on the evaluation still being in progress.

(f) On March 11, 1988, the RI returned to the site and participated in several discussions with the licensee involving the event including a meeting where the STARTREC traces showing the oscillations (20%-95%) were made available. The RI was informed that the licensee had involved GE in the evaluation and that GE had indicated the oscillations were within analysis bounds and provided for by the APRM high flux scram. Also, on March 11, 1988, the Station Manager contacted the Region III Section Chief and provided additional information including an explanation of the reactor's position on the power to flow map, the effect of the loss of feedwater heating, and the onset of flux oscillations. During this call, the Section Chief does not recall that the magnitude of the oscillations was discussed, but, rather the Station Manager indicated the oscillations were being evaluated and the reactor vendor was involved. The Station Manager indicated that GE felt the oscillations were within analysis bounds, that the core performed as expected for the conditions and he offered to make a presentation on the event to Region III if desired. The Section Chief indicated this may be a good idea but wanted to wait until the RI and possibly Region III core physics inspectors had a chance to look at the data. Following his review of the available information, the RI contacted the Section Chief on March 11, 1988, and communicated the oscillation information which indicated the event was more severe than initially believed. At this point, the Region III Branch Chief and [illegible] Director were informed that flux [illegible] occurred but were within analysis and a [illegible] description would be available on Monday, [illegible] the RI's further investigation. The [illegible] office was similarly informed.

(g) On March 14, 1988, the RI was given a copy of CECo's Potentially Significant Event (PSE) report and an advance copy of a Rapid SIL generated by GE addressing the event. Due to following up on additional information on the event and the length and complexity of the morning report, the RI was unable to get the report documented and transmitted by the 10:00 a.m. deadline on March 14, 1988. Since Region III was waiting for further information from the site, no additional actions were taken by the Region on March 14, 1988.

(h) On March 15, 1988, the Region III morning report update describing the event, including the oscillations, was disseminated, resulting in the formation of the AIT on March 16, 1988.

2. Reporting Evaluation

In the AIT's view, the licensee correctly classified the event on the initial call on March 9, 1988, as being 4 hour reportable based on the requirements of 10 CFR 50.72 for an RPS actuation. While the initial call did not mention oscillations, the caller stated that the information was still being evaluated. Consequently, the AIT believes the initial call was satisfactory for as far as it went. However, 10 CFR 50.72(c) requires the licensee to make followup notifications in addition to initial notifications as follows:

> (2) Immediately report (i) the results of ensuing evaluations or assessments of plant conditions, (ii) the effectiveness of response or protective measures taken, and (iii) information related to plant behavior that is not understood.

The licensee made no formal followup reports via the ENS circuit (red phone) to the HDO. The AIT believes that such a followup call would have been appropriate since the occurrence of oscillations and the nature and magnitude of the oscillations would significantly add to the information communicated on the initial call. The AIT believes the licensee felt that subsequent calls to the RI and the Region III Section Chief would accomplish the intent of communicating followup information. The AIT believes this to be incorrect for two reasons. First, the intent of 10 CFR 50.72 is to describe the formal notification process which is to be conducted over the ENS circuit and notification of other NRC personnel (including the RI) does not relieve the licensee of the responsibility to notify the NRC via ENS. Second, the information communicated to the NRC in the subsequent calls was insufficient to allow the NRC to appreciate the nature and magnitude of the oscillations. The NRC has a need for prompt, pertinent information on this type event which is at least equivalent to the information which the licensee furnished to GE.

IV. AIT CONCERNS AND RECOMMENDATIONS

A. Concerns

The following paragraphs document concerns developed by the AIT during the review of this event. Several of these concerns were discussed with the licensee prior to the exit and the licensee has provided several responses in Attachment 5 to this report. These responses had not been completely evaluated at the time of the writing of this report. Other issues may require further study and subsequent response.

1. Decay Ratio

Decay ratio in a reactor is a measure of the response of the neutron flux to a change or perturbation. A decay ratio of less than 1.0 indicates that the response to a perturbation will decay to the steady state value (see Attachment 3, Figures 2, 3 and 4). A decay ratio of 1.0 represents the special condition when the response to a perturbation will be a steady state oscillation of constant magnitude (limit cycles). GE predictive methods for determining BWR decay ratio were approved with 20% uncertainty. Predicted decay ratio for LaSalle conditions was 0.60 (40% uncertainty) yet limit cycles were observed. The only obvious deviation from prediction assumptions was in core water level and associated natural circulation flow rate. The 40% difference needs to be explained. Have calculations been discredited as acceptable evidence of core stability?

2. Technical Specifications (TS)

BWR thermal hydraulic stability was the subject of Generic Issue B-19. Early BWRs were designed to maintain decay ratios less than 0.5 (a decay ratio = 1.0 corresponds to an undamped limit cycle oscillation). Later core designs tended towards decay ratios of 1.0 due to higher power density cores and changing fuel design characteristics.

In the resolution of Generic Issue B-19, core designs which were potentially unstable (DR = 1.0) under natural circulation operating conditions were approved with the provision that operating procedures and technical specifications would assure that neutron flux oscillations indicative of core instability would be readily detected and suppressed as required by GDC 12. Licensees were informed by Generic Letter 86-02 that such procedures and TS must be implemented for new reload cores unless it could be demonstrated by approved calculation methods that the core was stable throughout permissible operating regions of the power/flow map. Calculated core decay ratios of less than 0.80 by General Electric methods were approved as acceptable evidence of core stability.

LaSalle Unit 2 did not have fully implemented procedures and TS in accordance with the B-19 resolution because the calculated decay ratio for the current operating cycle is 0.60. LaSalle Unit 2 did have TS and procedures for stability surveillance under conditions of single loop operation (SLO), but had declined suggestions by the NRC staff that these should also apply to two loop operation because higher decay ratios were certain for future reloads. The licensee has been informed that revised TS are required for Unit 2 now that oscillations have actually been observed.

LaSalle Unit 1 is currently under review for reload. The licensee has been informed that stability technical specifications will be required for that reactor even though the calculated decay ratio is 0.75 (indicative that it is less stable than Unit 2).

Since several BWRs have higher decay ratios than LaSalle, the issue of decay ratio in paragraph IV.A and stability TS is considered generic. Improved standard technical specifications relating to stability need to be developed. Further, the implementation status of stability TS on all BWRs should be reviewed with particular attention to the adequacy of requirements for response to loss of RR pumps. The criteria for applicability of stability TS based on decay ratio calculations and reactor type should be reexamined

3. Instrumentation

The following concerns with the available instrumentation at LaSalle were developed by the AIT:

- The slow pen response time and chart speed of the APRM strip chart recorders in the control room reduced indicated amplitude of oscillations.

- Time delay relays for the LPRM Hi and APRM Hi alarms delay recognition.

- Running Average of APRM signal in Power/Flow circuit delays or prevents reactor trip at lower power levels with reactor oscillations.

- If oscillations are regional in nature and LPRM signals are out of phase, LPRM inputs to APRMs will tend to cancel each other so that oscillations are not evident on the APRMs.

- Hi Speed Recording of APRM signals used for event evaluation was triggered by Low Water Level signal - not always a condition of the instability event. This data is needed to assess the nature and magnitude of neutron flux oscillations and the safety of restart after an instability event.

- LaSalle and some other BWRs do not have high speed data recording instrumentation which can be committed for availability during plant operation.

4. Oscillation Characteristics

Some characteristics of the LaSalle neutron flux oscillations were atypical of previous events and have led to concerns about the applicability of previous safety analyses. The magnitude of in-phase limit cycle oscillations previously observed on the APRMs during special stability tests and operating reactor events were typically in the range of 5% to 15% (peak-to-peak) of rated power, and as high as 25%. This compares to peak-to-peak values of about 100% at the time of the 118% neutron flux trip for LaSalle.

The estimated value of local power at the time of trip was greater than 310% and LPRM readings indicate that the core power peak shifted and increased by 25%. Even though the fuel LHGR limit of 13.4 kw/ft was not exceeded because of the thermal time constant of the fuel, the increased power peaking was unexpected based on Vermont Yankee stability tests, and was not factored into the generic safety evaluation performed by GE during review of the thermal hydraulic stability Generic Issue B-19.

The previous GE safety analyses considered several limiting moderate frequency transients which were initiated while the neutron flux was oscillating below the 120% scram setpoint, and included a rod withdrawal error with the flux oscillating up to the 120% scram level. Additional analyses were performed to evaluate the impact of oscillations that approached 300% of rated neutron flux (e.g., regional oscillations) without scram prior to rod insertion and termination of the event. All of these analyses showed that significant fuel thermal margin existed to safety limits. While there are several aspects of these analyses which differ from LaSalle (initial power level and amplitude of the oscillations; no change in bundle peaking factors due to the event, etc.), the AIT agrees that they are sufficiently representative and conservative to demonstrate that no fuel thermal or mechanical limits were exceeded during the event. However, reliable detection and suppression provisions are necessary to assure protection against future events which could involve regional oscillations to higher power levels.

The licensee was also asked to review the impact of the event on stability considerations addressed in the 1979 GE Generic ATWS report, "Assessment of BWR Mitigation of ATWS" (NEDE-24222).

The report does specifically investigate the sensitivity and potential impact of limit cycle neutron flux oscillations up to 500% of rated bundle power following recirculation pump trip. It was concluded that oscillations of this magnitude would not result in sufficient fuel clad temperature variation (130°F) to affect fuel integrity. It was further concluded that a loss of clad integrity due to prolonged exposure to limit cycles was an acceptable consequence in view of the importance of the recirculation pump trip (RPT) to minimize the energy deposited in the suppression pool (thereby maintaining containment pressure within limits) during an ATWS event.

In view of the large magnitude of the APRM oscillations in LaSalle, the AIT believes that the ultimate power level without scram is unknown, and that the 500% level assumed in the ATWS investigation may not be bounding. LPRM oscillation magnitudes more than seven times those of the APRMs have been observed in the case of regional oscillations. The licensee reports that the BWROG is discussing this issue (inherent power limits) and the licensee will provide a status report on July 1, 1988.

5. Additional Concerns

Several additional concerns were presented to the licensee in the form of questions. These questions and the licensee's response are contained in Attachment 5 to this report.

B. Recommendations

The AIT recommends that the concerns identified in items IV.A.1 through IV.A.5 of this report be examined by NRR for generic and LaSalle specific resolution. In the interim, the AIT recommends that revised stability TS as discussed in IV.A.2 be developed for LaSalle Units 1 and 2 and the licensee be authorizied via letter to modify interim operating procedures provided they remain consistent with the new T.S. The revised technical specifications and procedures should incorporate the changes summarized in Attachment 5 (Appendix A, Item 3), which include immediate insertion of high worth rods and observation of APRM/LPRM noise when no pumps are operating and power is above the 80% Rod Control Line. The reactor is to be tripped immediately whenever instability is suspected. It is expected that the time available (greater than 5 minutes) to instability following a two pump trip transient is sufficient to permit manual power reduction, avoiding the need for reactor trip unless the core is unstable by a large margin. Proposed procedures permit manual action for up to two minutes (prior to scram) to reverse operating actions which may result in small margins of instability when one or both pumps are operating.

V. AIT CONCLUSIONS

The AIT finds that the core power oscillations observed on LaSalle Unit 2 on March 9, 1988, were initiated by a personnel error resulting in the trip of both recirculation pumps compounded by the loss of steam heating to the feedwater. The licensee's evaluation of the event (including assistance from the reactor vendor) is still continuing, however, to date is believed to have been thorough and proper. No evidence of any fuel damage has been noted related to the event. Performance of equipment during the event is believed to have been as designed for the conditions encountered during the event. Operator performance, while it could have been better, is believed to have been prompt, appropriately controlled and within the bounds of the procedures and training available to them. Both the procedures and training available to the operators are believed to have been inadequate in that prudent recommendations of GE SIL 380 were not incorporated and little direction was provided regarding what to do in the event of instability. Reporting is believed to have been inadequate in that no formal followup report was made regarding the results of the investigation and determination of flux oscillations. The licensee's response to NRC initiatives by shutting down, providing the AIT with prompt and technically sound information and responding to the CAL is believed to have been excellent. Several concerns and recommendations on this event remain to be followed as documented in paragraph IV.

On March 17, 1988, the AIT determined that the licensee had complied with the restart provisions of the CAL, including a requirement for a manual scram in the event of a loss of both recirculation pumps from an operating condition, and the Region III Administrator's designee authorized restart of LaSalle Unit 2 at 10:45 p.m. The AIT and the licensee have agreed on the essential features of revised technical specifications and operating procedures to protect against this event during future operation.

VI. EXIT INTERVIEW

The inspectors met with licensee representatives (denoted in paragraph I.D.) informally throughout the inspection period and at the conclusion of the onsite inspection activities on March 24, 1988, and summarized the scope and findings of the inspection activities.

The inspectors also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspectors during the inspection. While the inspectors did review some proprietary material, none of the areas expected to be contained in the report were identified by the licensee as proprietary. The licensee acknowledged the findings of the inspection.

CAL-RIII-88-03

Docket No. 50-374

Commonwealth Edison Company
ATTN: Mr. Cordell Reed
Senior Vice President
Post Office Box 767
Chicago, IL 60690

Gentlemen:

This letter confirms the telephone conversation between E. G. Greenman of this office and you on March 17, 1988, related to the dual recirculation pump trip and related core performance anomalies occurring at LaSalle Unit 2 on March 9, 1988. With regard to this event, we understand that you will:

1. Perform an evaluation of reactor performance during this event including secondary systems, the reactor protection system, and ATWS systems.

2. Perform an evaluation of operator performance during this event.

3. Evaluate the adequacy of your Technical Specifications, operating procedures, abnormal operating procedures, and emergency procedures with respect to this event and vendor recommendations (GE SIL-380).

4. Perform increased activity level sampling during Unit 2 startup to verify no abnormalities.

5. Submit to NRC Region III a formal report of your findings and conclusions within 30 days of receipt of this letter.

Throughout this investigative effort, we understand that you will take those actions necessary to ensure that complete documentary evidence of the conditions being examined is maintained, and furnished to the NRC's Augmented Inspection Team which was initiated on March 16, 1988.

8803220319 8pp.

Attachment 1

We further understand that startup of Unit 2 will occur after a determination has been made by the AIT Team Leader that equipment performance was satisfactory, including verification of reactor coolant samples, and that interim procedural changes are satisfactory including a requirement to trip the reactor if no reactor recirculation loops are in operation, and the reactor is in operational conditions 1 or 2, and with concurrence of the Regional Administrator or his designee. Issuance of this Confirmatory Action Letter does not preclude the issuance of an order requiring implementation of the above commitments.

None of the actions specified herein should be construed to take precedence over actions which you feel necessary to ensure plant and personnel safety.

Please advise us immediately if your understanding differs from that set forth above.

Sincerely,

Orignial Signed by A. Bert Davis

A. Bert Davis
Regional Administrator

cc: D. Butterfield, Nuclear Licensing Manager
G. J. Diederich, Plant Manager
DCD/DCB (RIDS)
Licensing Fee Management Branch
Resident Inspector, RIII
Richard Hubbard
J. W. McCaffrey, Chief, Public Utilities Division
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J. M. Taylor, DEDO
T. E. Murley, NRR
E. L. Jordan, AEOD
J. Lieberman, OE
M. Johnson, EDO
W. Lanning, NRR
F. Miraglia, NRR
G. Holahan, NRR
D. Crutchfield, NRR
J. Partlow, NRR
J. Strasma, RIII
J. Goldberg, OGC
D. Muller, NRR

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
799 ROOSEVELT ROAD
GLEN ELLYN, ILLINOIS 60137

March 17, 1988

MEMORANDUM FOR: Mark A. Ring, Team Leader, LaSalle Augmented Inspection Team (AIT)

FROM: Edward G. Greenman, Director, Division of Reactor Projects

SUBJECT: AIT CHARTER (DRAFT)

Enclosed for your implementation is the draft Charter for the inspection of the events associated with the LaSalle reactor trip which occurred on March 9, 1988. This Charter is prepared in accordance with the NRC Incident Investigation Manual, Revision 1. The objectives of the AIT are to communicate the facts surrounding this event to regional and headquarters management, to identify and communicate any generic safety concerns related to this event to regional and headquarters management, and to document the findings and conclusions of the onsite inspection.

If you have any questions regarding these objectives or the enclosed Charter, please do not hesitate to contact either myself or W. Forney of my staff who is the regional point of contact for the LaSalle AIT.

Edward G. Greenman

Edward G. Greenman, Director
Division of Reactor Projects

Enclosure: AIT Charter

cc w/enclosure:
A. B. Davis, RIII
C. J. Paperiello, RIII
M. J. Virgilio, RIII
F. Miraglia, NRR
D. Crutchfield, NRR
E. Jordan, AEOD
J. Partlow, NRR
C. Rossi, NRR
G. Holahan, NRR
W. Lanning, NRR
D. Muller, NRR
M. Johnson, EDO
LaSalle, RI

Attachment 2

8805250197 3pp.

Draft Augmented Inspection Team (AIT) Charter

LaSalle Core Oscillations Event of 3/9/88

You and your team are to perform an inspection to accomplish the following:

1. Develop and validate the sequence of events associated with the March 9 scram of LaSalle Unit 2. Include plant conditions immediately prior to the initiating events and any contributory causal factors leading to initiation of the event.

2. Review the core nuclear and thermal/hydraulic performance during the event.

   a. Examine the licensee's/vendor evaluations. Determine whether the event was previously analyzed or fits within existing analyses. Include the recirculation pump trip and feedwater system response. Review analysis for the potential for core damage.

   b. Review/evaluate related plant responses including secondary systems and the reactor protection and ATWS systems.

   c. Confirm the absence of any resultant plant damage.

3. Interview on-shift operators and supervisors to:

   a. Determine if they had been appraised of the potential for this type of transient or had been provided with training relevant to it.

   b. Determine initial activities.

   c. Determine indications available and used.

   d. Establish shift responses including supervisors.

   e. Characterize the decision processes involved in restart of the recirculation pumps.

   f. Characterize operators use of plant procedures.

   g. Establish why prompt action was not taken to terminate the transient through either normal rod motion or manual scram.

4. Review procedures for adequacy.

   a. Include normal, abnormal , and emergency procedures.

   b. Determine if Technical Specifications contain relevant restrictions on power/flow/trip setpoints and rod configurations.

   c. Evaluate the relationship of the TS and procedures to the GE analysis SIL-380.

   d. Consider changes that may be desirable.

5. Interview management to determine:

   a. When it was first informed of the event.

   b. The nature of the information communicated.

   c. The directions/decisions provided to the operating shift.

6. Reporting.

   a. Evaluate the accuracy, timeliness, and effectiveness with which information on this event was reported to the NRC, including the Resident Staff.

