CALVERT CLIFFS NUCLEAR POWER PLANT

LOSS OF COOLANT ACCIDENT

EOP-5

TECHNICAL BASIS DOCUMENT

REVISION 23

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The primary basis reference for the development of the Calvert Cliffs Nuclear Power Plant's Emergency Operating Procedures (EOPs) is CEN-152, Emergency Procedure Guidelines (EPGs). These guidelines provide technical guidance for the production of the EOPs.

NUREG-0899 defines technical guidelines as:

> Documents that identify the equipment or systems to be operated and list the steps necessary to mitigate the consequences of transients and accidents and restore safety functions. Technical guidelines represent the translation of engineering data derived from transient and accident analyses into information presented in such a way that it can be used to write EOPs. There are two types of technical guidelines, as defined below. Generic technical guidelines are guidelines prepared for a group of plants with a similar design. Plant-specific technical guidelines are one of the following : a. Technical guidelines prepared by plants not using generic technical guidelines, or b. Where a plant is using generic technical guidelines, a description of the planned method for developing plant-specific EOPs from the generic guidelines including plant-specific information (e.g., deviations from generic technical guidelines when necessary because of different plant equipment, operating characteristics, or design).

This Technical Basis Document is part of the equivalent plant-specific technical guideline as defined in NUREG-0899. As such, in addition to providing the technical basis for the procedure, justification is provided for deviations from the EPGs.

Where EOP steps are equivalent to EPG steps, no additional information is provided. Where a deviation exists, a statement explaining the deviation is provided. If justification for the deviation differs from the step basis, separate justification is also provided.

The EPG event mitigation strategies have been developed around the concept of safety functions. The concept of safety functions introduces a systematic approach to plant operations based on a hierarchy of protective actions. The protective actions are directed at mitigating the consequences of an event and, once fulfilled, ensure proper control of the event in progress. A safety function is defined as a condition or action that prevents core damage or minimizes radiation release to the public. A complete set of safety functions needs to be fulfilled to ensure proper operator control of the event and public safety. Per the EPG, the application of the safety function concept in a restructured format is acceptable as long as the format contains actions and acceptance criteria necessary to control, and fulfill, the individual safety functions, and the safety function hierarchy is preserved. Throughout the EOPs, CCNPP has combined the RCS Inventory Control and RCS Pressure Control safety function into the RCS Pressure and Inventory Control safety function, and the Core Heat Removal and RCS Heat Removal safety function into the Core and RCS Heat Removal safety function (as does the EPG in the Functional Recovery Guideline). The EOPs also combine, the Containment Isolation, Containment Temperature and Pressure Control and Containment Combustible Gas Control safety functions into the Containment Environment safety function and the Radiation Levels External to Containment safety function.

REFERENCES

1. CEN-152, Emergency Procedure Guidelines.

2. EOP-5, Excess Steam Demand Event Technical Basis Document, Rev. 13.

3. Calvert Cliffs Nuclear Power Plant Units 1 and 2 Updated Final Safety Analysis Report.

4. Calvert Cliffs Nuclear Power Plant Units 1 and 2 Technical Specifications, Appendix "A" To license Nos. DPR-53 and DPR-69.