7. Evaluate the findings and identify those for which generic communications may be applicable.

Commonwealth Edison
One First National Plaza, Chicago, Illinois
Address Reply to: Post Office Box 767
Chicago, Illinois 60690 - 0767

April 15, 1988

Mr. A. Bert Davis
Regional Administrator
U.S. Nuclear Regulatory Commission
Region III
799 Roosevelt Road
Glen Ellyn, IL 60137

Subject: LaSalle County Station Unit 2
Response to Confirmatory Action Letter
NRC Docket No. 50-374

Reference: A. B. Davis letter to Cordell Reed dated
March 17, 1988 transmitting CAL-RIII-88-03.

Dear Mr. Davis:

The above referenced Confirmatory Action Letter (CAL) requested that Commonwealth Edison submit a formal report of our findings and conclusions relating to the LaSalle County Unit 2 event of March 9, 1988 in which there was a dual recirculation pump trip and subsequent core performance anomalies. This report responds to the issues listed in the CAL and the subsequent questions submitted by the Augmented Inspection Team (AIT). We would like to express our appreciation for the AIT Team's willingness to work extended hours to expedite their thorough investigation in order to accommodate plant conditions.

This letter and the attachments respond to all issues and questions regarding this event. Attachment A responds to the four items stated in the CAL. Attachment B responds to the list of questions presented at the preliminary exit meeting on March 18, 1988. Attachment C responds to the seven additional questions presented on March 23, 1988. Attachment D responds to the three additional questions presented to us prior to the AIT exit meeting on March 24, 1988.

Please address any questions that you or your staff may have concerning this response to this office.

Very truly yours,

M. S. Turbak

M. S. Turbak
Assistant Licensing Manager

lm

Attachments: As Stated

Attachment 5

cc: P. She

4495K

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ATTACHMENT A

COMMONWEALTH EDISON COMPANY RESPONSE TO

THE MARCH 17, 1988, CONFIRMATORY ACTION LETTER (CAL)

1. Perform an evaluation of reactor performance during this event including secondary systems, the reactor protection system, and ATWS systems.

A detailed review of the systems performance was conducted prior to On-Site Review for Unit 2 Startup. All alarms/actuations received indicated as expected for the valving sequence described by the instrument technicians involved.

A summary of the Anticipated Transient Without Scram (ATWS), Reactor Protection System (RPS), and secondary systems performance is included below:

ATWS

The rapid closure of the reference leg isolation valve on Wide Range instrument 2B21-N037BB caused a pressure pulse on the reference leg of all Narrow and Wide range instruments which share the reference leg at that rack. Increasing pressure on the reference leg side will cause the level instrument(s) to indicate low vessel level.

Because the Wide and Narrow range transmitters at the same instrument rack (2H22-P027) feed the Startrec computer, the approximate magnitude of the pulse can be observed in the computer output. When corrected for Startrec calibration error, this signal appears to have a minimum level of approximately -36 to -40 inches. Therefore, only Level 3 (+12.5 inches) actuations would be expected, and possibly some Level 2 (-50 inches) instruments could trip if their setpoints were conservative and/or the pressure pulse was slightly more severe than the pulse at the Wide Range transmitter feeding Startrec.

ATWS Reactor Recirculation (RR) pump trip switches 2B21-N036C and 2B21-N036D are installed at instrument rack 2H22-P027, and share the reference leg with the 2B21-N037BB switch being tested by the Instrument Mechanic (IM) technician. Switch 2B21-N036C is designed to trip the "A" RR pump to OFF by tripping the "3" (high Speed) and "2" (low Speed) breakers (reference electrical schematic 1E-2-4205AB). Switch 2B21-N036D is designed to trip the "B" RR pump to OFF in the same manner (schematic 1E-2-4205AM). Therefore, a spike on the common reference leg of these two instruments could be expected to cause both pumps to trip-off if it were sufficient to trip one. The results are in reasonable agreement with the observed spike.

The other Level 2 functions at the P027 rack would not necessarily be expected since the size of the pulse was marginal for a Level 2 actuation. The Reactor Core Isolation Cooling (RCIC) switch under test would not actuate with its equalizing valve open, so even if the other switch at that rack actuated (2B21-N037DB), a RCIC actuation would not result because both switches are required. No Alternate Rod Insertion (ARI) initiation occurred because only one level transmitter is connected at the rack, and the logic requires more than one level signal. Had the ARI level transmitter at the P027 rack spiked sufficiently to actuate the ARI Level 2 signal, a printout on the process computer from digital point C567 would be expected if the low level signal existed for greater than 1 full second (the duration of the spike was less than 1 second). This point did not print.

The rest of the instruments at the rack are Level 1 or Level 3 functions, or straight pressure instruments which would not be affected by the pulse of less than 60 to 70 inches of water column (inwc) (2.5 psi).

No Level 1 (-129 inches) actuations were experienced or expected, since the magnitude of the spike was not large enough.

RPS

The Level 3 (+12.5 inches) switches at 2H22-P027 actuated as designed. One of these (2B21-N024B) provides the RPS channel B1 low level 1/2 scram. The pressure spike on the instrument reference leg drove the narrow range instruments to read low, indicating a minimum of about 0.0 inches. The RPS B1 Level 3 alarm was received, and the associated 1/2 scram was also received (NOTE: the Hathaway printout shows the 1/2 scram alarm, then 6 milliseconds later the Level 3 alarm. This is due to the relay configuration for the Level 3 alarm having an extra slave relay to provide the alarm. The relay delay causes the indicated time discrepancy). The Level 3 alarm condition cleared approximately 1.2 seconds after it occurred. The 1/2 scram was reset 5.0 seconds after the Level 3 alarm cleared, after stable level indication was observed. These actuations are as expected. No prolonged low level signal existed, and no other RPS channels were affected. Therefore, a full scram was not to be expected.

The other Level 3 indication at the P027 rack was from the Level 3 Automatic Depressurization System (ADS) confirmatory switch 2B21-N038B. This alarm was also received and cleared in the same time frame as the Level 3 RPS alarm, indicating consistent performance of the level switches.

Average Power Range Monitor (APRM) FLUX TRIP

The performance of the RPS in response to APRM trip signals was evaluated in the On-Site Review (LOSR 88-16). That review showed that the only APRM signals exceeding the trip setpoint caused the appropriate 1/2 scram, and then full scram, RPS actuations. The scram went to completion properly, with all rods scramming in to the full in position. No anomalous behavior of the RPS or RPS inputs was noted during the event review.

SECONDARY SYSTEMS PERFORMANCE

RR Pump Logic

The exact cause for the initial inability to start the "A" RR pump during the event on March 9, 1988, could not be determined conclusively. It is believed that a pump start permissive was not satisfied.

Approximately one minute prior to the scram, alarms indicating loss of high speed (RR) pump permissives occurred. These alarms, if not cleared, would prevent high speed operation of the RR pumps. The Hathaway typer shows that these alarms did not clear before the scram. The Startrec data shows that the low FW flow condition existed when the RR MG set was started. Feedwater flow increased to above the high speed permissive approximately seven seconds after the MG set start. It is believed that shortly after this, the operator attempted to start the RR pump. In this condition, no pump start would be possible because the start logic would be routed to the High Speed relay, which was sealed out from the previous low FW flow condition.

Static "O" Ring (SOR) Performance

The SOR switches performed properly during the event on March 9, 1988. There were six (6) other SOR switches which utilized the same reference leg as DPS-2B21-N037BB. Two (2) of the switches have level 3 setpoints;

-2B21-N024B Reactor Vessel Low Water Level Scram, and
-2B21-N038B Reactor Vessel Low Water Level 3 Confirmed for ADS.
Three (3) of the switches have level 2 setpoints;
-2B21-N037BB and, 2B21-N037DB Division 2 RCIC Initiation, and
-2B21-N026BB Division 1 Primary Containment Isolation System (PCIS) Inboard Isolation function.
Two (2) of the switches have level 1 setpoints;
-2B21-N037BA Division 2 Permissive for ADS/Residual Heat Removal(RHR), and
-2B21-N037DA Division 2 Permissive for ADS/RHR.

Upon isolation of the reference leg from the variable leg, a low "indicated" level spike was received by the instruments which utilized the same reference leg as DPS-2B21-N037BB. The spike caused the level 3 switches (2B21-N024B and 2B21-N038B) to trip. 2B21-N026BB which gives 1/2 of a Level 2 PCIS Groups 2 through 5 isolation signal did not actuate as evidenced by the lack of an alarm on point R0873. The other SOR switches, which had lower setpoints, did not trip. These are discussed earlier under item #1 (ATWS performance).

During the time period between the trip of the RR pumps to the scram, vessel level did not approach level 3 (level remained above 30 inches). This was confirmed through discussions with the operating personnel involved in the event, and a review of upset, wide range, and narrow range level indications from control room recorders and Startrec.

Within 7 to 9 seconds following the scram, all 4 SOR low level (level 3) scram switches tripped, and the low level (level 3) confirmed alarm was received, demonstrating consistency in the response of the level 3 SOR switches. Startrec was not recording at the time of the scram, so the level at which the switches tripped is not known. There were no level 2 SOR initiations following the scram.

All SOR switches which utilized the same reference leg as DPS-2B21-N037BB were functionally tested prior to startup.

Feedwater and Feedwater Heaters

During normal steady state operation, feedwater heaters have level controlled via the normal drain valves to the next lower heater in a cascade (typical). Inputs to the feedwater heaters are turbine extraction steam and drain from the next higher heater in a cascade. During transient conditions where large drops in turbine load (steam flow) occur the extraction steam pressures change as well as the extraction steam flows. This affects the feedwater heater level in several ways including: steam flashing due to lower heater shell pressures, reduction in inputs due to reduced extraction steam flows, changes in the condensing rate due to reduced feedwater/condensate flow, etc. The heater level control system tries to react to this transient with the normal and emergency level control valves but it is designed for normal operation and does not react fast enough for this type of transient. The heaters trip (loss of the extraction input) due to high level to protect the turbine from water induction. The performance of the feedwater heaters after the March 9th Unit 2 scram was reviewed and found to have performed as would be expected from the large drop in turbine load.

During review of the feedwater system performance, it was noted that vessel level was cycling with a slightly larger band than normal. Vessel level was seen to swing inside a level band of approximately 15 inches, cycling on about a 30 second period.

During checkouts of the feedwater controls, a sticking actuator positioner on the 2A Turbine Driven Feed Pump steam control valve was found. This positioner was found to be causing a delay of approximately 5 to 6 seconds in the control valve response. The positioner was replaced during the unit outage, and verified to allow proper control valve response.

Subsequently, review of the control system data recorded during the March 9 transient indicated that the feedwater pump turbine control valve response delay was responsible for the swings in feedwater flow, which caused the vessel level swings. The positioner replacement is considered to be sufficient to resolve the questions about the level oscillations

2E12-F009 Valve Failure to open when going into Shutdown (S/D) cooling on U-2.

The unit was cooled down to 299°F for 2 hours before trying to open the valve for the first time. The valve tripped on thermals the first try. The thermals were reset and allowed to cool for ~ 30 minutes, then the valve was tried again (this was ~0530 hours). It again tripped on thermals. At this time personnel were ready to go into the drywell. The decision was made to have the U-2 Foreman also go in with them to assist the valve off its seat manually. This decision was made in an effort to expedite getting S/D cooling on, in order to get into cold S/D so planned work could start. The valve was manually cracked off its seat by personnel making the initial drywell entry, (~0645 hours) and opened easily the rest of the way with the motor.

Pressurizing between the 006B and 009 valve with the Cycle Condensate System (CY) per LOP-RH-07 was not done because the time it would take would delay the start of critical path outage work.

The conclusion of the On-Site Review was to complete installation of Modification M-1-2-88-007 during the second refueling of Unit 2. This Modification will install a larger Motor operator on 2E12-F009 similar to the modified Unit 1 valve.

2. Perform an evaluation of operator performance during this event

Initial conditions on Unit 2 were 84% power (930 MWe) and steady state. LIS-NB-404 was in progress which tests the Reactor Core Isolation Cooling (RCIC) initiation at -50". This surveillance requires a Technician on headsets in the Control Room communicating with the Technician at the instrument rack. The Instrument Maintenance Department (IMD) Technicians received permission from the Shift Engineer (SE), then the Shift Control Room Engineer (SCRE), and lastly the Unit 2 Nuclear Station Operator (NSO) which is standard procedure. There were 2 NSO's at the Unit 2 Station, the Unit 2 NSO and the Center Desk NSO (Center Desk operates the common systems between Unit 1 and Unit 2). The SCRE was in his normal station of observation between the Units and the SE was in his office just south of the Control Room.

The initial sign of a problem was an alarm on the Reactor Control Panel (2H13-P603) which was a hi level alarm. The Center Desk NSO immediately assumed the Feedwater Control (FWC) station located at 2H13-P603. While reviewing FWC additional Reactor Water Level (RWL) related alarms indicating both hi and lo Reactor Water Level (RWL) were received on Control Room panels. A half-scram at +12.5" RWL also occurred. FWC appeared normal, in that it was responding to a level signal and there were no erratically functioning controllers; however, upon review of the 3 Narrow Range (NR) RWL indicators, the NSO saw 'B' NR at approximately 30" and rising while the 'A' and 'C' NR indicators were steady at approximately 40". The 'B' NR was providing the level signal to FWC. The NSO deduced an instrument problem and reset the hi RWL trip and the half-scram. He suggested that a Reactor Recirculation (RR) Pump runback may be in progress as indicated by rapidly decreasing Power, Feedwater Flow and Steam flow. The above occurred over a time span of about 23 seconds. This 1/2 isolation signal has not been possible to confirm. The 1/2 isolation should be accompanied by an alarm.

The Unit 2 NSO was reviewing the RR panel. He found RR flow at zero, no pump amperes, the slow speed motor-generator sets were not running and the Flow Control Valves (FCV) were open - not at minimum position as the case would be on a runback. There were Anticipated Transient Without Scram (ATWS) alarms on the panel which indicated to the operator the RR pumps had tripped in response to an ATWS signal. There also appeared to be a 1/2 Primary Containment Isolation System (PCIS) RWL trip present for the Main Steam Isolation Valves (MSIV's). This 1/2 isolation signal has not been possible to confirm. The 1/2 isolation should be accompanied by an alarm from point R0109 which would actuate if the local level transmitter (2B21-N402B) had spiked sufficiently. It is believed that the alarm at 2H13-P601 "DIV 2 RX LVL LO/PRESS HIGH" was interpreted as being the alarm associated with the low low level MSIV isolation. The alarm which did annunciate (recorder point R1235/window E303 at H13-P601) is driven from the Wide Range Level recorder 2B21-R884B, which is fed from level transmitter 2B21-N026BA at the same instrument rack (P027) where the valving error occurred. This window alarms at +12.5 inches, decreasing, and could easily be confused with the alarm at E504, which would actuate in conjunction with a 1/2 MSIV isolation on low reactor Level 1.

The Unit 2 NSO was cognizant of the actions taken by the Center Desk NSO. He also knew there was a surveillance in progress on a -50" RWL switch, consequently he suspected some sort of instrument problem and directed the Instrument Technician to stop what was in progress. The Technician acknowledged the direction and indicated he didn't think there was a problem with the surveillance. The U-2 NSO also reset the 1/2 PCIS signal.

The SCRE responded to the event when the initial RWL alarm occurred. He positioned himself at Unit 2 such that he could clearly observe operator actions and reactor parameters. He saw there was a problem with RWL indication and that the RR pumps had tripped off. He verified power had decreased and called the Shift Engineer to the Control Room. He reviewed the actions the NSO's had taken and found them proper.

The Unit 2 NSO also reviewed the feedwater heater situation since the rapid power reduction had caused many heaters to trip. He planned to re-open the extraction steam valves to regain some feedwater heating after the valves fully closed. He was also aware that a Shift Foreman was dispatched to the local heater controllers to aid in reestablishing feedwater heating. He placed FW temperature in a computer window to trend.

During the next few minutes preparation began for restart of the RR pumps as called for by LOA-RR-07. The Flow Control Valves (FCV's) on both pumps locked up as they were ramped to minimum position. An Equipment Operator (EO) was dispatched to reset the lockouts. This time frame is about 4 to 4-1/2 minutes into the transient (after the initial level alarm).

At approximately this point the IM Technician in the Control Room indicated the problem may have resulted from a valving error at the instrument rack.

The SE arrived in the Control Room approximately 3 to 3-1/2 minutes into the transient. His analysis identified that both RR pumps were off; Average Power Range Monitors (APRMS) were oscillating from 20-50% of scale; reactor pressure and level were normal; FWC appeared normal; Feedwater Heaters were tripping in response to the large downpower and FW temperature was decreasing but normal on a downpower trend. His initial comment was that a manual scram may be necessary, if we cannot stabilize the transient quickly.

At almost the same time the NSO at FWC asked him if the reactor should be scrammed. The SE told him to prepare for a manual scram at his (SE's) direction to which the NSO acknowledged.

The SE directed the U-2 NSO back to the RR station (he had returned to the feedwater heating station).

The SE directed the Shift Foreman at the heater controllers to place the heaters on emergency spills and that the Control Room would get back to him later.

The Unit 2 NSO was able to get the A FCV back to minimum position now since the EO had reset the lockout. The B FCV lockout wasn't reset as there was an abnormal signal alarm which would require additional operator actions. This occurred about 6 minutes into the transient.

The SCRE conferred with SE and recommended an attempt to restart RR before manually scramming the reactor. The SE's thought process ruled out a major problem due to loss of FW heating since the large power decrease (approximately 40%) had caused most of the 50-60°F reduction. He recognized the plant was in the instability region and that actions to leave the region were required. Thought was given to normal, in sequence Control Rod (CR) insertion, but there wasn't time for this. Also, the SE was not sure whether or not use of "Cram" arrays would lead to further local power problems, so he decided that any CR movement would be via SCRAM. A restart of RR per LOA-RR-07 could restore core stability. LOS-RR-SR1, Thermal Hydraulic Stability Surveillance, did not address an abnormal situation such as this. Since no abnormal procedure applied to the situation any more than LOA-RR-07 he agreed and directed the Unit 2 NSO to attempt a restart of RR. Two attempts to start 2A RR pump did not succeed. As the SE was about to direct a manual scram be carried out, the reactor tripped on high neutron flux. The reactor scram occurred about 7 minutes into the transient. The operators carried out the scram procedure without further incident.

The operators adhered to the station procedures and their actions addressed returning the reactor to a stable condition. Station review identified that adequate procedural guidance to this situation was not provided to the operators. Measures were taken to correct that deficiency. Command in the Control Room was clearly demonstrated by the SE. He took positive actions to return the plant to a stable condition. The SCRE assessed the event as it progressed and provided information to the SE. The NSO's demonstrated their abilities to correctly interpret control board indications and take the immediate actions. The Station's Assessment of the Operator Actions is that they were knowledgeable of the transient and plant indications and that their actions were prompt, responsive and proper.

3. Evaluate the adequacy of your Technical Specifications, operating procedures, abnormal operating procedures, and emergency procedures with respect to this event and vendor recommendations (GE SIL-380)

Following the scram of LaSalle Unit 2 on March 9, 1988, a review of operating procedures for normal and abnormal situations involving Reactor Recirculation (RR) pumps and/or core flow changes was conducted. Procedure changes were implemented which were intended to improve the timeliness of operator response to RR pump trips and/or neutron flux instabilities. The following list of procedures outlines the changes which were initiated. All procedure revisions are complete.

1. ABNORMAL PROCEDURES (LOA)

LOA-RR-06 SINGLE RR PUMP TRIP

Immediate Action: Insert CRAM rods to 00 if Flow Control Line (FCL) was >80% prior to pump trip, frequently MONITOR APRM and LPRM flux indications and either increase flow on the operating RR loop or decrease power with rods to exit region. References operator to LOA-RR-09 if instability is suspected.

Subsequent Action: Perform Stability surveillance LOS-RR-SR1, i.e., in SLO, may be in surveillance region.

LOA-RR-07 TWO RR PUMP TRIP

Immediate Action: Insert CRAM rods to 00 if FCL >80% prior to pump trip, and continue to insert rods to below 80% FCL, MONITORING APRM/LPRM noise. References LOA-RR-09 if instability is suspected.

Subsequent Action: Perform Stability surveillance LOS-RR-SR1

Added explanation of instabilities in Discussion section, including wording that states "Unstable neutron flux oscillations have occurred . . ." to emphasize that the phenomenon has actually been experienced. Explained that the basis of not restarting tripped pump(s) until below 80% FCL is to avoid diversion of operators attention from stability concerns.

LOA-RR-09 CORE INSTABILITIES (NEW PROCEDURE)

The operator is directed to this procedure by the RR pump trip LOA's, LPRM HI, APRM HI, LPRM DOWNSCALE, Thermal Hydraulic Stability Surveillance, Restart of Tripped pump(s), Changing RR pump speed from HI to LOW speed, and Pump Shutdown procedures whenever instability is suspected.

Immediate Actions: If FCL >80% and Core Flow <45%, insert CRAM rods to 00, then insert rods in sequence to get below 80% FCL. MONITOR APRM/LPRMs. If instabilities have not been terminated within 2 minutes SCRAM reactor.

Subsequent Actions: Perform LOS-RR-SR1, reduce FCL to below 80%, and continue monitoring APRM/LPRMs.

LOA 1(2)H13-P603:

WINDOW A407 LPRM DOWNSCALE

Note that a regular cycling of this alarm, especially at a 2-3 second period could be indicator of instability. Instructs operator to select the "yellow" stability monitoring rods. Refers to LOA-RR-09 if instability is suspected. Notes that Full-core display maybe observed for multiple alarms.

WINDOW A108 APRM HI

Instructs operator to observe APRM recorders and LPRM meters for flux oscillations >10% peak-to-peak. Refers to LOA-RR-09 if instability is suspected.

WINDOW A307 LPRM HI

Notes that periodic alarm may indicate instability. Instructs operator to select "yellow" stability monitoring rods. Refers to LOA-RR-09 if instability is suspected. Discussion describe conditions of possible instability, and indications, especially 2-3 second period.

2. SURVEILLANCES

LOS-RR-SR1 THERMAL HYDRAULIC STABILITY SURVEILLANCE

Revisions were made to let the operator obtain the raw noise data without delay, then compare to baseline data. A fixed criteria of 10% was introduced which would enable the operator to take corrective action prior to comparing all the results to 3 times the baseline.

Certain Control Rods highlighted with a yellow background to enable quick selection for LPRM monitoring.

The surveillance sheet was also re-formatted to eliminate look-ups by the operator, for determination of rod selections/core regions.

LOA-RR-09 is referenced for instability indications.

3. OPERATING PROCEDURES

LOP-RR-06 RESTART OF TRIPPED RR PUMP

Add reference to LOA-RR-09. Add prerequisite FCL less than or equal 80%. Add NOTE to watch out for instabilities with less than 45% Core Flow before/during decreasing flow on active loop to meet pump start requirements.

LOP-RR-08 CHANGING RR PUMPS FROM FAST TO SLOW

Add reference to LOA-RR-09. Add precaution that downshift, if above 80% FCL could result in operation inside stability surveillance region, and possible instabilities could result, complete FCL reduction to below 80% FCL if possible, prior to downshift. The first step after verifying proper RR equipment operation on downshift is to VERIFY core stability per LOS-RR-SR1.

LOP-RR-09 REACTOR RECIRCULATION PUMP SHUTDOWN

Add reference to LOA-RR-09. Add precaution that the flow decrease from RR pump shutdown may result in entry into stability surveillance region. Complete FCL reduction to <80% FCL prior to pump shutdown, if possible.

Instructs operator to VERIFY core stability after pump shutdown, referring to LOA-RR-09 if instability is suspected.

LTS-1200-4 NUCLEAR ENGINEERS DAILY SURVEILLANCE

Added procedure steps to ensure that the CRAM array check on the checklist includes verification that all CRAM rods are properly indicated with RED tape on select buttons.

LAP-100-13 CONTROL ROD SEQUENCE PREPARATION

--PROCEDURE DEFICIENCY WRITTEN, NO REVISIONS PERFORMED--

Procedure changes incorporated the requirement for the Nuclear Engineer to place and verify RED tape on the associated CRAM rod select buttons. Operator instructions to continuously insert all "taped" rods to position 00 and then sign off the appropriate INSERT steps, was incorporated. Attachment G (CRAM Array instructions) was revised to require the Nuclear Engineer to record the specific rods associated with the designated CRAM arrays.

In addition to the procedure review discussed above the Unit 1 and Unit 2 Technical Specifications were reviewed. As a result of discussions held with the AIT team members revisions to the LaSalle Unit 1 and Unit 2 Technical Specifications have been prepared and submitted to Offsite Review.

The revised procedures are fully consistent with General Electric Service Information Letter (SIL) 380 Revision 1. Changes to procedures needed to be consistent with the proposed Technical Specifications will be incorporated upon approval of the Technical Specification.

The Confirmary Action Letter (CAL) RIII-88-03 directed the Station to initiate a Manual Scram in the event that no reactor recirculation pumps are in operation in Conditions 1 or 2. This requirement has been provided to Station Operators via Special Operating Order 88-21. This Special Operating Order was reviewed by the AIT team leader prior to startup of Unit 2 following receipt of the CAL.

4. <u>Perform increased activity level sampling during Unit 2 startup to verify no abnormalities</u>

Daily readings of the Offgas pretreatment and offgas post treatment Radiation Monitors taken since March 19, 1988 show no evidence of changes in the fission gas release rates when compared to data at comparable power levels prior to March 9, 1988.

The twice weekly reactor water iodine and offgas analyses show the same recoil versus non-recoil pattern and full power adjusted release rates from the fuel when compared to data taken prior to 3/9/88.

The offgas pretreatment monitor and offgas post treatment monitors are operating at levels well below their alarm setpoints. The dose equivalent I-131 level is well below the (Technical Specification 3.4.5) 0.2 microcurie per gram limit.

The data collected as part of the evaluation plan is presented in Table 1. The monitor setpoints are listed as footnotes to the table.

Data collection and increased sampling of reactor water and offgas continues as stated in the evaluation plan. Unit 2 was operated at greater than 90% power from April 1, 1988, to April 5, 1988; the reactor water iodine and offgas analysis will continue at the twice a week frequency until April 22, 1988 at which time the normal frequency of once per week will be reestablished.

TABLE 1

Date	Power (MW_T)	Pretreat (mR/hr)	Post Treat (CPS) A	B	Noble Gases $\sum 7\mu ci/sec$	DE I-131 $\mu ci/g$
3/19	1452	48	750	900	320	1.8 x ~~10^{4}~~ 10^{-4}
3/20	1306	40	600	750		
3/21	1396	41	650	800		
3/22	2705	120	1800	2200	570	1.4 x ~~10^{4}~~ * 10^{-4}
3/23	2600	400	3100	3010		
3/24	2885	400	2500	3000	670	1.8 x ~~10^{4}~~ * 10^{-4}
3/25	2877	400	3000	4000		
3/26	2715	350	2800	3300		
3/27	2779	380	3000	3800		
3/28	2762	390	4500	3900		
3/29	2791	400	3000	3800	920	1.7 x ~~10^{4}~~ * 10^{-4}
3/30	2342	210	2500	2900		
3/31	* 2825 ~~2725~~	400	4000	3000		
4/1	3273	620	6200	7500		
4/2	3247	700	6000	9000	1600	2.0 x ~~10^{5}~~ * 10^{-4}
4/3	3167	500	6000	8000		
4/4	3157	700	6000	7000		
4/5	3160	500	5000	7000		
4/6	1932	170	3400	3000		

Setpoints:

Pretreatment Hi 3,000 mR/hr based on 3.4 x 10^5 µci/sec T.S. 3.11.2.7 limit
Hi-Hi 5,000 mR/hr based on Post Treat Hi-Hi-Hi alarm setpoint

Post treatment Hi 50,000 cps Controls Bypass valve
Hi-Hi 100,000 cps Alert Level
Hi-Hi-Hi 1,000,000 cps Isolates Offgas System

* All corrections per telecon M.A. Ring with M.S. Turbak 4/25/88 MARing

5. <u>Submit to NRC Region III a formal report of your findings and conclusions within 30 days of receipt of this letter.</u>

This letter with the above four responses and the responses to the additional sets of questions in Attachments B, C, and D, contained herein fulfills this requirement.

ATTACHMENT B

COMMONWEALTH EDISON COMPANY RESPONSE TO

NRC AIT QUESTIONS ON MARCH 18, 1988

Following are Commonwealth Edison Company's response to the initial set of five (5) questions provided by the NRC Augmented Inspection Team on March 18, 1988.

(1) Are the existing procedures and instructions of GE SIL 380 adequate?

Procedures

(a) Time available for operator action -

Oscillations started within 5 minutes of pumps trip. Discussions during procedures development had estimated that 15 minutes would be available before the effects of the feedwater transient led to instability.

Justification for Adequacy of Manual Actions

Q(1)(a)(i) Immediate response to rod insertion has been the claimed response to previous events and tests of reactor stability. Can this be documented in terms of number of rods inserted, worth of rods inserted - selection and insertion procedures, and time from the start of the rod insertion decision until oscillations were terminated?

A(1)(a)(i) A review of stability experience was made with specific emphasis on operator actions in relation to the onset of oscillations. The events are split between special stability tests and events which occurred during normal plant operation. Of the four events which occurred during normal plant operation, three occurred at plants where SIL-380 recommendations had not been incorporated. Each event is briefly described in the following pages with particular emphasis on actions which started the oscillations and how the oscillations were mitigated. Table 1 provides a summary of the events.

In general, cases where oscillations were caused by the gradual withdrawal of control rods (as done during a normal startup sequence), the suppression of the oscillations required minimal control rod insertion (typically 1-8 rods inserted 0.5-1.0 foot) over a short time period (several minutes or less). Most of the successful actions also involved the insertion of relatively deep control rods (notches

08-20) which typically have the most affect on reducing core power. The major exception to this observation occurred when the oscillations were caused by a substantial withdrawal of a single control rod with the ensuing action only partially reinserting the control rod. Because of the flow biased neutron flux scram for the plant, an automatic scram occurred when the APRM oscillation magnitude reached 15% of rated peak-to-peak. For the cases caused by flow decreases, both control rod insertion and core flow increase proved to be adequate mitigating actions.

Based on the above experience, most oscillations should be readily mitigated by inserting several (4-8) deep control rods up to one foot. These actions would take only several minutes to perform and in many cases less action and time would be required. These actions are consistent with the CECo use of CRAM rods to reduce power following a LFWH or recirculation pump trip. For events where core flow increase is readily available, operational experience has also demonstrated that this is a viable method for easily mitigating oscillations.

1. Vermont Yankee (VY) - Test (1981)

VY was operating at the rated rod line and minimum forced circulation flow when both recirculation pumps were tripped during a stability test. The flow coasted to natural circulation and limit cycle oscillations of approximately 5-6% of rated, peak-to-peak were observed on the APRMs and LPRMs. Data were taken for several hours at this condition, during which the APRM oscillations increased to a peak of 10.8% peak-to-peak. LPRM oscillation magnitude was similar to the APRM oscillation and no LPRM alarms were received. During this time period, the core average power also increased (about 0.5% of rated). Six (6) control rods (notch 14-26) rods were each inserted one notch (6") and the oscillations returned to normal, <3% peak-to-peak. Exact timing of control rod insertion is not known but approximately two minutes would normally be required to insert the above described control rods.

2. BWR/4 - Operation (1982)

The plant was being started up at minimum forced circulation flow with the operator withdrawing control rods to reach the rated rod line. The operator withdrew a control rod seven feet in 70 seconds and immediately noticed large oscillations on the APRMs and LPRMs (>10% peak-to-peak). A TIP trace was initiated and 30 seconds later the rod was only partially reinserted (1.5 feet). A neutron flux scram (flow biased) occurred 30 seconds later (one minute after completion of rod withdrawal) with the APRM peak oscillation at 60% of rated. Oscillation magnitudes at the time of the scram were 15% peak-to-peak on APRMs and 40% of scale peak-to-peak for LPRMs. No LPRM alarms occurred. SIL-380 recommendations had not been incorporated at the time of the event.

3. <u>BWR/4 - Operation (1983)</u>

The plant was operating at 74% power and 66% flow, approximately on the rated rod line when a single recirculation pump trip occurred. The flow coasted down to approximately 38% of rated (near the minimum forced circulation flow for two loops operating). Two minutes after the pump trip, a loss of feedwater heater event occurred and reactor core thermal power begin to increase as feedwater temperature reduced. Four minutes after the pump trip, reactor power had increased to 59% of rated with feedwater temperature down to 300°F. At this time APRM alarms were received and the APRMs were observed to be oscillating at approximately 10% peak-to-peak. Five and one half (5.5) minutes after the pump trip a single control rod was inserted from the fully withdrawn position. An APRM flow biased flux scram occurred 30 seconds later (six minutes following the pump trip) at approximately 70% of rated flux. The APRM oscillations reached 25% peak-to-peak and no LPRM alarms were received.

4. <u>BWR/4 - Test (1983)</u>

The reactor was being operated at natural circulation conditions with power at 52.4% of rated. Control rods were being withdrawn when APRM oscillations of 5% peak-to-peak were noted. Control rods were withdrawn further until APRM oscillations were noted to increase. Oscillation magnitude continued to increase for approximately 5 minutes and stabilized at 12% peak-to-peak for APRMs and 60% peak-to-peak for LPRMs (no LPRM alarms). Four to eight control rods (positions unknown) were then inserted one notch (6") and the oscillation magnitude returned to normal (<5% peak-to-peak).

5. <u>BWR/6 - Test (1984)</u>

The reactor was being operated at natural circulation conditions with power at 45% of rated. Control rods were withdrawn until oscillations were noted on the APRMs and LPRMs. Over a five minute period, LPRM oscillations were observed to increase from 5% to 28% of scale peak-to-peak (no LPRM alarms). During this same time, the APRM oscillations increased from 2% to 9% of rated peak-to-peak. Control rods were then inserted (exact number and insertion not known, but time period indicates only several rods inserted several notches at most) and recorded traces showed the oscillation magnitudes decreased by approximately 33% over a 40 second period from the time of peak magnitude and start of control rod insertion. No additional traces were available but test crew observation was that oscillations rapidly diminished in magnitude following the control rod insertion.

6. BWR/6 - Test (1984)

The reactor was being operated at minimum forced circulation (minimum valve position, pumps at high speed) with control rods being withdrawn until oscillations were observed. Over a two minute period, the LPRM oscillations grew from 5% to 15% of scale, peak-to-peak (no LPRM alarms) and the APRMs grew from 2% to 4% of rated, peak-to-peak. Several control rods were then inserted (exact number and insertion not known, but time indicates only several rods inserted several notches at most) and recorded traces showed the oscillation magnitude decreased by approximately 50% over a one minute period from the time of peak magnitude and start of control rod insertion. No additional traces were available but test crew observation was that oscillations rapidly diminished in magnitude following the control rod insertion.

7. BWR/6 - Operation (1984)

The reactor was being operated with the recirculation flow control valves (FVC) partially open and pumps at low speed as part of a training startup during the initial test program. Reactor power was approximately 53% of rated and no feedwater heating existed because the turbine was offline and steam bypass was being used. BOF transient initiated a runback of FCVs and oscillations were immediately observed on the APRMs and LPRMs. The magnitude of APRM oscillations grew from 3% to 25% of rated peak-to-peak in two minutes and LPRM alarms on several detectors were noted during the oscillations. The operator was instructed to manually scram the reactor two minutes after the oscillations began. SIL-380 recommendations had not been implemented prior to the event.

8. BWR/6 - Test (1984)

The reactor was being operated with the FCVs at 30% position with the recirculation pumps at low speed during special stability tests. Reactor power was 50.9% of rated with approximately 40°F temperature decrease from normal due to the intentional bypassing of feedwater heaters during the test. Oscillations were observed on the LPRMs of 12% of scale peak-to-peak (no LPRM alarms) with APRM oscillations of3% of rated peak-to-peak. With four deep (notch 08) control rods inserted two notches each (1 foot) the reactor was stable (estimated time to insert control rods is 1-2 minutes).

9. BWR/6 - Test (1984)

The reactor was being operated along the maximum extended rod line (approximately 120% rod line) with the recirculation pumps at low speed and FCVs at approximately the 30% position. The FCVs were closed to the 23% position and oscillations were observed on the APRMs and LPRMs. The FCVs were then closed to the minimum position and the oscillation magnitude was observed to increase. The peak LPRM oscillation magnitude was 35% of scale (no LPRM alarms) with an APRM oscillation magnitude of 5% of rated peak-to-peak. Operation continued at this condition for 15 minutes with no change in character of the oscillations. The operator then slowly opened the FCVs to 50% position (5 minutes) and the oscillation magnitude was observed to slowly decrease as flow increased. At 50% FCV position the flux noise had returned to normal.

10. BWR/3 - Operation (1985)

The reactor was being started up along the minimum forced circulation line at approximately 55% of rated power. During control rod withdrawals, oscillations were observed on the APRMs of approximately 5-10% of rated peak-to-peak. Two relatively deep control rods (notch 20) were inserted one notch (6") each and the APRM magnitude returned to normal (less than one minute for control rod insertion and oscillation reduction). Withdrawal of different control rods again resulted in APRM oscillations, this time with a magnitude of approximately 10-15% of rated peak-to-peak. Seven shallow (notch 46) control rods were inserted one notch (6") each and the oscillations were mitigated (control rod insertion took less than five minutes). Once again a different control rod was withdrawn and oscillations were again observed on the APRMs of 10-15% of rated peak-to-peak. One deep control rod (notch 02) was inserted one notch (6") and the oscillations were mitigated (control rod insertion took much less than one minute). Core flow was then increased approximately 5% of rated and control rods were successfully withdrawn to the desired rod pattern. SIL-380 recommendations had not previously been incorporated into plant procedures.