5. Action Value Basis Documents:

EOP-01.03	EOP-04.02	EOP-04.03
EOP-04.04	EOP-04.05	EOP-06.01
EOP-06.03	EOP-08.01	EOP-09.01
EOP-09.02	EOP-12.01	EOP-12.02
EOP-12.03	EOP-12.04	EOP-12.05
EOP-13.01	EOP-13.02	EOP-14.01
EOP-14.02	EOP-14.03	EOP-18.01
EOP-18.02	EOP-19.01	EOP-19.02
EOP-19.04	EOP-19.06	EOP-19.07
EOP-19.09	EOP-19.10	EOP-19.13
EOP-22.05	EOP-22.10	EOP-22.11
EOP-22.13	EOP-22.14	EOP-22.16
EOP-22.17	EOP-22.18	EOP-22.19
EOP-22.20	EOP-22.24	EOP-22.26
EOP-22.27	EOP-22.28	EOP-23.01
EOP-23.03	EOP-24.01	EOP-24.02
EOP-24.03	EOP-24.04	EOP-24.05
EOP-24.08	EOP-24.12	EOP-24.14
EOP-24.19	EOP-24.21	EOP-24.22
EOP-24.24	EOP-24.30	EOP-24.33
EOP-24.36	EOP-27.03	EOP-27.10
EOP-27.12	EOP-29.01	EOP-31.01
EOP-33.01	EOP-34.01	EOP-35.02
EOP-35.04	EOP-36.02	EOP-36.05
EOP-42.01	EOP-43.01	EOP-45.01
EOP-47.01	EOP-54.01	EOP-54.02
EOP-56.01	EOP-59.01	EOP-59.02
EOP-59.03	EOP-68.01	EOP-78.01
EOP-79.01	EOP-80.01	EOP-85.01

6. I.M. Sommerville, BGE Nuclear Engineering Unit, NEU 94-161, memo to W.J. Lippold, dated May 26, 1994.

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REFERENCES (continued)

7. SOER 97-01, Potential Loss of High Pressure Injection and Charging Capability From Gas Intrusion.

8. Ian Sommerville, BG&E Nuclear Engineering Unit, NEU 92-445, memo to C.J. Andrews, dated December 30, 1992.

9. S.M. Mirsky, Principal Engineer - Analytical Support Unit, memo to J.F. Lohr dated November 13, 1986.

10. G.C. Creel, BG&E Vice President Nuclear Energy, letter to the NRC dated December 17, 1990.

11. SOER 93-01, Diagnosis and Mitigation of Reactor Coolant System Leakage including Steam Generator Tube Ruptures.

12. TSES Information Request Documentation Form TSES-2-0000222.

13. Ian Sommerville, BGE Nuclear Engineering Unit, NEU 99-109, memo to R.K. Bleacher dated April 21, 1999.

14. Ian Sommerville, BGE Nuclear Engineering Unit, NEU 00-083, memo to R.K. Bleacher dated April 7, 2000.

15. SOER 82-07, Reactor Vessel Pressurized Thermal Shock.

16. D.L. Shaw, BG&E Licensing, letter to NRC dated March 28, 1989.

17. Sam Moore, BG&E E&C Systems Engineering Unit, memo to John Wilson dated April 3, 1991.

18. K.B. Cellars, BGE Design Engineering, ME940513.012, letter to J.E. Stanley, dated March 11, 1994.

19. Ian Sommerville, BG&E Nuclear Engineering Unit, NEU 93-035, memo to R.K. Bleacher, PD&MAU, dated February 5, 1993.

20. P.S. Furio, BG&E Licensing Unit, letter to K.B. Umphrey dated February 15, 1989.

21. Commitment Resolution Document AIT 1F9400897 dated November 14, 1994.

22. Ian Sommerville, BGE Nuclear Engineering Unit, NEU 93-176, to W.J. Lippold, dated June 30, 1993.

23. Ian Sommerville, BGE Nuclear Engineering Unit, NEU 94-021, to W.J. Lippold, dated July 28, 1994.

(continue)

REFERENCES (continued)

24. TELCOM between C. Drumgoole, PD&MAU, R.A. Gambill, PMU, and Don Spencer of Sulzer-Bingham on July 6, 1990.

25. D.L. Glady BGE Electrical Engineering memo to E.D. Hemmila dated September 26, 1994.

26. J.F. Williams, BG&E Nuclear Engineering Unit, Letter to POSRC, NEU 90-271, dated April 9, 1990.

27. M.T. Finley, BG&E Nuclear Engineering Unit, NEU 94-155, memo to C.J. Andrews, PD&MAU, dated May 20, 1994.

28. M.T. Finley, BG&E Nuclear Engineering Unit, memo to R.J. Deatly, NEU 92-214, dated June 1, 1992.

29. A.S. Drake memo to D.E.Lenker ME920237.052 dated Feb.27, 1992.

30. Rich Buttner to Robert K Bleacher, DMLS DE04344, dated May 11, 1998.

31. Ian Sommerville, BGE Nuclear Engineering Unit, NEU 94-239, memo to C.R. Stancil dated August 26, 1994.

32. SOER 94-01, Non-conservative Decisions and Equipment Performance Problems Result in a Reactor Scram, Two Safety Injections and Water-Solid Conditions.

33. CA04978

34. Time Delay To Bring Failed SRW Pump Train Back In Service, CA06052

35. M.T. Finley, Fuel Operating Services Unit, DE05679, Memo to S.C. McCord, dated March 31,2003.

EOP-5 LOSS OF COOLANT ACCIDENT
EPG/EOP CROSS REFERENCE

EPG Step No.	EOP Step No.
Purpose	I.
Entry Conditions	II.
Exit Conditions	IV.A.1.1/AH.1/4
1/1.1	IV.A.1/1.1
2	IV.B
3	IV.C
4	IV.D.1/2
5	IV.D.3
6.a	IV.E.1
6.b/7/7.1	IV.E.3
8	IV.F.1/2/4/7
9	IV.F.8
10/11/12	IV.G
12A/12A.1/12B	IV.W
13	IV.I.3
14/47	IV.F.9
15	IV.I.5
16/62	IV.J.1
17/63	IV.D.2.d/e/I.1/2
18/19/20/21/48/49/50/51	IV.K
21A/37B	IV.X
22	IV.AA
23/55	IV.J.3
24/24.1/24.2/56/56.1/56.2	IV.J.1/2
25/26/57	IV.L
27/27.1/64/64.1	IV.M
28/65	IV.T
29/29.1/66/66.1	IV.N.2
30	IV.N.2.1
31/32	IV.AC
33	IV.O
34/34.1/34.2/34.3/34.4	IV.P
35/37/37.1	IV.S
36	N/A
37A/37A.1	IV.S.1.f/g
37C	IV.S.1.h
38/39	IV.AD
40	IV.AE
41	IV.G.9
42	IV.W.1

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44	IV.W/Y/Z/AH.2
45/72	IV.AG.1
46	IV.AE.2
52	IV.AA
53/53.1	IV.J.2
54	IV.AB
58/59	IV.F.9/10
60	IV.H
61	IV.I.4
67/68	IV.AC
69/70	IV.AD
71	IV.W/Y/Z/AH.2
SFSC 1.a	RC SFSC a/b
SFSC 1.b	RC SFSC c
SFSC 2.a/b/c	VA SFSC a/b/c/d
SFSC 3 Cond.1.a	PIC SFSC b
SFSC 3 Cond.1.b	PIC SFSC c
SFSC 3 Cond.1.c	PIC SFSC b/d
SFSC 3 Cond.2.a/b	PIC SFSC b/c
SFSC 3 Cond.2.c	PIC SFSC d
SFSC 4 Cond.1.a	PIC SFSC a
SFSC 4 Cond.2.a	PIC SFSC b/c
SFSC 4 Cond.2.b	PIC SFSC b/c
SFSC 5.a	HR SFSC a
SFSC 6.a	HR SFSC c
SFSC 6.b	HR SFSC b
SFSC 7	CE SFSC c/ RLEC SFSC a/b/c/d
SFSC 8	CE SFSC a/b
SFSC 9	CE SFSC d
Supplementary Information 1	III.C.6/7
Supplementary Information 2	III.C.5
Supplementary Information 3	IV.AA.1/AF.1.a/2.a
Supplementary Information 4	N/A
Supplementary Information 5	N/A
Supplementary Information 6	IV.J
Supplementary Information 7	III.B.4
Supplementary Information 8	III.C.1
Supplementary Information 9	IV.N.2
Supplementary Information 10	III.B.3
Supplementary Information 11	III.C.2/HR SFSC b
Supplementary Information 12	N/A
Supplementary Information 13	N/A