Q(1)(a)(ii) How can the reliability and effectiveness of the manual insertion procedures be improved?
Considerations -
- Select __________ rods for insertion sequence which typically takes _x_ minutes after two pump trips or _y_ minutes after observed violation of stability acceptance criteria. If instability is observed after completion of this initial process, manual scram should be required.
- Restart recirculation pumps if permissive light is available to show that all permissives have been cleared (viable?).
- Consider the use of an on line stability monitor (similar to the ORNL noise algorithm) for more rapid and reliable surveillance of approach to instability.

A(1)(a)(ii) Response (1)(a)(i) addresses the issue of the effectiveness of deep control rod insertions. The response below addresses LaSalle's procedure to rapidly insert control rods.

CRAM rods are designated per LAP 100-13 (Step F.3) for emergency load reduction to ". . . strongly reduce the operating flow control line to avoid a reactor scram." The associated rods are designated on Attachment G of LAP 100-13, and kept with the control rod sequence package. These rods are also flagged with small strips of RED translucent tape placed on the appropriate rod select buttons. The operators are instructed to continuously insert each CRAM rod to position 00.

After the operator has inserted all CRAM rods, he will go through the applicable sequence steps (which are listed on Attachment G and denoted on the sequence pages with "CRAM" next to the step) and initial the INSERT column(s). Upon completion of these actions, the operator will resume rod insertions at the back of the sequence, if needed.

The proper choice of CRAM rods is highly dependent on the existing rod pattern, and these rods cannot be permanently designated. Some situations require that the operator does NOT have CRAM rods available (especially low power, near the Rod Worth Minimizer Low Power Setpoint). Because of this, the Qualified Nuclear Engineer issues Attachment G and verifies the application of the tape to the correct rods. The general criteria for CRAM rod designation is that the CRAM rods are deep rods (BPWS groups 9 or 10), and are at positions between 08 and 24. The number of rods designated varies but is usually chosen to achieve from 6 to 12 percent rod line reduction.

Assurance that the CRAM rod tape is correct is obtained daily during performance of the Nuclear Engineers Daily surveillance LTS 1200-4. A procedure step and surveillance sheet checkoff verify that the CRAM rods are correctly specified both on the panel (buttons) and in the sequence package. This is to ensure that the operator will not inadvertently insert the wrong rods.

As recommended in SIL 380, control rod insertion is the preferred method of leaving the region where there is marginal room to stable operation while in natural circulation. LaSalle procedures have been modified to reflect this. LaSalle is evaluating the installation of a permissive light for recirculation pump restart. LaSalle is also evaluating several different types of stability monitors. No decisions on these plant modifications have been reached at this time.

Q(1)(a)(iii) How can the adequacy of automatic scram protection be demonstrated?
- Can it be shown by analyses that inherent shutdown mechanisms such as Doppler will limit, the peak, power level
- even under conditions of regional oscillation such that safety limits will not be violated before 118% power APRM scram occurs. What are the limitations of the analysis in terms of fuel design applicability or other factors?

A(1)(a)(iii) This issue is being discussed with the Boiling Water Reactor Owner's Group (BWROG). Commonwealth Edison will inform the NRC on developments and schedules as they occur. A status report will be provided by July 1, 1988.

Q(1)(b) In view of the ATWS implications of the LaSalle Unit 2 incident, review the generic stability analysis in the ATWS report. Address the adequacy of the ATWS resolution, i.e., recirculation pump trip, considering that LaSalle 2 could not have tripped on return to 118% power. Do the ATWS assumptions consider the implications of regional instability?

A(1)(b) The 1979 GE Generic ATWS report, "Assessment of BWR Mitigation of ATWS" (NEDE-24222), addresses stability related oscillations associated with a postulated ATWS event. This report specifically investigated the sensitivity and potential impact of limit cycle oscillations on fuel integrity. Limit cycle neutron flux oscillations up to 500% of rated bundle power were analyzed (since no scram occurs, whether the oscillations are regional or core wide is irrelevant, the maximum amplitude is the important parameter). The fuel clad temperature response was evaluated assuming the fuel was already in boiling transition due to the ATWS event. The resulting peak-to-peak fuel clad temperature variation was 130°F for a limit cycle frequency of 0.125 Hz, decreasing to 50°F for a frequency of 0.25 Hz. Since the limit cycle frequency in a BWR is typically 0.3-0.5 Hz, the calculated temperature response is conservative. Even with this conservatism, it was concluded that fuel integrity is not significantly affected by the limit cycle induced temperature variations.

The potential for limit cycle oscillations during an ATWS event was recognized by the NRC as a result of the GE assessment and oscillations observed at an operating BWR. GE provided several additional technical presentations to the NRC staff and ACRS expanding upon the NEDE-24222 conclusion that the fuel thermal duty was not severe. It was also shown that even if prolonged exposure to limit cycles resulted in a loss of clad integrity, the failure would not impact the ability to cool the core and any incremental radiological consequences would be small and bounded by the generic ATWS assessment. Given the importance of the recirculation pump trip (RPT) in minimizing the energy deposited in the pressure suppression pool (thereby maintaining containment pressure within limits) during an ATWS event, the GE analysis demonstrated that the potential consequences of oscillations during an ATWS event are acceptable. When the NRC issued their standards for the reduction of risk from ATWS events (Federal Register/Vol. 45., No. 226/November 24, 1981) the possibility for oscillations following the RPT was specifically noted in the context of, "given a trip of the recirculation pumps ... a static or oscillatory equilibrium will be maintained ...".

Based on the above, it is concluded that the potential for limit cycle oscillations during an ATWS event has been thoroughly reviewed by the NRC in arriving at the ATWS rule (10 CFR 50.62), specifically the requirement for RPT. Furthermore, the analysis specifically considered very large oscillations which have been hypothesized to be possible during regional instabilities.

Q(1)(c) The predicted decay ratio for LaSalle 2 Cycle 2 was 0.60. Based on results of the recent incident, it seems clear that both LaSalle 1 and 2 are potentially unstable in natural circulation. Therefore, we will require that procedures and Tech Specs required by GL 86-02 be implemented on both units (as if DR > 0.80). Evaluate and explain why there was 40% error in the predicted decay ratio. How can we continue to rely on calculations to demonstrate stability? Should GL 86-02 requirements apply to all BWR's without waivers by calculations?

A(1)(c) To clarify the condition of the reactor following the recirculation pump trip on March 9, 1988, at LaSalle-2, a specific analysis using actual plant data recorded during the event was performed. Because the conditions following the pump trip were not at steady state, sensitivities to the parameters which were varying (core power, core flow, core inlet enthalpy, power distribution) were evaluated. Preliminary calculations predict core decay ratios varying between 0.79 and 0.92. For all cases analyzed, the channel decay ratios were less than 0.53. Since it is known from plant data that the stability of the core was varying during the time following the pump trip (stable for the first five minutes, varying degrees of instability from five to seven minutes following the pump trip) these preliminary calculations are consistent with the observed behavior of the plant.

Also, the core-wide instability observed is consistent with the high core decay ratio and relatively low channel decay ratio.

Available sensitivity studies indicate that variations in total core flow and power distribution had the most effect on the stability margins. From STARTREC traces recorded during the oscillations, the core flow varied by as much as 3% of rated with a minimum indicated flow of approximately 27% of rated. This value is 3% of rated below the value assumed in the licensing calculations and is a large contributor to the reduced stability margins at the actual plant conditions.

Because the reactor was not at steady state conditions following the pump trip, considerable uncertainty in the state variables exist. Therefore, additional calculations are currently being performed to better assess the sensitivity of the core decay ratio to these uncertainties. However, based on the preliminary calculations discussed above, decay ratios indicative of limit cycle oscillations were predicted for LaSalle-2 at the conditions experienced following the pump trip event. The primary difference between the licensing predicted decay ratio and the actual decay ratio can be attributed to the transient conditions that resulted following the pump trip.

Final calculations will be provided to the NRC when they become available. We anticipate submittal of the final analyses by May 15, 1988.

Q(1)(d) LaSalle 2 has very limited capability to record LPRM traces and other data that would be needed to evaluate possible violation of safety limits if regional oscillations were to occur. Discuss the adequacy of existing instrumentation and recording capability (LPRM alarms, operator observations and automatic recording, etc.) for evaluation of such events as discussed in SIL 380, item 9.

A(1)(d) Two LPRMS will be input into Startrec. The general question on the adequacy of plant instrumentation will be addressed through the BWROG. At this time, Edison expects to update this response by July 1, 1988.

Q(1)(e) Address the effects of cold water insertion on restart of recirc pumps after loss of feedwater heaters and two pump trips. Also address the effects on power distribution of inserting rods prior to the recirc pump start. Is the selected configuration for CRAM rods the same as for LoFWH procedures? Have rod blocks been considered in the selection?

(A)(1)(e) During natural circulation operation of a BWR, the mass flow rate of saturated fluid from the steam separators is four to five times greater than the mass flow of feedwater entering the vessel. The feedwater mixes with the saturated fluid in the downcomer region of the vessel and is then drawn through the jet pumps and into the core as a result of the natural circulation process. As colder feedwater enters the vessel, it mixes with the saturated fluid and a gradual decrease in core inlet temperature occurs. As this fluid passes through the core during natural circulation conditions, a gradual increase in core average power occurs. Under these conditions, the restart of a recirculation pump will not result in a cold water insertion event for the core. The water entering the core after the pump is started is no colder than the water entering the core during natural circulation conditions. Therefore, the core response is only affected by the increased core flow rate (which sweeps voids from the core resulting in a reactivity increase) caused by the pump start. A more limiting condition exists when the fluid in the recirculation loops is at a much lower temperature than the fluid in the downcomer region. If a recirculation loop is started under these conditions, the reactivity increase can be attributed to the sweeping of voids from the core caused by the increased core flow rate and to the reduced temperature of the recirculation loop fluid as it is swept into the core. Under these conditions, the core does experience a cold water insertion because of the lower temperature of the recirculation loop which had not been mixing with the downcomer fluid prior to the pump start. This event is explicitly analyzed in the FSAR and the consequences are negligible (MCPR remains substantially above the safety limit MCPR). Therefore, the affects of starting a recirculation pump after loss of feedwater heaters and a two pump trip is bounded by the FSAR analysis for idle recirculation loop startup.

Selection of control rods in the CRAM array used to reduce power following a two pump trip is based on achieving approximately a 10% reduction in the rod line while minimizing the effect on power distribution and future rod movement. In general, deep control rods are chosen and can be fully inserted with minimum impact on core peaking. These deep rods can provide the necessary power reduction and are not difficult to return to their original position following pump restart. Although some increase in peaking will occur, the power reduction capability of the CRAM rods justifies this technique for use in conjunction with SIL-380 recommendations following a two pump trip. In accordance with normal operating practice and procedures, the operators will consult with the station nuclear engineers prior to power increases following control rod motion, i.e., insertions of CRAM rods. At that time, peaking would be assured to be within acceptable limits prior to restarting the recirculation pumps.

The selected configuration for the CRAM rods is the same as for the LFWH procedures. Rod blocks do not have to be considered in the selection of the CRAM rods since no control rod blocks will occur during rod insertion at the power levels where the CRAM rods would be used.

(2) Are the Technical Specifications adequate?

Q(2)(a) What is the frequency of 2 pump trip with reactor remaining at power? (Should manual scram above the 80% line be a permanent requirement?)

A(2)(a) General Electric has no rigorous value for the frequency of two recirculation pump trips that is based on a complete review of actual plant experience. GE internally used a value of 0.25 events per plant year. However, review of the basis for this number indicates that this is only an estimated value and is not based on actual plant experience. Because recirculation pump trips do not always result in a reactor scram or significant unavailability, these events are not necessarily available in existing databases. A review of readily available information has identified at least four dual recirculation pump trips in the last five years, three of which did not result in an automatic scram caused by the pump trip. However, these results are provided for information only since a rigorous review of plant experience was not possible.

(NRC Question in parentheses was identified only as an NRC comment and therefore does not require a response. The current belief of the BWROG is that control rod insertion is an adequate and appropriate response to two pump trips.)

Q(2)(b) Technical Specification Changes will be required for LaSalle Unit 1 prior to restart. Technical Specification Changes for LaSalle Unit 2 should be submitted within 30 days. Manual scram will be required from above the 80% rod line until relief of this requirement is obtained.

A(2)(b) Technical Specification Changes for both units are being prepared to fully implement SIL 380. The proposed changes will not require scram, unless flux oscillations are observed.

The proposed Technical Specification (TS) divides the recirculation loop operability requirement (TS 3.4.1.1) from the thermal hydraulic stability requirement (TS 3.4.1.5). Both topics were previously covered under TS Section 3.4.1.1. Proposed TS Section 3.4.5.1, Thermal Hydraulic Stability, allows operation in the following three conditions: 1) with core flow greater than or equal to 45% of rated, or 2) with thermal power in the allowable region, or 3) with thermal power in Region 2 and acceptable APRM/LPRM noise.

The actions for failure to meet the LCO are divided by region of operation. In Region 1, with one or more recirculation loops in operation, Region 1 must be left within two hours using either control rod insertion or core flow increase. In Region 1, with no recirculation loops in operation, control rods must be inserted to reduce the thermal power below 36% of rated. If the LPRM/APRM noise levels exceed 10%, the reactor is to be scrammed. Failing to meet the above for no recirculation loops, the reactor is to be placed in hot shutdown within six hours.

In Region II and with reactor noise beyond acceptable limits, immediate action is to be taken to make the noise level acceptable. In the next two hours, Region II must be left for the allowable region. This may be accomplished using either control rod insertion or core flow increase.

The surveillance requirements apply only to operation in Region II. APRM/LPRM noise must be checked to see that it does not exceed the larger of three times the established baseline or 10% peak-to-peak. The surveillance is to be performed at least once per twelve hours and within 30 minutes of entering Region II after a 5% power increase. The core flow must also be verified to be greater than or equal to 39% at least once per twelve hours.

Q(2)(c) Resolution of the wording on response to two pump trip or exceeding surveillance criteria is needed.

Susquehanna wording is acceptable to staff. Staff considers that "Immediately" implies prompt response commensurate with other high priority actions for the event.

A(2)(c) See Response (2)(b).

Q(3) Staff is interested in simulator changes as a result of the event and wish to be kept informed of progress.

A(3) Software engineers are actively pursuing a method of demonstrating the oscillation phenomena experienced by the low flow/high power condition during the March 9 double recirculation pump trip at LaSalle.

To date, APRM indicators are capable of displaying oscillations such as experienced, LPRM high alarms are capable of oscillating in and out. Additional work is being done to simulate localized oscillations to reflect the local power/flow relationship.

Additionally, a scenario has been drafted to use for training and demonstration of a 1 or 2 pump trip condition. It is expected that modeling will be completed for use in training by July 1, 1988.

Q(4) Where is the applicable analysis for this event? Describe the analysis performed and its applicability.

A(4) As discussed with the AIT members during the exit meeting, NEDE 24011 describes the analyses performed for stability events.

Q(5) There is a concern regarding the accuracy, timeliness, and effectiveness with which pertinent information on this event was reported to the NRC. While the requirements of 50.72 regarding immediate notification were satisfied, information regarding the neutron flux oscillations was not promptly reported to the staff. CECo is requested to address this concern including the adequacy of the existing reporting procedures and any revisions that may be necessary to preclude any delays and pertinent information for future potentially significant events that may occur.

A(5) LaSalle has reviewed the requirements of 10CFR50.72 as they apply to the event of March 9, and believes that the only applicable category was the 4 hour report for the RPS actuation required by b.2.ii. In fact, the call was made within one hour. At this time the oscillations were still being examined, although not by the individual who made the notification. Subsequent review did not determine that any unexpected events occurred. Several conversations were held with Region III personnel regarding the observation of flux oscillations.

1.a.i

TABLE 1 - SUMMARY OF OPERATOR ACTIONS

		INCEPTION MAGNITUDE		PEAK MAGNITUDE				ACTION TAKEN					
								RODS INSERTED					
#	INITIATOR	APRM[a]	LPRM[b]	APRM	LPRM	LPRM[c] ALRM	TIME[d] TO PEAK	#	FT	POS	TIME[e]	EVENT TERMINATION	TIME[f] AFTER ACTION
1	FLOW	5-6	5-6	11	10-15	N	2 h	6	0.5	D[g]	2 h	SAME	2 m
2	RODS	10	-	15	40	N	1 m	1	1.5	S	30 s	AUTO SCRAM[h]	30 s
3	FLOW/LFWH	10	-	25	-	Y	2 m	1	12.	S	1.5 m	AUTO SCRAM[h]	30 s
4	RODS	5	20	12	60	N	5 m	4-8	0.5	-	5 m	SAME	2 m
5	RODS	2	5	9	28	N	5 m	4-8	0.5	-	5 m	SAME	2 m
6	RODS	2	5	4	15	N	2 m	4-8	0.5	-	2 m	SAME	2 m
7	FLOW	3	-	25	-	Y	2 m	-	-	-	-	MANUAL SCRAM	-
8	RODS	3	12	3	12	N	1 m	4	1.0	D	1 m	SAME	1 m
9	FLOW	3	10	5	35	N	30 m	FLOW INCREASE			30 m	SAME	< 5 m
10	RODS	5-10	-	5-10	-	N	-	2	0.5	D	-	SAME	1 m
	RODS	10-15	-	10-15	-	N	-	7	0.5	S	-	SAME	5 m
	RODS	10-15	-	10-15	-	N	-	1	0.5	D	-	SAME	< 1 m

a APRM magnitude in % of rated, peak-to-peak
b LPRM magnitude in % of scale, peak-to-peak
c LPRM upscale alarms, Y - alarms occurred, N - no alarms received
d Time from inception of oscillations
e Time from inception of oscillations
f Time from start of action (most cases estimated from observations and time to complete action)
g D - deep rods ($\leq$ notch 24), S - shallow rods (> notch 24)
h Flow Biased Neutron Flux Scram (setpoint is 60-70% of rated)

ATTACHMENT C

COMMONWEALTH EDISON COMPANY'S RESPONSE TO NRC AIT QUESTIONS ON MARCH 23, 1988

Following are Commonwealth Edison Company's responses to the second set of seven (7) questions provided by the NRC AIT on March 23, 1988.

Q.1 Startrec was necessary to analyze the event. What parameter should be used to trigger if a similar event occurred?

A.1 The Startrec information provided valuable information which, if not available, would have complicated and delayed the analysis of the event. This would be a CECo liability, but availability of Startrec information is not a plant design or operational requirement. The Sentinel work file was configured to initiate if APRM exceeded 112% neutron flux indication, rising. The lack of a trip on this parameter during the transient was considered as further indication that the 118% flux scram setpoint had not been challenged at any time other than when the scram occurred. Also see Response (1)(d) in Attachment B.

Q.2, 3 Does the LPRM alarm filtering affect the ability to detect oscillations? What indication keyed the operators that oscillations were present.