EPG Step No.	EOP Step No.
Supplementary Information 14	N/A
Supplementary Information 15	N/A
Supplementary Information 16	III.B.6
Supplementary Information 17	IV.T
Supplementary Information 18	N/A
Supplementary Information 19	N/A
Supplementary Information 20	N/A
Supplementary Information 21	N/A
Supplementary Information 22	N/A
N/A	III.B.1
N/A	III.B.2
N/A	III.B.5
N/A	III.B.7
N/A	III.C.3
N/A	III.C.4
N/A	IV.E.2
N/A	IV.F.3
N/A	IV.F.5/6
N/A	IV.G.6
N/A	IV.I.6
N/A	IV.N.1/1.1
N/A	IV.Q
N/A	IV.R
N/A	IV.S.1.b/e/i/j/k
N/A	IV.U
N/A	IV.V
N/A	IV.AD.1
N/A	IV.AD.4.a/d
N/A	IV.AF
N/A	IV.AG
N/A	IV.AH.3

PROCEDURE NUMBER: EOP-5
PROCEDURE NAME: LOSS OF COOLANT ACCIDENT

SCOPE

EOP-5, Loss Of Coolant Accident, provides the operator actions which must be completed in the event of a Loss of Coolant Accident (LOCA). The actions in this procedure are necessary to ensure that the plant is placed in a stable, safe condition. The goal of this procedure is to mitigate the effects of a LOCA by isolating the break or establishing either long term core cooling using the safety injection system or the shutdown cooling system. These actions are designed to maintain adequate core cooling while minimizing any radiological releases to the environment.

GENERAL OVERVIEW

Prior to the implementation of this procedure, the post trip immediate actions of EOP-0 must have been completed. This procedure assumes that the immediate actions have identified the safety functions that are at risk, and have determined that a Loss Of Coolant Accident has occurred. The basis section of the Loss of Coolant Accident (LOCA) Recovery Procedure describes the LOCA transient in relation to the actions which the operator takes during a LOCA . The purpose of the basis section is to provide the operators with information, which will enable them to understand the reasons for, and the consequences of, the actions they take during a LOCA.

A LOCA is an accident that is caused by a break in the RCS pressure boundary. The break can be as large as a double ended guillotine break in the hot leg or as small as a break which results in a loss of RCS fluid at a rate that is just in excess of the available charging capacity of the plant.

Small and large break LOCAs differ in their effect on the post-LOCA RCS heat removal process. For a large break, the only path necessary for RCS heat removal in both the short and long term is the break flow with core boiloff. For small breaks, heat removal via the flow out the break is not sufficient to provide cooling and, therefore, steam generator heat removal is required. The procedure takes this into account with the decisions that must be made. Although distinct small and large break LOCA information is contained in the basis section of this procedure, the action steps to be used during the actual emergency do not require the operator to distinguish between break sizes.

A LOCA is characterized by an initial decrease in RCS pressure and inventory. Subsequent RCS inventory and pressure response depends on the size of the break. For large breaks inside containment, an increase in containment temperature and pressure occurs relatively soon after the LOCA. However, a small LOCA or stuck open PORV may not be detectable on containment temperature and pressure instruments in the short term.

The LOCA primarily affects RCS inventory and pressure control, and RCS and core heat removal. To a lesser degree, reactivity control, containment isolation, and containment temperature and pressure control are also affected. RCS inventory control is initially lost since the break flow rate exceeds the available charging pump capacity. For small breaks, RCS inventory control is regained via injection from the high-pressure safety injection (HPSI) pumps and the charging pumps. It is maintained in the long-term by injection from these pumps.

For large breaks, inventory control is regained through the injection of water into the RCS by the safety injection tanks (SITs) and the low pressure safety injection (LPSI) pumps. It is maintained in the long-term through the recirculation of sump water through the RCS by the HPSI pumps. Note that for large breaks, the RCS may not totally refill and pressurizer level may not be regained. If the large break is unisolable, continuous injection is required to make up for the loss out the break and to prevent boron precipitation. RCS pressure control is initially lost as the RCS depressurizes because of the loss of inventory out the break. For large breaks, the RCS depressurizes in 10 seconds to 3 minutes to pressures typically below 300 psia. In the case of the largest breaks, the RCS pressure will reach equilibrium with containment pressure, and will be nearly equal to that pressure. Because of the size of the break, the operator never regains direct control of RCS pressure and the RCS remains depressurized. For small breaks, the RCS depressurizes during the short-term (10 to 30 minutes) to an equilibrium condition with the steam generators. It then continues to depressurize as the operator cools down the steam generators. Pressure control is regained when the safety injection system (SIS) refills the RCS and pressurizer level is regained. Once pressure control is regained, subsequent small break post-LOCA operator actions which are associated with pressure control are (1) decreasing RCS pressure by means of auxiliary sprays, (2) controlling HPSI pumps and charging, (3) heat removal via the steam generators in order to establish shutdown cooling entry conditions and, (4) isolating the SITs. For small break LOCAs, during the period of time when the RCS is refilling (pressure control has not yet been achieved), there may be significant voiding in the RCS. The voided areas may be located in the reactor vessel head region, the RCS loops, or the steam generator U-tubes, and may be made up of steam or non-condensable gases. Steam voids may occur from fluid flashing in local hot spots within the RCS. This voiding is not a problem as long as heat removal is not inhibited or the ability to reduce primary pressure is not greatly reduced. The presence of small amounts of non-condensable gases may be present from sources such as gases evolving from the primary coolant and pressurizer vapor space. If their presence is detected in the RCS the reactor vessel head vent may be operated. The presence of non-condensable gases in the steam generator tubes is characterized by a decrease in primary to secondary heat removal capability. RCS heat removal is not jeopardized by the presence of non-condensable until a significant number of steam generator tubes are blocked. A significant number of tubes will not be blocked unless there is considerable oxidation of fuel cladding, and this is not expected for the small break LOCA, unless significant core uncovery occurs.

The large break LOCA heat removal process is not complex. For cold leg breaks the SIS maintains the core covered by providing only enough fluid to match boil off. The excess injected fluid spills out the cold leg via the break. The steam from core boil off passes out the hot leg and through the steam generators on its way out the cold leg break. For the hot leg break, the injected water builds up in the cold legs and provides the core with water for boil off heat removal and some single phase cooling. In the long term, heat removal is provided by simultaneous hot and cold leg injection. This process provides heat removal for either hot or cold leg large break LOCAs while providing the added benefit of ensuring adequate flushing of the RV to avoid buildup of non-volatile materials produced in the boil off cooling process.

The small break LOCA heat removal process is more complex than that described above for the large break. In the short-term, after the RCPs are tripped, core heat removal is maintained by natural circulation. Since the break is not large enough to adequately remove the heat, heat removal via a steam generator is required. This requires that the operator maintain feedwater (either main or auxiliary) to the steam generators and control steam flow from the steam generators via the turbine bypass system or the atmospheric dump valves.

The small break natural circulation process can take different forms. These forms include single-phase natural circulation and a more complex two-phase natural circulation. The simplest form of natural circulation is single phase, liquid cooling. Single-phase natural circulation is possible for cases where RCS inventory and pressure are controlled. Single-phase cooling transports heat using the same flow path involved in forced circulation cooling with the liquid density difference between SG and RV driving the flow. Two phase natural circulation involving steam and water is more complex and can take several forms, which depends on the amount of decay heat, the amount of inventory and pressure control degradation, the break size and the status of the SIS and the steam generators. One form of two phase natural circulation is known as reflux. In the reflux process, steam leaves the core region and travels to the steam generator via the hot leg; the steam is condensed in the steam generator before reaching the top of the "U" tubes and flows back to the core via the hot leg where it is once again turned to steam. Another two phase natural circulation process is similar to reflux but differs in that the steam from the core goes past the steam generator "U" bend and is condensed in the tubes on the cold leg side; thus condensate flows back to the core via the cold leg. A combination of the two processes is also possible.