A.2, 3 The operators noticed the oscillations because of the swings of the APRM recorders. During the post-trip review, the conclusion was made that the flux oscillations started when the LPRM downscale alarms began cycling every 2 seconds. Only 3 annunciator inputs are time filtered (APRM HI, LPRM HI, ROD BLOCK). The LPRM Downscale alarm is not time filtered. The time filtering of less than 0.1 seconds on the LPRM HI is not considered to be a significant obstacle to detection of instabilities. LPRM and APRM flux signals are used as the primary indicators of instability. The annunciators are used as possible keys to cause the operator to go check the APRM and LPRM meters at times when he might not normally do so.

Q.4 The NRC takes exception to the statements in the LaSalle On-Site review that the NRC and GE agree that this phenomenon is not a safety concern. Fear was expressed that this statement might encourage operators to treat this as a trivial event.

A.4 GE Topical report NEDE-24011 presents the analysis of oscillations and the conclusions that this phenomenon will be terminated by a high flux scram without any fuel damage occurring. In 1985 the NRC issued a SER accepting the GE report and its conclusions, and accepted NEDE 24011 for reference in licensing submittals. This apparent bounding of the effects of oscillation is what led to the statement that there were no safety concerns. However, the lack of safety concerns by no means implies that this is not a significant event. We believe, for instance, that because of the detailed analyses done, a Design Basis Accident (DBA) is not a safety concern, because the plant and public are protected. Even though there is no safety concern, the DBA is not treated as a trivial event. Nor is the existence of oscillations. The shift briefings, delayed startup, mandatory scram requirement, and other procedural changes have already served to highlight the significance of the event. Discussions with the training department ensure that this wording will not be misconstrued in future training sessions.

Q.5 What is indicated power at time of LPRM HI alarm?

A.5 At steady state conditions, an LPRM indication of 100 is calibrated to equal the fuel LHGR limit. For all of the LaSalle 2 Cycle 2 fuel, this is 13.4 KW/ft. Subsequent to the AIT exit, CECo reviewed the LPRM setpoints and determined that the LPRM HI alarm setpoint is 100% of scale. At the LPRM HI alarm setpoint, the thermal heat flux is not equal to 13.4 kw/ft. when the LPRM HI alarm occurs because of the thermal time constant of the fuel. The duration of the LPRM HI alarm cannot be rigorously used to determine the length of time that the neutron flux exceeded a reading of 100 because the alarm actuates if ANY LPRM is in alarm. Therefore, the first LPRM to exceed 100 will initiate the alarm and the last one to go below 100 will allow it to reset. Even so, it can be seen that the duration of the LPRM HI alarms is generally less than 150 milliseconds.

Q.6 What was the core maximum peaking factor at the time of the event?

A.6 The normally scheduled Core Performance Log (P1) printed at 1600 on 3-9-88 (1.5 hours before the event). The peaking factor was + 2.112 ("Design" peaking factor is 2.408). Since the unit was at steady state up to the event, the number correctly specifies the peaking factor at the time of the event.

Q.7 Have CRAM rods and stability monitoring rods been "taped"?

A.7 Yes

ATTACHMENT D

COMMONWEALTH EDISON COMPANY'S RESPONSE TO
NRC AIT QUESTIONS ON MARCH 24, 1988

Following are Commonwealth Edison Company's responses to the third set of three (3) questions provided by the NRC AIT on March 24, 1988.

Q.1 Power Distribution - LPRM alarms occurred at an APRM level of 87 percent. This implies a shift in power distribution, since there should normally be substantial margin to the high LPRM level when APRM level is at 100 percent. Provide the available information on power distribution prior to the event and explain why LPRM alarms were triggered at the 87% APRM level. Is the LPRM Hi setpoint level equivalent to 105 watts/cm? Is it based on the allowable LHGR or simply to indicate that the instrument is off scale?

A.1 Summary

The occurrence of LPRM Upscale and Downscale alarms during the LaSalle-2 instability are consistent with the expected response of the core based on the APRM response. Because of a shift in power distribution following the recirculation pump trip and the phase relationship between LPRMs at different axial locations, LPRM alarms occurred at lower APRM levels than would be expected during steady state operation. The increase in power distribution was caused by the reduction in core flow following the recirculation pump trip which moves the boiling boundary lower resulting in a more bottom peaked axial power distribution. The phase relationship between the LPRM levels is a result of the density wave oscillation that is causing the core nuclear-thermal/hydraulic instability. Perturbations in coolant density must travel the length of the channel and therefore the neutron flux response to the perturbations is delayed in time at the higher levels in the core. These two factors are shown to explain why the LPRM alarms were triggered at the 87% APRM level.

Evaluation

Figures 1 and 2 show the raw LPRM readings before the recirculation pump trip and just prior to the onset of oscillations. As noted above, there indeed was a shift in power distribution during the event, but the shift was caused by the reduction in core flow caused by the pump trip. This shift in the axial power shape towards the bottom of the core is a typical occurrence for a flow decrease. The primary cause of the shift is the lowering of the boiling boundary at the reduced core flow rate. As shown in Figures 1 and 2, the peak to average LPRM reading increased from 1.31 to 1.64 as a result of the flow decrease. This shift in power distribution alone is a major contributor to why the LPRM alarms were triggered at the 87% APRM level.

Another factor that must be considered in the relationship between the LPRM and APRM signal is the phase lag that occurs from the bottom to the top of the core during density wave oscillations. Since the oscillations are caused by a perturbation in the coolant density, the effect of the perturbation must travel up the channel before impacting the higher level LPRMs. This propagation of the perturbation causes a phase shift between the signals at the four LPRM levels. The effect on the APRMs is that each LPRM level does not react its peak at the same time and therefore the APRM to LPRM relationship during these transient conditions is not the same as it would be during steady state operation. Figure 3 shows an example of how the phase relationship affects the APRM to LPRM relationship. Four LPRMs (Levels A, B, C and D) are assumed to be oscillating with the same magnitude but 90° out of phase (A to D level). The average of the four signals (indicative of what an APRM signal would do) oscillates at the same frequency but its peak magnitude is not as high as the peak of each individual LPRM since the four peaks do not occur at th same time. However, since the LPRMs are indicating a true phase lag between the oscillations at different axial locations, the APRMs are correctly measuring the core average neutron flux during core wide oscillations.

An analysis has been performed for the LaSalle-2 conditions at the onset of oscillations. The response of the LPRMs assigned to APRM Channel A have been modeled by a higher order sine wave (necessary to match the known non-linear characteristics of the oscillations). The LPRM with the highest average reading is assumed to oscillate up to 100% of scale (LPRM Upscale alarm setpoint) and the remaining LPRMs in APRM Channel A are assumed to oscillate with the same relative magnitude. This assumes that the peak-to-peak magnitude normalized to the average value is relatively constant for all LPRMs in the core (i.e., no shift in "peaking" during the oscillations). This assumption has been previously proposed and supported by data from the Vermont Yankee Stability tests. For the LPRM levels above the boiling boundary (B, C and D), the relative oscillation magnitude is assumed to be 1.2 times the relative magnitude for the A level LPRMs to account for the increased sensitivity to density perturbations in the voided regions (higher void coefficient). This relationship was also determined from the Vermont Yankee test data.

The APRM signal is the average of the 21 LPRMs assigned to the channel with an appropriate gain adjustment determined from the known values prior to the pump trip. The phase lag between the four LPRM detector levels is based on actual test data from Caorso which shows approximately an 82° shift from the A to D level. Figure 4 shows the results of the above analysis. For the peak LPRM oscillation just up to the LPRM Upscale alarm setpoint, APRM A is predicted to reach 84.5% of rated which is very close to the value estimated from data recorded during the event. The analysis also predicts that several of the D level LPRMs will go below the LPRM Downscale setpoint (5% of scale) and that LPRM Downscale alarms should occur before the first LPRM Upscale alarm is reached. The analysis also estimates that for APRM oscillations with a peak of less than approximately 74% of rated, no downscale alarms should occur. From the Hathaway Event

Recorder, two time periods after the onset of oscillations do not have LPRM downscale alarms. Review of STARTREC data during these two time periods shows that the APRM oscillations do not exceed 74% of rated during these two periods. Therefore, these results are consistent with the observations and recordings during the event and demonstrate that the model accurately predicts the relationship between the LPRMs and APRMs during the LaSalle-2 oscillations.

For a discussion of the LPRM Hi setpoint level, see the response to Question 5 of Attachment C.

Q.2 Is the filter circuit which prevented a Power/Flow scram typical of other reactors? Since power/flow scrams have occurred for similar events in foreign reactors, justify the difference in the protective system design. Also justify the time delays on the LPRM circuitry and the operating practices to preclude LPRM alarms, which are one of the early indicators of instability.

A.2 The Simulated Thermal Power Trip (STPT) circuitry is typical of all BWR/5 and BWR/6 plants and has been retrofitted into other reactor types as shown in Table 1. The STPT circuitry processes the Average Power Range Monitor (APRM) neutron flux signal through a filtering network with a time constant which is representative of reactor fuel thermal dynamics. This signal closely approximates the average thermal power during transient and steady state conditions. The STPT is a flow-referenced trip and is independent of the 120% neutron flux trip signal. No FSAR analyses are affected by the STPT circuitry since no credit is taken for the flow-referenced STPT scram. The STPT circuitry reduces unnecessary challenges to the Reactor Protection System (RPS) caused by momentary neutron flux spikes which may be produced by flow excursions in the recirculation system, transients during turbine stop valve tests and other vessel pressure perturbations. These spurious scrams are unnecessary challenges to the RPS since the neutron flux spikes represent no decrease in fuel thermal margins, especially in the low flow regions.

Table 1 U.S. BWRs with STPT*

Brunswick 2, 3
Hatch 1, 2
Browns Ferry 1, 2, 3
Fitzpatrick
Fermi-2
Shoreham
Ham Creek
Susquehanna 1, 2
Hanford-2
LaSalle-1, 2
Nine Mile Point-2
River Band
Grand Gulf
Perry
Clinton

As discussed in the response to Questions 2 and 3 of Attachment C, the time filtering of less than 1 second on the LPRM Hi is not considered to be a significant obstacle to detection of instabilities. The filter prevents occurrence of nuisance alarms when operating at or near full power. Thus allowing the LPRM Hi alarm to remain an effective indication of high local flux.

* Based on information currently available to GE.

Q.3 It is the staff intent that technical specifications and operating procedures be designed to provide for suppression of neutron flux oscillations without reliance on high flux level (118%) scram. Unless there is reasonable expectation that this objective can be achieved, the operator should respond to instability conditions with a manual scram.

A.3 This is an NRC Staff statement requiring no specific response.

FIGURE 1 - LPRM READINGS BEFORE PUMP TRIP

AVERAGE = 51.1
MAXIMUM = 66
PEAKING = 1.31

		8	16	24	32	40	48	56
57	D		27	38	38	34		
	C		35	45	47	41		
	B		32	39	36	39		
	A		29	38	32	35		
49		30	46	52	55	47	42	
		41	59	58	64	54	54	
		42	63	60	61	56	61	
		33	60	61	62	61	50	
41		41	56	53	49	56	53	35
		50	58	59	55	63	55	41
		53	59	54	35	I	56	38
		62	58	I	55	55	59	33
33		51	52	49	49	50	49	42
		63	58	55	I	56	56	50
		56	59	55	61	57	57	37
		58	60	I	65	56	61	29
25		46	57	52	50	57	54	39
		55	62	I	60	66	56	44
		56	63	I	61	60	57	39
		64	60	58	56	56	55	36
17		36	51	54	53	57	46	28
		45	61	53	60	57	57	32
		50	67	54	61	58	63	32
		57	62	I	57	58	59	27
9			39	47	50	45	34	
			48	57	59	52	42	
			53	56	53	55	43	
			57	62	56	63	33	

I = Inoperable LPRM

FIGURE 2 - LPRM READINGS AFTER PUMP TRIP

AVERAGE = 23.2
MAXIMUM = 38
PEAKING = 1.64

57D		9	13	14	12		
C		14	17	18	16		
B		16	19	18	19		
A		18	23	20	21		
49	11	16	18	19	16	14	
	18	23	22	25	24	22	
	22	31	29	29	27	30	
	21	37	37	37	37	30	
41	14	20	19	17	20	18	12
	19	22	23	21	24	21	16
	26	29	26	27	I	27	19
	38	35	I	33	33	36	20
33	18	18	17	16	18	17	14
	24	22	17	I	21	22	18
	26	27	26	30	27	27	18
	35	35	I	38	34	36	17
25	16	20	18	17	20	19	14
	21	24	I	24	26	21	17
	27	30	I	30	30	28	19
	38	35	35	33	34	34	22
17	13	17	19	19	20	15	10
	18	23	20	23	22	21	13
	24	32	26	29	27	30	15
	34	37	I	33	34	35	16
9		14	17	18	16	12	
		19	22	23	20	16	
		25	27	25	26	20	
		33	36	32	36	19	
	8	16	24	32	40	48	56

I - Inoperable LPRM

FIGURE 3
LPRM AXIAL PHASE RELATIONSHIP

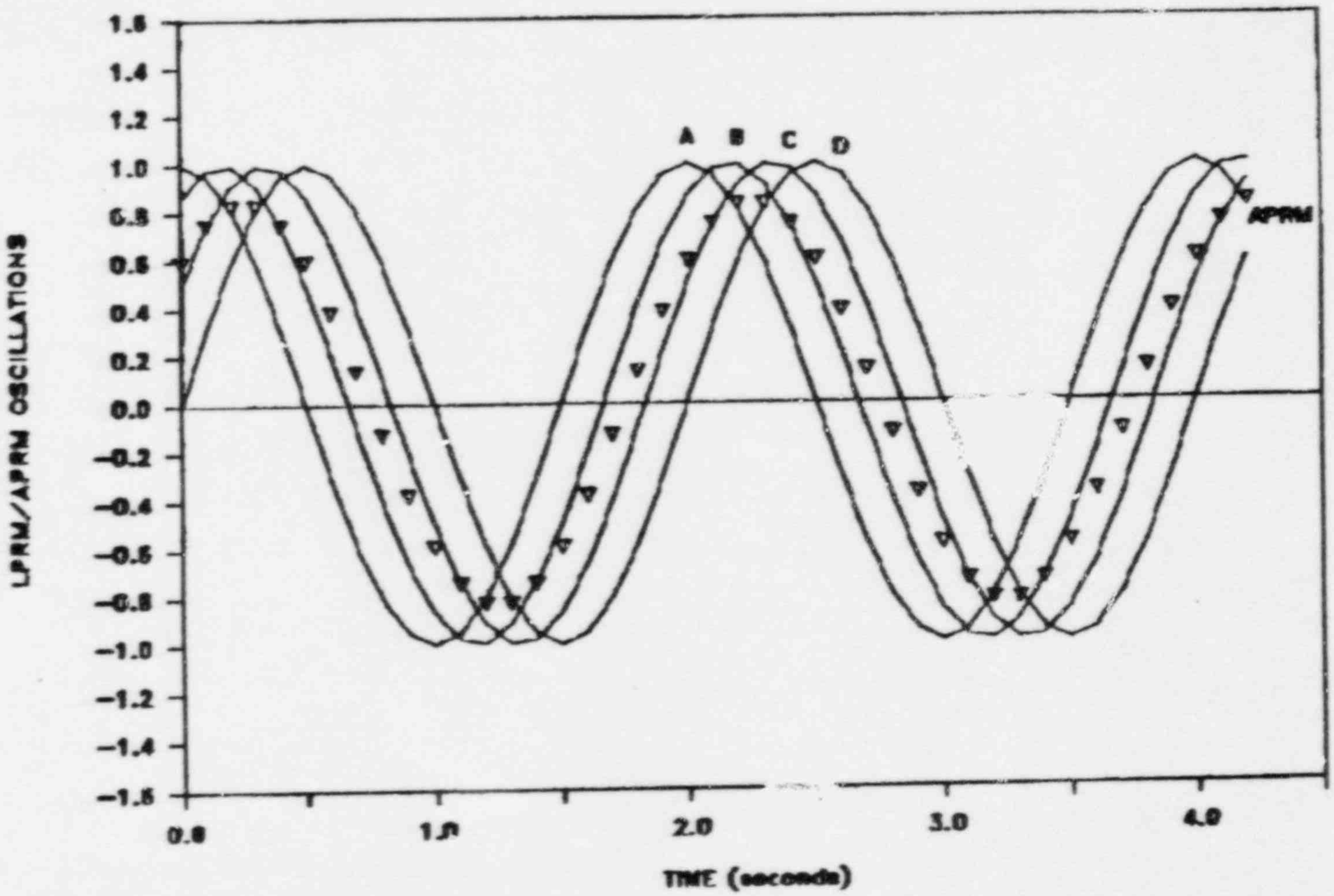
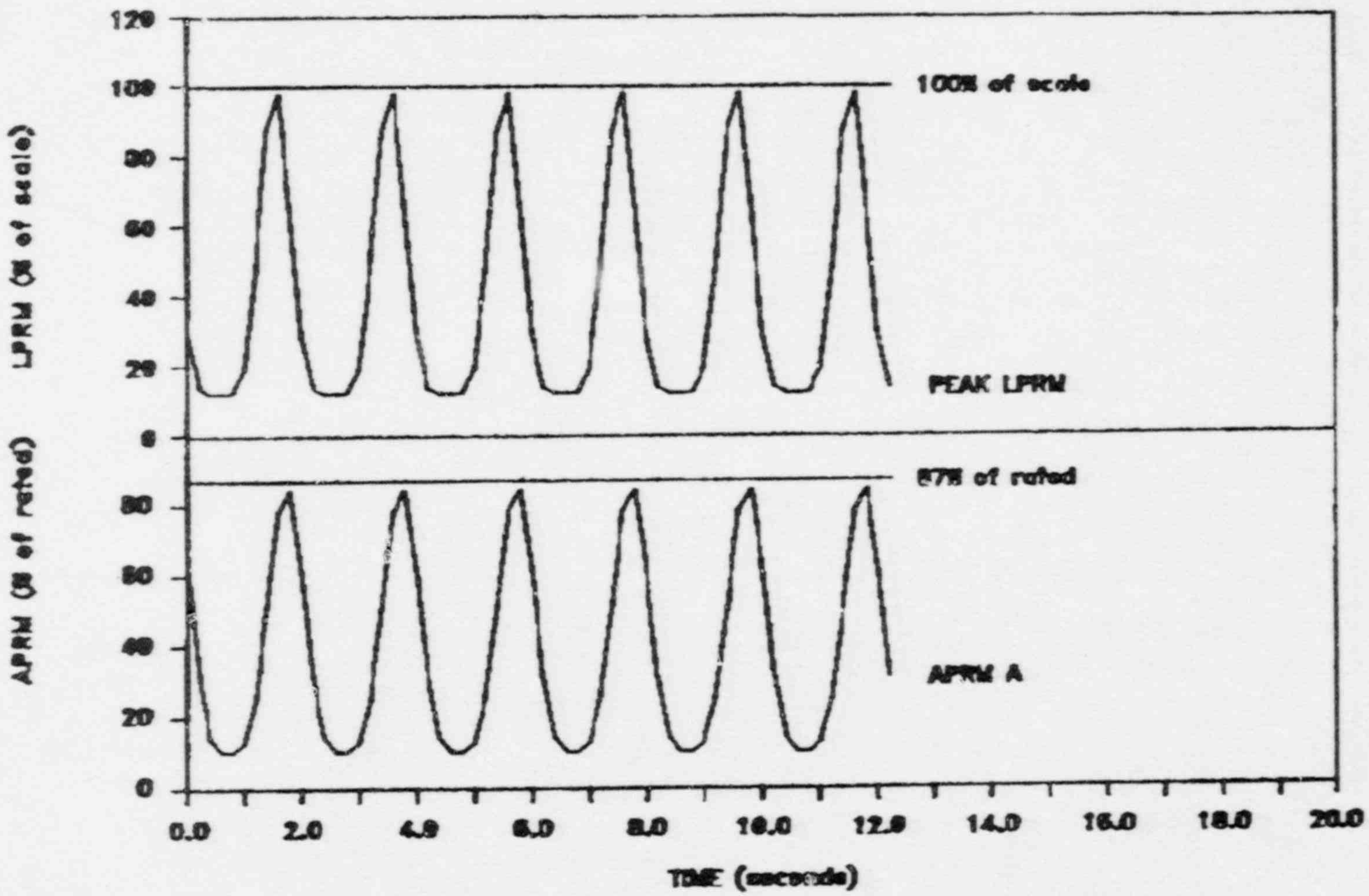


FIGURE 4
LPRM/APRM RESPONSE DURING OSCILLATIONS



NUCLEAR SERVICES DEPARTMENT • SAN JOSE, CALIFORNIA 95125

February 10, 1984
File Tab A

SIL No. 380
Revision 1
Category 1

BWR CORE THERMAL HYDRAULIC STABILITY

The possibility of thermal hydraulic instability in a BWR has been investigated since the startup of early BWRs. These early tests oscillated a control rod within one notch position and measured the response of the core. For modern higher-power density reactors, pressure pertubation techniques were developed to measure the core stability margins. Based on these tests and analytical models, it has been previously identified (Service Information Letter 380) that the high power/low flow corner of the power/flow map (Figure 1) is the region of least stability margin. This region may be encountered during startup/shutdown, during rod sequence exchanges and as a result of a recirculation pump(s) trip event. Service Information Letter 380 discussed the possibility of increased neutron flux noise and recommended appropriate operator action in the event that neutron flux noise of increased magnitude occurs. As the result of new stability test data, additional information on BWR thermal hydraulic stability has been obtained. As such, this revision of SIL-380 is made to reflect the new information and to provide additional operating recommendations in the unlikely event that thermal hydraulic instability induced neutron flux oscillations occur. This SIL-380, Revision 1, replaces SIL-380 issued August 1982 in its entirety and applies to General Electric BWRs using GE BWR fuel.

DISCUSSION

BWR cores typically operate with the presence of global neutron flux noise in a stable mode which is due to random boiling and flow noise. This noise, although exhibiting a dominant frequency of 0.3 to 0.7 Hz (the natural frequency of the BWR), does not result in sustained limit cycle oscillations since the system is in a stable mode. This occurrence of neutron noise is best characterized by the Average Power Range Monitor (APRM) signal which typically shows neutron flux noise levels of 4-9% (peak-to-peak) at rated power/flow conditions with two recirculation pumps in operation. During single recirculation pump operation (SLO), neutron noise levels of 4-12% of rated (peak-to-peak) have been reported for the range of low to high recirculation pump speed.

GENERAL ELECTRIC

Attachment 7

As the power/flow conditions are changed, along with other system parameters (pressure, subcooling, power distribution, etc.) the thermal hydraulic/reactor kinetic feedback mechanism can be enhanced such that random perturbations may result in sustained limit cycle oscillations in power and flow at the dominant frequency of 0.3 to 0.7 Hz. These conditions are most likely to occur at the high power/low flow corner of the power/flow map (Figure 1). Previous stability tests at an operating plant demonstrated the occurrence of limit cycle neutron flux oscillations (as seen by the APRM recordings) at the intersection of the rated rod line and natural circulation flow. These oscillations were readily observed on the APRM recorders and were easily suppressed by the insertion of several control rod notches. In addition, examinations of the individual Local Power Range Monitors (LPRM) indicated that all of the LPRMs were oscillating in phase. Recent stability tests at another plant have also demonstrated the occurrence of limit cycle neutron flux oscillations at natural circulation and several percent above the rated rod line. The oscillations were again observable on the APRMs and suppressed by minimal control rod insertion. It was predicted that limit cycle oscillations would occur at the operating state tested; however, the characteristics of the observed oscillations were different than those previously observed at other stability tests. Examination of the detailed test data of these most recent tests showed that some LPRMs oscillated out of phase with the APRM signal and at higher amplitudes than the core average. Although the local oscillations were larger than the core average, very large margin to safety limits was maintained and the oscillations were detectable and easily suppressed by minimal control rod insertion.

Four hundred twenty reactor years of BWR operating experience (including 150 years of high power density plant operation) have demonstrated that instabilities in BWRs are unlikely at or above natural circulation flow rate and below the rated rod line. In addition since these instabilities are a function of power/flow ratio, they are even less likely to occur in the lower power density designs (BWR/2-3). However, the above tests along with limit cycle oscillations that have been encountered at operating reactors at minimum forced circulation above the rated rod line demonstrate that oscillations may occur at unique operating states.

In summary, as demonstrated by tests and operating experience at BWRs, these oscillations are observable on the neutron monitoring system and can be readily suppressed by control rod insertion (or core flow increase if possible). In addition, the most recent tests indicate that local regions may exhibit characteristics different from those of the core average, therefore the operators should follow the recommendations to observe and mitigate limit cycle oscillations should they occur. Because of their low power density design, these recommendations are for "information only" to BWR2-3 operators.

RECOMMENDATIONS

General Electric recommends that BWR operators using GE BWR fuel monitor the inherent neutron flux signals and avoid or control abnormal neutron flux oscillations (with particular attention to the region of sensitivity in Figure 1 where the probability of sustained neutron flux oscillations increases) as follows:

1. Become familiar and aware of your plants normal average power range monitor (APRM) and local power range monitor (LPRM) peak-to-peak neutron flux for all operating regions of the power/flow map and for all operating modes (e.g., two loop and single loop operation). In particular establish an expected APRM and LPRM peak-to-peak signal for your plant at various operating states and also for special operating modes (i.e., SLO) if these modes will be used. The expected APRM noise amplitude can be easily determined from past steady state strip chart recordings or can be established based on current operating conditions.

2. Whenever making APRM or LPRM readings, verify that the neutron flux noise level is normal. If there is any abnormal increase in the neturon flux response follow the recommendations in Section 6d to suppress the abnormal noise signal.

3. The LPRM gains should be properly calibrated as per current plant procedures. This will permit the LPRM upscale alarm trip setpoints to be set as high as full scale while providing appropriate indication against unacceptable reduction in thermal margin because of power oscillations. The LPRM upscale alarm indicators should be regularly monitored and all upscale alarms should be investigated to determine the cause and to assure that local limits are not being exceeded.

4. Whenever changes are made or happen that cause reactor power to change, monitor the power change on the APRMs and locally on the LPRMs surrounding control rod movement to become familiar with the expected neutron flux signal characteristics.

5. If a recirculation pump(s) trip event results in operation in region 1 of Figure 2:

   a. Immediately reduce power by inserting control rods to or below the 80% rod line using the plant's prescribed control rod shutdown insertion sequence.

b. After inserting control rods, frequently monitor the APRMs and monitor the local regions of the core by using the control rod select switch to display the various LPRM strings which surround the selected control rod. A minimum of nine control rods should be selected to adequately display LPRMs representing each octant of the core and the core center (Figure 3). If there is any abnormal increase in the expected signals, insert additional control rods to suppress the oscillations using the plant's prescribed control rod shutdown insertion sequence.

c. After inserting control rods, monitor the LPRM upscale alarm indicators and verify (using recommendation 5b) that any LPRM upscale alarms which are received are not the result of neutron flux limit cycle oscillations.

d. When restarting recirculation pumps (or switching from low to high frequency speed for flow control valve plants), the operation should be performed below the 80% rod line.

e. Once pumps have been restarted and recovery to power is to commence, follow the recommendations in Section 6.

6. When withdrawing control rods during startup in region 2 of Figure 2:

   a. Monitor the APRMs and the LPRMs surrounding control rod movement continually as power is being increased or flow is being reduced for any abnormal increase in the normal neutron flux response.

   b. Monitor the LPRM upscale alarm indicators and verify (using recommendation 5b) that any LPRM upscale alarms which are received are not the result of neutron flux limit cycle oscillations.

   c. Operate the core in as symmetric a mode as possible to avoid asymmetric power distributions. When possible, control rods should be moved in octant (sequence A) and quadrant mirror (sequence B) symmetric patterns. Control rod movement should be restricted to no more than 2 feet at a time and control rods within a symmetric rod group should be within 2 feet of each other at all times. For BWR/6 plants with ganged rod withdrawal, control rods should be moved in gangs as much as possible to maintain symmetric rod patterns.

d. If there is any abnormal increase in the normally expected neutron flux response, the variations should be suppressed. It is suggested that the operation which caused the increase in neutron flux response be reversed, if practical, to accomplish this suppression; control rod insertion or core flow increase (PCIOMR's should be followed during flow increases) will result in moving toward a region of increased stability.

e. An alternative to recommendation 6a-d is to increase core flow such that operating region 2 of Figure 2 is avoided. PCIOMR guidelines should still be followed.

7. When performing control rod sequence exchanges:

a. Follow recommendations 6a-d, or

b. Perform control rod sequence exchanges outside of regions 1 and 2 of Figure 2.

8. When inserting control rods during shutdown, insert control rods to or below the 80% rod line prior to reducing flow into region 2 of Figure 2 (i.e., avoid region 2 during shutdown).

9. Should any abnormal flux oscillations be encountered, data should be recorded on the highest speed equipment available and all available power, flow, power shape, feedwater, pressure and rod pattern information documented for subsequent evaluation and operational guidance.

Prepared by: G.A. Watford

Aproved by: D L Allred
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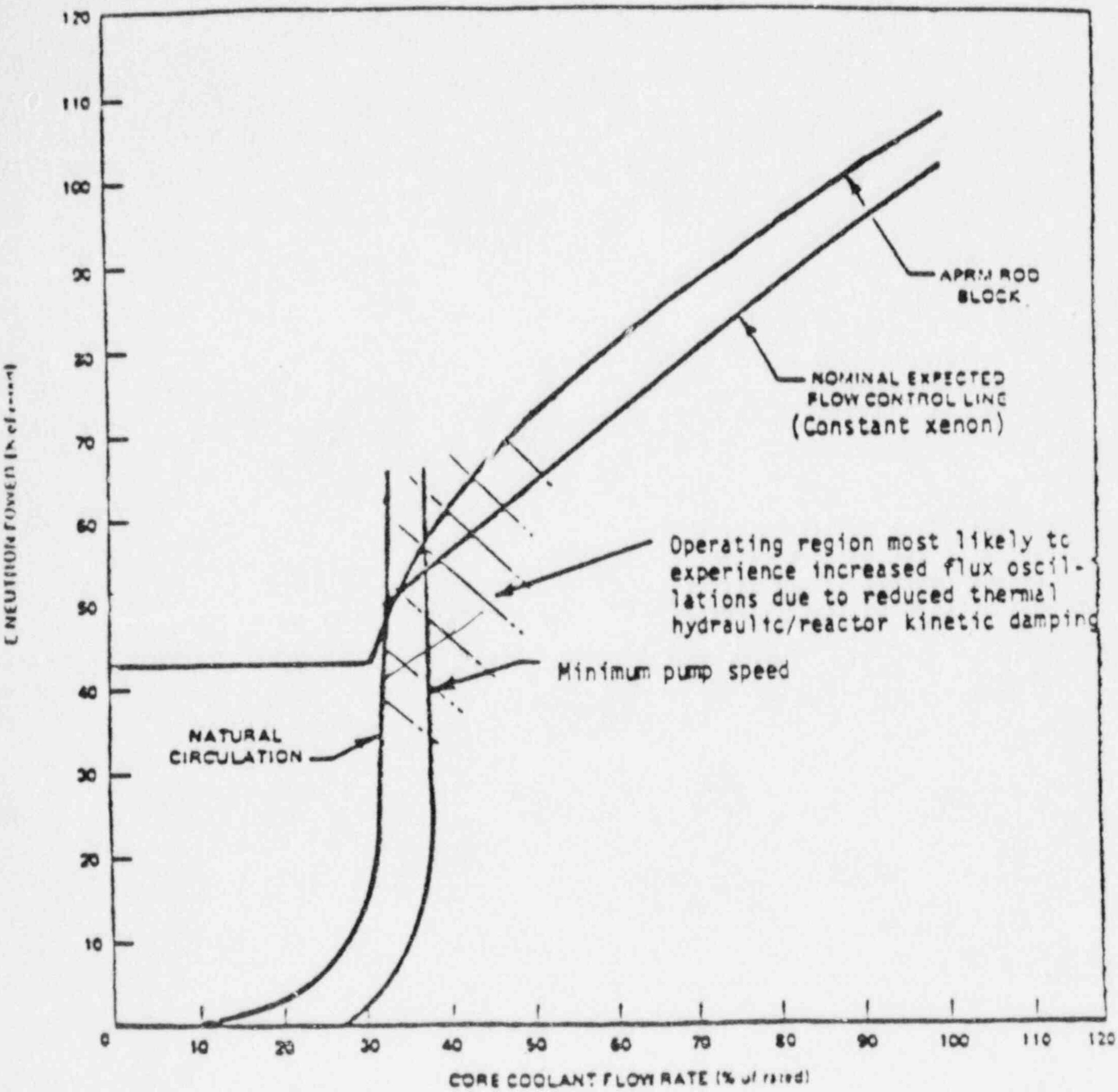
Customer Service Information

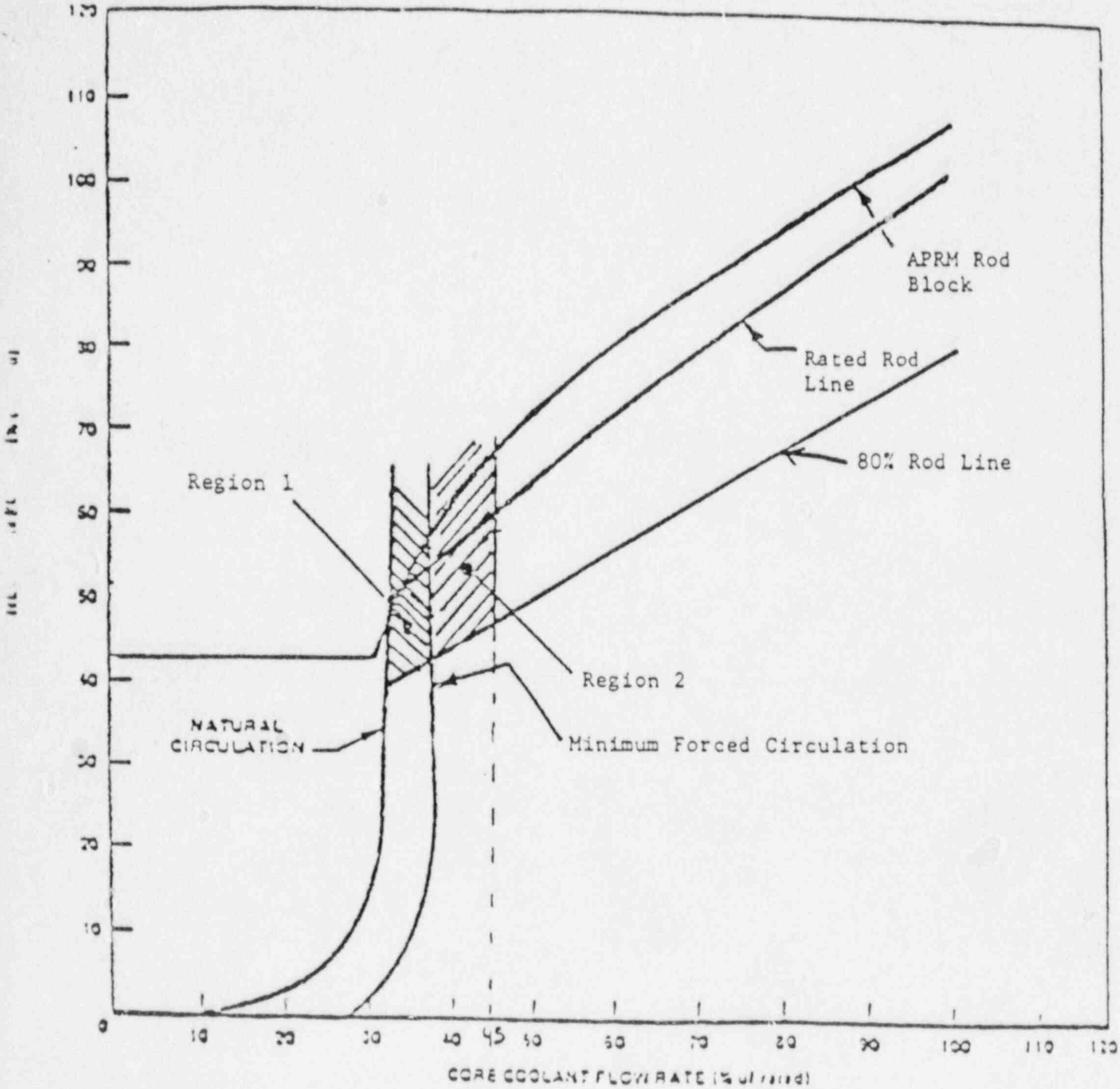
Issued by: R E Bates
R.E. Bates, Specialist
Customer Communications

Product Reference: A71 - Plant Recommendations



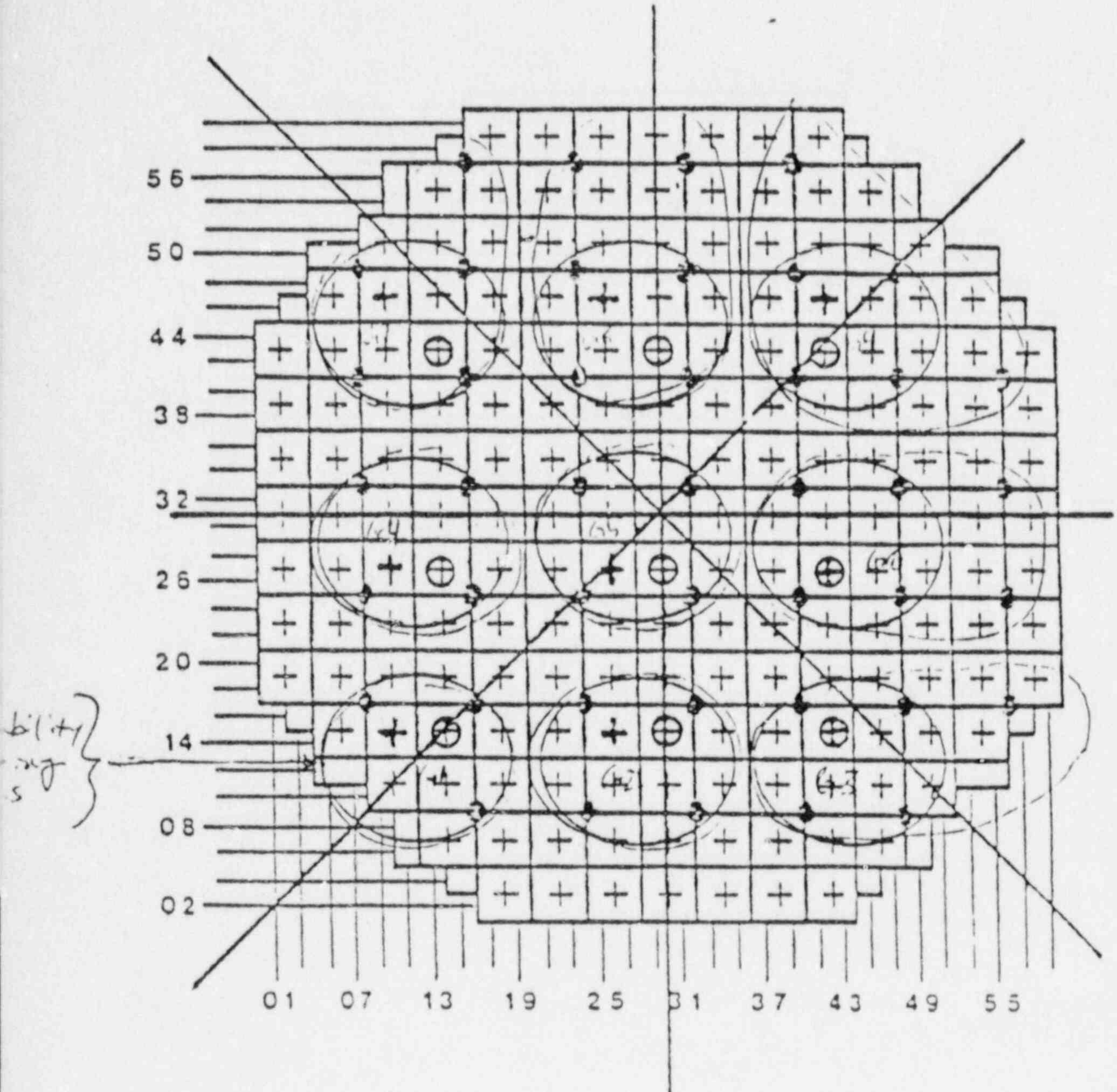
TYPICAL BWR POWER FLOW MAP

FIGURE 1



IDENTIFIED REGIONS OF THE BWR POWER FLOW MAP

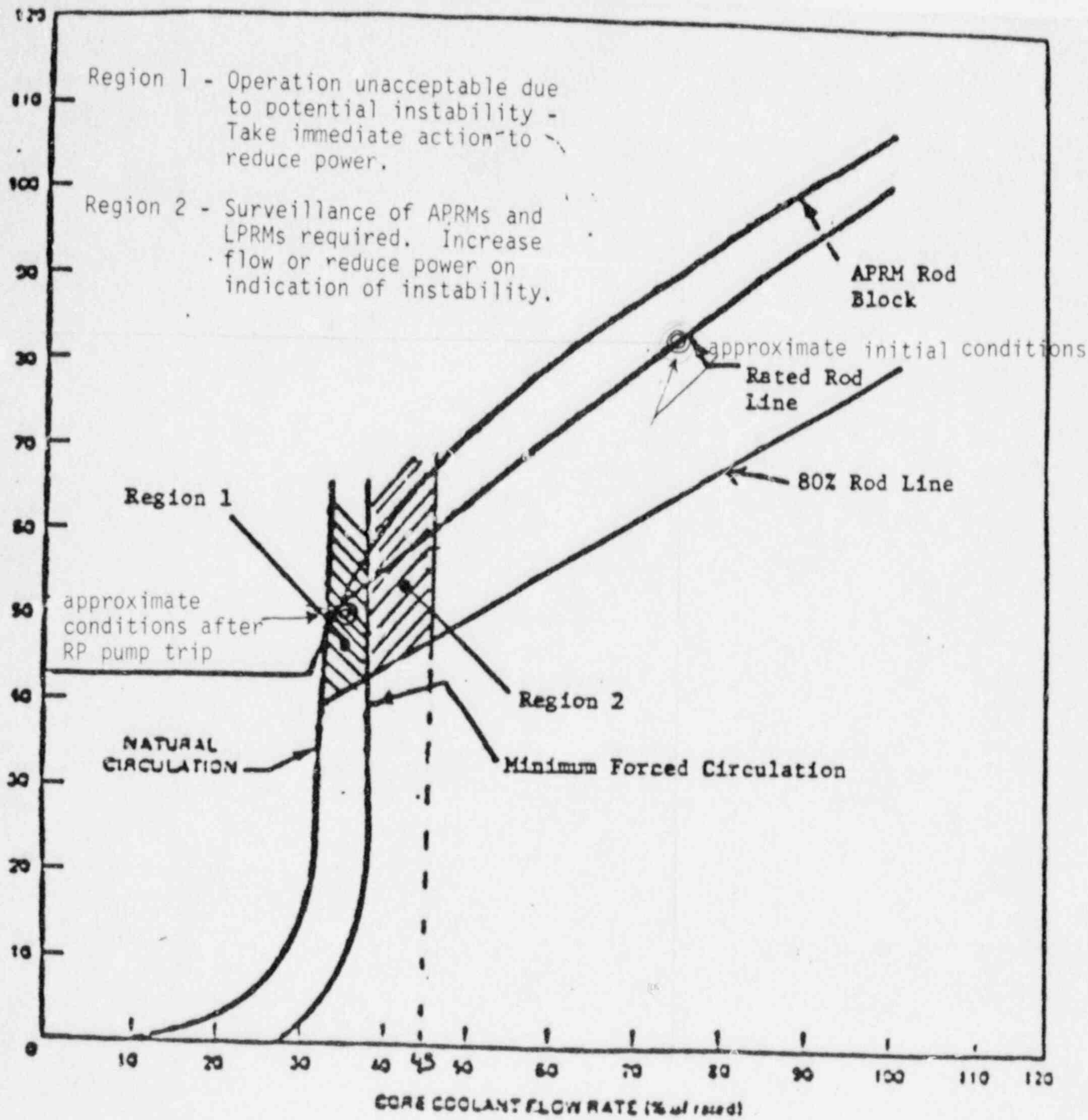
Figure 2



Selected Control Rods ⊕ 14-15 14-27 14-43
30-15 30-27 30-43
42-15 42-27 42-43

TYPICAL LOCAL REGION MONITORING SCHEME

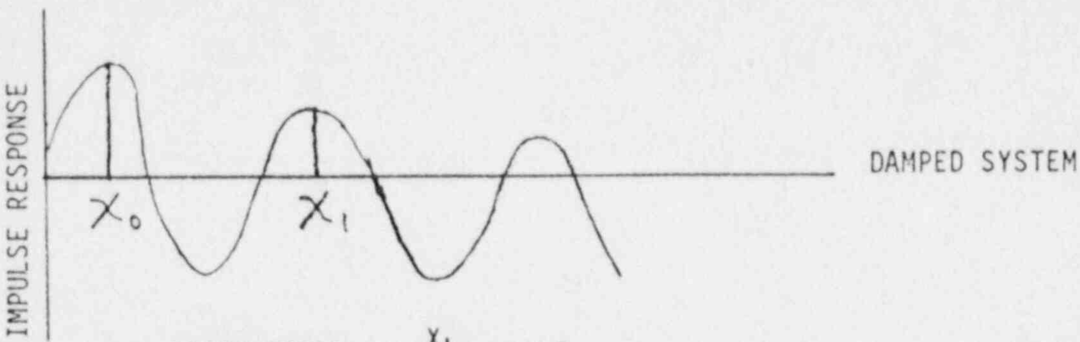
Figure 3



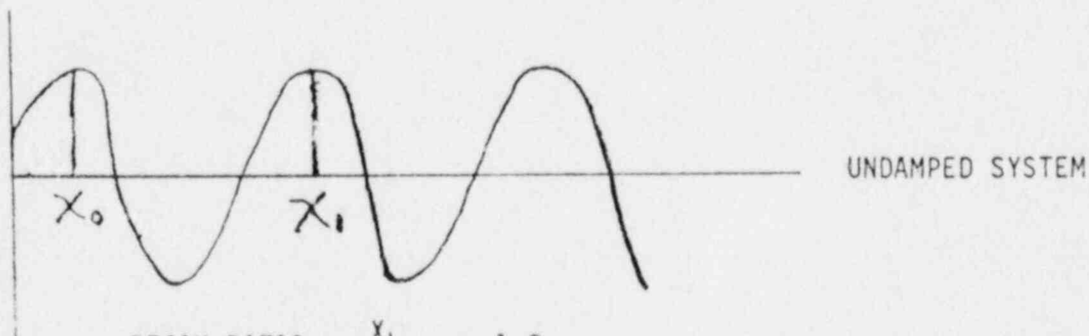
Attachment 3
Figure 1

IDENTIFIED REGIONS OF THE BWR POWER FLOW MAP

MEASURE OF STABILITY IS DECAY RATIO



DECAY RATIO = $\frac{X_1}{X_0} < 1.0$



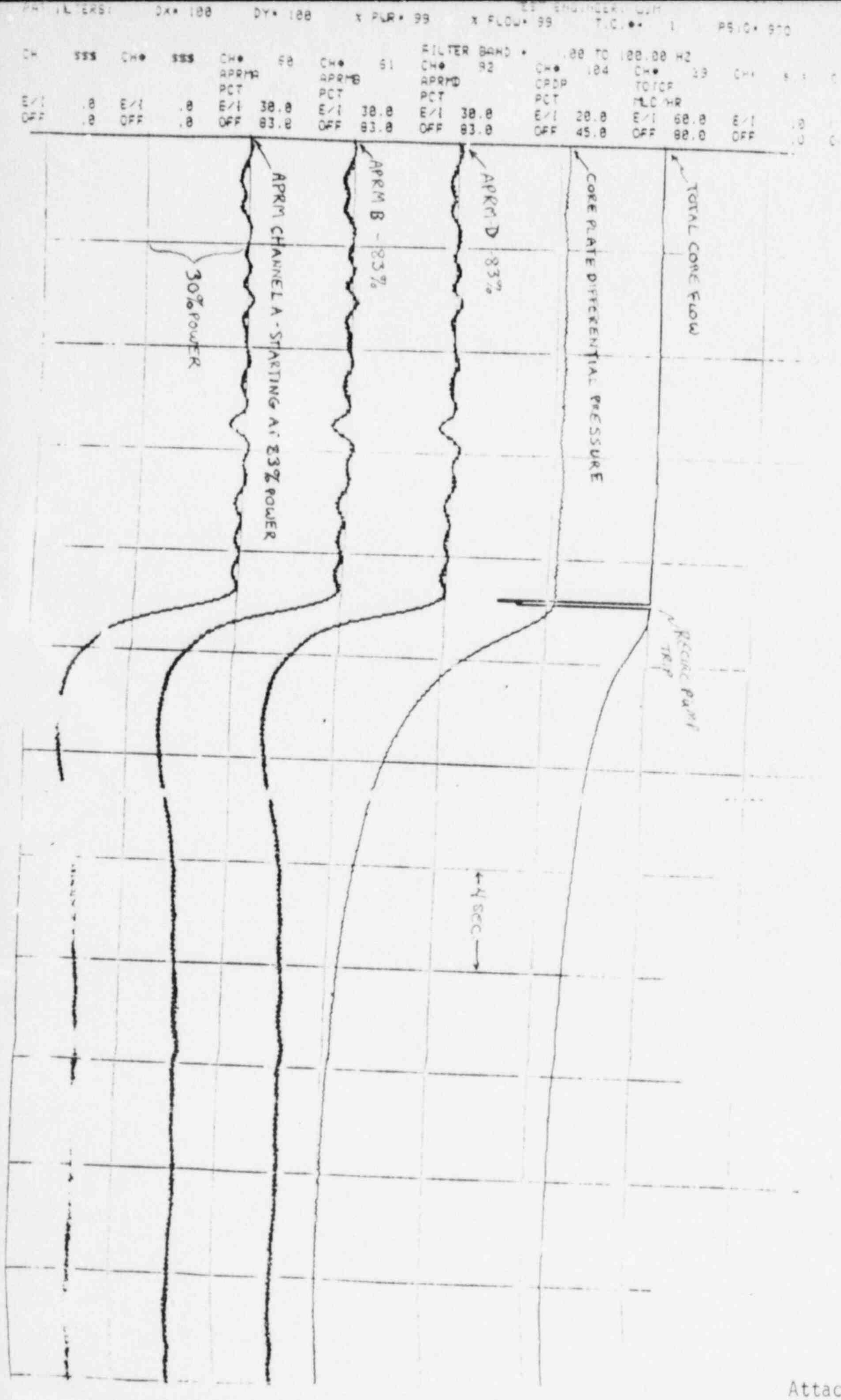
DECAY RATIO = $\frac{X_1}{X_0} = 1.0$

LIMIT CYCLE

FOR BWRs, DECAY RATIO IS A FUNCTION OF

FUEL DESIGN
CORE OPERATING CONDITIONS
FUEL BURNUP

Attachment 3
Figure 2

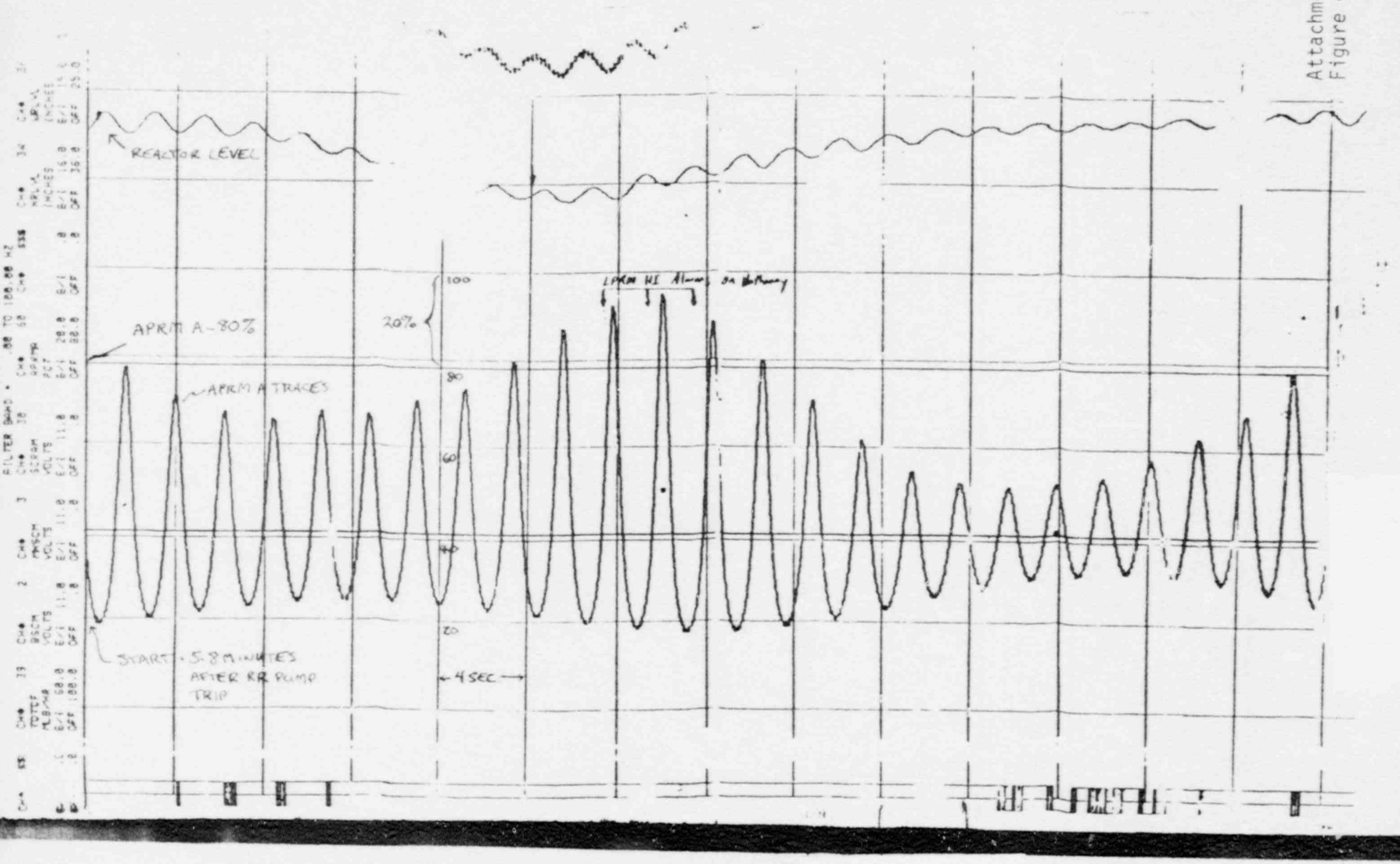


Startrec Traces - Beginning of Event

Attachment 3
Figure 3

Attachment 3
Figure 4

Startrec Traces - Oscillations



3/4.4 REACTOR COOLANT SYSTEM

3/4.4.1 RECIRCULATION SYSTEM

RECIRCULATION LOOPS

LIMITING CONDITION FOR OPERATION

3.4.1.1 Two reactor coolant system recirculation loops shall be in operation.

APPLICABILITY: OPERATIONAL CONDITIONS 1* and 2*.

ACTION:

a. With one reactor coolant system recirculation loop not in operation:

   1. Within 4 hours:

      a) Place the recirculation flow control system in the Master Manual mode, and

      b) Increase the MINIMUM CRITICAL POWER RATIO (MCPR) Safety Limit by 0.01 to 1.08 per Specification 2.1.2, and,

      c) Increase the MINIMUM CRITICAL POWER RATIO (MCPR) Limiting Condition for Operation by 0.01 per Specification 3.2.3, and,

      d) Reduce the MAXIMUM AVERAGE PLANAR LINEAR HEAT GENERATION RATE (MAPLHGR) limit to a value of 0.85 times the two recirculation loop operation limit per Specification 3.2.1, and,

      e) Reduce the Average Power Range Monitor (APRM) Scram and Rod Block and Rod Block Monitor Trip Setpoints and Allowable Values to those applicable for single loop recirculation loop operation per Specifications 2.2.1, 3.2.2, and 3.3.6.

   2. When operating within the surveillance region specified in Figure 3.4.1.1-1:

      a) With core flow less than 39% of rated core flow, initiate action within 15 minutes to either:

         1) Leave the surveillance region within 4 hours, or

         2) Increase core flow to greater than or equal to 39% of rated flow within 4 hours.

      b) With the APRM and LPRM# neutron flux noise level greater than three (3) times their established baseline noise levels:

---

*See Special Test Exception 3.10.4.

#Detector levels A and C of one LPRM string per core octant plus detector levels A and C of one LPRM string in the center region of the core should be monitored.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

1) Initiate corrective action within 15 minutes to restore the noise levels to within the required limit within 2 hours, otherwise

2) Leave the surveillance region specified in Figure 3.4.1.1-1 within the next 2 hours.

3. The provisions of Specification 3.0.4 are not applicable.

4. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

b. With no reactor coolant system recirculation loops in operation, immediately initiate measures to place the unit in at least HOT SHUTDOWN within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.1.1 Each reactor coolant system recirculation loop flow control valve shall be demonstrated OPERABLE at least once per 18 months by:

a. Verifying that the control valve fails "as is" on loss of hydraulic pressure at the hydraulic power unit, and

b. Verifying that the average rate of control valve movement is:

1. Less than or equal to 11% of stroke per second opening, and

2. Less than or equal to 11% of stroke per second closing.

4.4.1.2 With one reactor coolant system recirculation loop not in operation:

a. Establish baseline APRM and LPRM# neutron flux noise level values within 4 hours upon entering the surveillance region of Figure 3.4.1.1-1 provided that the baseline values have not been established since last refueling.

b. When operating in the surveillance region of Figure 3.4.1.1-1, verify that the APRM and LPRM# neutron flux noise levels are less than or equal to three (3) times the baseline values:

1. At least once per 12 hours, and

2. Within 1 hour after completion of a THERMAL POWER increase of at least 5% of RATED THERMAL POWER, initiating the surveillance within 15 minutes of completion of the increase.

c. When operating in the surveillance region of Figure 3.4.1.1-1, verify that core flow is greater than or equal to 39% of rated core flow at least once per 12 hours.

#Detector levels A and C of one LPRM string per core octant plus detector levels A and C of one LPRM string in the center region of the core should be monitored.

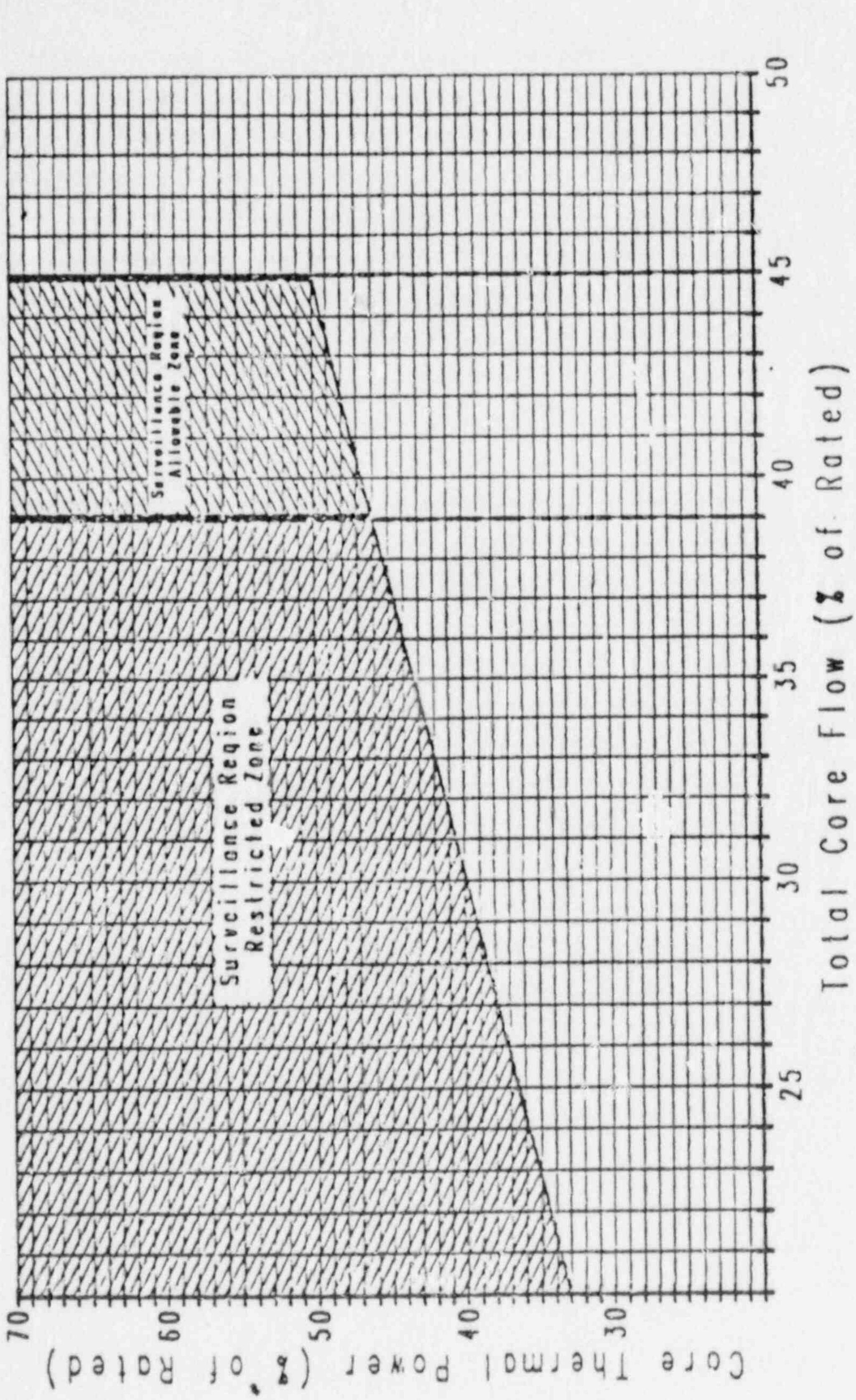


Figure 3.4.1.1-1

CORE THERMAL POWER (% OF RATED) VERSUS
TOTAL CORE FLOW (% OF RATED)

Commonwealth Edison
LaSalle County Nuclear Station
Rural Route #1, Box 220
Marseilles, Illinois 61341
Telephone 815/357-6761

April 7, 1988

U. S. Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555

Dear Sir:

Licensee Event Report #88-003-00, Docket #050-374 is being submitted to your office in accordance with 10CFR50.73(a)(2)(iv).

WRoAmft
G. J. Diederich
for Station Manager
LaSalle County Station

GJD/MHR/kg

Enclosure

xc: Nuclear Licensing Administrator
NRC Resident Inspector
NRC Region III Administrator
INPO - Records Center

8804140127 6PP

Attachment 6
APR 12 1988

LICENSEE EVENT REPORT (LER)

Facility Name (1)	Docket Number (2)	Page (3)
LaSalle County Station Unit 2	0 5 0 0 0 3 7 4	1 of 0 5

Title (4) Reactor Scram on High Average Power Range Monitor Flux Level due to the Personnel Valving Error

Event Date (5)			LER Number (6)			Report Date (7)			Other Facilities Involved (8)	
Month	Day	Year	Year	Sequential Number	Revision Number	Month	Day	Year	Facility Names	Docket Number(s)
0 3	0 9	8 8	8 8	0 0 3	0 0	0 4	0 7	8 8		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 0 8 4

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10CFR (Check one or more of the following) (11)

__	20.402(b)	__	20.405(c)	X	50.73(a)(2)(iv)	__	73.71(b)
__	20.405(a)(1)(i)	__	50.36(c)(1)	__	50.73(a)(2)(v)	__	73.71(c)
__	20.405(a)(1)(ii)	__	50.36(c)(2)	__	50.73(a)(2)(vii)	__	Other (Specify in Abstract below and in Text)
__	20.405(a)(1)(iii)	__	50.73(a)(2)(i)	__	50.73(a)(2)(viii)(A)		
__	20.405(a)(1)(iv)	__	50.73(a)(2)(ii)	__	50.73(a)(2)(viii)(B)		
__	20.405(a)(1)(v)	__	50.73(a)(2)(iii)	__	50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

Name	TELEPHONE NUMBER
	AREA CODE
Milton H. Richter, Asst. Technical Staff Supervisor, ext. 259	8 1 5 3 5 7 - 6 7 6 1

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
A	B N			N					
D				N					

SUPPLEMENTAL REPORT EXPECTED (14)		Expected Submission Date (15)	Month	Day	Year
__ Yes (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

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

At 1732 hours on March 9, 1988, with Unit 2 in Operational Condition 1 (Run) at approximately 84% power, a valving error during an instrument surveillance caused the Reactor Recirculation (RR) pumps to trip off. This caused a large and rapid power reduction to approximately 40% power. While trying to stabilize the feedwater heaters and restart a RR pump, the Average Power Range Monitors (APRMs) were observed to be oscillating between 25-50% power (25% peak-to-peak). As preparations were being made to manually scram the reactor, an automatic scram occurred on APRM neutron flux high (118% trip) at 1739 hours. The scram was caused by neutron flux oscillations experienced while the unit was at a high rod line and low flow (natural circulation) condition.

The root cause of this event was personnel error for the initial transient, and procedural inadequacy for the scram. Although operating personnel were cognizant of the potential for (and observed) neutron flux oscillations, the operating procedures did not provide sufficient guidance for prevention/suppression of oscillations. The neutron flux oscillations seen by the APRMs and Local Power Range Monitors were occurring "in phase" across the core and were bounded by the APRM high neutron flux scram (118%).

Operating procedures were revised to ensure prompt action (as recommended by General Electric SIL 380, Rev. 1) when the unit is operating at a condition which is susceptible to neutron flux oscillations. In addition, as a temporary measure, a Confirmatory Action Letter issued by NRC Region III requires the plant to be scrammed (manual) immediately in the event of a dual pump (RR) trip.

This event is reportable pursuant to the requirements of 10CFR50.73(a)(2)(iv) due to the automatic actuation of the Reactor Protection System.

PLANT AND SYSTEM IDENTIFICATION

General Electric - Boiling Water Reactor

Energy Industry Identification System (EIIS) codes are identified in the text as [XX].

A. CONDITION PRIOR TO EVENT

Unit(s): 2 Event Date: 3/9/88 Event Time: 1739 hours

Reactor Mode(s): 1 Mode(s) Name: Run Power Level(s): 84%

B. DESCRIPTION OF EVENT

At 1739 hours on March 9, 1988, Unit 2 scrammed (automatic) on neutron flux high (118% trip) from the Average Power Range Monitors (APRMs, NR) [IG] due to neutron flux oscillations. The neutron flux oscillations occurred while the unit was at a low flow (natural circulation) and high rod line condition following the trip of the Reactor Recirculation (RR) [AD] pumps.

At 1732 hours, with Unit 2 in Operational Condition 1 (Run) at approximately 84% power (930 MWe), the Instrument Maintenance (IM) Department was performing a surveillance (functional test) on Differential Pressure Switch DPS-2B21-N037BB. This switch supplies a Reactor Core Isolation Cooling (RCIC, RI) [BN] initiation at reactor vessel level 2 (-50 inches). At this time, the "A" Turbine Driven Reactor Feedwater Pump and Motor Driven Reactor Feedwater Pump were operating in three-element control, and feedwater level control (FW) [JK] was selected to channel "B" (which utilizes the same instrument reference leg as DPS-2B21-N037BB). In addition, there were two (2) Nuclear Station Operators (NSO's, licensed RO's) in the Unit 2 control room at this time.

Locally at DPS-2B21-N037BB, the IM technician had successfully isolated the switch (the variable and reference leg isolation valves were closed and the equalizing valve was open) in accordance with the surveillance procedure. While attempting to vent the switch prior to installation of the test equipment, the technician inadvertently opened the variable and reference leg isolation valves instead of the vent/test valves. This initiated a "pressure equalization" between the variable and reference legs, and resulted in a high "indicated" reactor water level to feedwater level control. The high "indicated" level to feedwater level control caused the feedwater pumps to begin slowly reducing flow. In addition, a high reactor water level alarm (level 7, +40.5 inches) was received in the control room which prompted one NSO to monitor feedwater level control.

A second IM technician, who was observing the surveillance locally, notified the primary technician of the valving error, and the variable and reference leg isolation valves were immediately closed (the valving error existed for approximately 15 seconds). The isolation of the reference leg from the variable leg resulted in a low "indicated" level spike. From level switches which utilize the same reference leg as DPS-2B21-N037BB, the level spike caused the following to occur;

B. DESCRIPTION OF EVENT (CONTINUED)

- both RR pumps received an ATWS level 2 signal, causing the RR pumps to trip off (per design), and
- channel B-1 of the Reactor Protection System (RPS, RP) [JC] received a level 3 (+12.5 inches) signal for low reactor water level, causing a half scram condition.

The half scram signal was reset upon verification that "actual" reactor water level was not low.

Due to the large and rapid power reduction (following the trip of the RR pumps the unit was at approximately 40% power), feedwater heater high level alarms were received and heaters began isolating (steam side). While one NSO monitored feedwater level control, which was adequately handling the transient ("B" level control channel had stabilized following the initial spike caused by the closure of the isolation valves), the attention of the second NSO was on re-establishing heaters (by opening the extraction steam valves) and preparing for the restart of the RR pumps (as directed by the operating procedure for loss of recirculation flow).

Approximately 5 minutes into the event, Local Power Range Monitor (LPRM, NR) [IG] downscale alarms began annunciating and the APRMs were observed to be oscillating between 25% and 50% power (25% peak-to-peak) with an approximate 2 second period. Cognizant of the unit's location on the power-to-flow map (region susceptible to neutron flux oscillations), operating personnel were attempting to start one RR pump to re-establish recirculation flow and restore stability. If the pump start attempt was unsuccessful, an manual scram of the reactor was planned. After positioning the "A" RR flow control valve for pump restart, two unsuccessful start attempts were made on the "A" RR pump. As shift personnel were preparing to manually scram the unit, an automatic scram occurred on APRM neutron flux high (118% trip) at 1739 hours.

This event is reportable pursuant to the requirements of 10CFR50.73(a)(2)(iv) due to the automatic actuation of the Reactor Protection System.

C. APPARENT CAUSE OF EVENT

The root cause of this event was personnel error for the initial transient, and procedural inadequacy for the scram.

The initiating transient (trip of the RR pumps) was caused by a valving error (by an IM technician) during the surveillance on DPS-2B21-N037BB. The low "indicated" level spike which occurred during correction of the valving error resulted in tripping the RR pumps and placing the unit in a natural circulation condition.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) Year	Sequential Number	Revision Number	Page (3)
LaSalle County Station Unit 2	0 5 0 0 0 3 7 4	8 8	- 0 0 3	- 0 0	0 4 OF 0 5

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [xx]

C. APPARENT CAUSE OF EVENT (CONTINUED)

The scram was caused by neutron flux oscillations experienced while the unit was at a high rod line (high power) and low flow (natural circulation) condition. This condition (high rod line and low flow) has previously been identified by General Electric to be susceptible to neutron flux oscillations (core thermal hydraulic instabilities). The operating procedure for loss of recirculation flow (two pump trip) did not include the insertion of control rods (power rods) as an immediate corrective action. The insertion of power rods would have reduced rod line which is a recommended corrective action to prevent/suppress neutron flux oscillations. Operating personnel response for this event was found to be consistent with station procedures. The operating personnel were cognizant of the potential for (and observed)(neutron flux oscillations, however, the operating procedures for this event did not provide sufficient guidance for prevention/suppression of oscillations.

The exact cause for the inability to start the "A" RR pump could not be determined, however, it is believed that a pump start permissive was not satisfied. The RR pump start circuitry contains numerous interlocks/permissives which need to be satisfied to achieve a successful pump start. Following the scram, the suspect permissive was no longer required for pump start, and a successful pump start occurred. At this time, the control room operator has no indication which verifies that the RR pump start permissives are satisfied.

D. SAFETY ANALYSIS OF EVENT

A review of this event determined that the neutron flux oscillations, seen by the APRM's and LPRM's, were occurring "in phase" across the core and were bounded by the APRM high neutron flux scram (118%) which automatically terminated the event. The frequency and magnitude of the oscillations experienced were consistent with the characteristics observed during stability testing and operation at other Boiling Water Reactors (BWR's). Previous analyses have demonstrated that the oscillations in neutron flux observed during this event do not result in exceeding fuel thermal and mechanical safety and design limits. Therefore, the neutron flux oscillations in this event did not adversely affect any safety system or the safe operation of the plant.

E. CORRECTIVE ACTIONS

This event was reviewed with General Electric and Commonwealth Edison's Nuclear Fuel Services Department.

The IM personnel involved in this event have been counseled.

This event has been reviewed with all IM Department personnel.

Operating Department personnel have reviewed this event through shift briefings.

E. CORRECTIVE ACTIONS (CONTINUED)

Operating procedures have been reviewed and revised to ensure prompt and proper action when the unit is operating at a condition which is susceptible to neutron flux oscillations. The procedure revisions incorporated the recommendations provided by General Electric in Service Information Letter (SIL) 380, Revision 1 (BWR Core Thermal Hydraulic Stability), with particular emphasis on the immediate insertion of control (power) rods upon the loss of a RR pump(s) at greater than the 80% flow control line.

In accordance with a Confirmatory Action Letter issued by the Nuclear Regulatory Commission (Region III), the unit will be manually scrammed upon the loss of both RR pumps. This is a temporary measure and is being controlled by an Operating Department special order (88-21).

During the startup of the unit, chemistry sampling (reactor water and off gas) occurred at an increased frequency to verify the integrity of the fuel. No indication of any fuel problems were found from this sampling.

Since the onset of neutron flux oscillations occurred in approximately five (5) minutes during this event, amendments to the station's Technical Specifications are being submitted which will re[illegible]re prompt initiation of corrective action when the unit is operating at a condition which is susceptible to neutron flux oscillations. Action Item Record (AIR) 374-200-88-01801 will track this item.

A discussion on this event, and the Operating procedure revisions which resulted from this event, will be presented to all licensed Operating personnel at the next scheduled Operator training session. AIR 374-200-88-01802 will track completion of this item.

A modification is being considered which would install a pump permissive indicating light for each RR pump. The light will provide indication for prompt assessment of the status of the pump permissives. AIR 374-200-88-01803 will track the completion of this item.

At this time, Commonwealth Edison's Production Training Department is investigating the ability to remodel the LaSalle simulator for this type of an event to enhance operator training. AIR 374-200-88-01804 will track this item.

F. PREVIOUS EVENTS

None.

G. COMPONENT FAILURE DATA

None.