Once RCS pressure and temperature are reduced, RCS heat removal is provided by the shutdown cooling system if possible. In the event that liquid inventory in the steam generators is not adequate to remove decay heat, or a source of feedwater is unavailable, the operator should implement the Functional Recovery Procedure because a multiple casualty condition is in effect (LOCA and Loss of All Feedwater). As discussed previously, although steam generator heat removal is only required for the small break LOCA event, the LOCA EOP does not require the operator to distinguish between large and small break LOCAs so the action is taken whenever SG heat removal capability is lost.

The actions contained in this procedure are designed to stabilize the plant following a Loss of Coolant Accident concurrent with a Loss Of Offsite Power and are a continuation of those actions begun in EOP-0.

The recovery actions contained in this procedure are to be carried out in parallel with the intermediate safety function check. This check, which is carried out approximately every 15 minutes, is a safety function check, which employs conservative acceptance criteria to allow the operator a higher level of confidence in confirming his initial event identification. If any safety function departs from the acceptance criteria, or the initial diagnosis was incorrect, then either the Function Recovery Procedure is implemented, or another Optimal Recovery Procedure is implemented after a new diagnosis is made using the Diagnostic Flowchart. If an Optimal Recovery Procedure is chosen, the Intermediate Safety Function Acceptance Criteria of that procedure must be verified prior to the transition.

The major actions in this procedure are designed to monitor the RCS depressurization, attempt leak isolation, monitor containment environment, borate the RCS, cooldown the RCS, restore S/G water levels, verify RAS, perform core flush and establish shutdown cooling. A final set of Safety Function Status Checks are then verified to be within their acceptance criteria which are more stringent than the initial set of acceptance criteria. This ensures that plant control functions have operated correctly along with manual operator actions to place the plant in a stable condition. It also demonstrates that plant conditions allow implementation of an appropriate procedure and the exiting of the emergency operating procedures.

Procedure Strategy and Information Flow

Prior to implementing the actions provided in the LOCA Recovery Procedure, the operator would have performed the Post Trip Immediate Actions and diagnosed the event. In the LOCA Recovery Procedure, the operator begins using the Safety Function Status Check to confirm that the plant is recovering. The first major action consists of monitoring RCS depressurization, maximizing safety injection flow into the RCS and attempting to isolate the source of the leak. This step reduces the risk of core uncovery and facilitates recovery from the LOCA. The second major action involves monitoring the containment environment to ensure that automatic protective functions have operated properly, and commencing RCS boration. The third major action is to commence an RCS cooldown and depressurization to SDC entry conditions. This step is particularly important for small breaks that require the S/Gs to remove the core decay heat. The fourth major action is to evaluate the need for HPSI and LPSI termination, and to monitor for core or RCS voiding. The fifth set of major actions are to ensure that the break is inside containment, verify RAS, restore containment environment, and restore forced circulation. The sixth major recovery action is the commencement of post-LOCA Long Term Cooling. MPT and low temperature conditions are established, and safety injection flow is switched to simultaneous hot/cold leg injection from the normal cold leg injection. Also, the suction for the charging pumps is switched to the refueling water tank for boron concentration control. The final major action is commencing normal SDC operation for small breaks, or a modified SDC for large breaks.

Section Number: II. ENTRY CONDITIONS

The EPG entry condition contains a qualifying entry condition that SIAS has not been blocked if the event has been initiated from Mode 3 or 4. The EOP does not contain this entry condition.

> *CCNPP utilizes an extensive set of Abnormal Operating Procedures that cover the entire range of lower mode events. Where conditions exist that the AOP would completely reproduce the EOP, the AOP directs that a direct entry into the appropriate EOP be made. For consistency, the operator is trained that for all lower mode events, the entry point is the AOPs, and the EOPs do not specify this entry condition.*

The Entry Conditions are chosen to reflect those conditions that are expected to exist prior to entering EOP-5. The EOP-5 Entry Conditions require that the Post-Trip Immediate Actions be completed and that conditions exist which indicate that a Loss Of Coolant Accident has occurred. The Post-Trip Immediate Actions, EOP-0, is required since it is the entry procedure for the entire EOP system, and must be implemented following any event which results in or should result in a reactor trip. EOP-5 is designed to respond to actions begun in EOP-0 if a RCS rupture has occurred. Indications that a LOCA has taken place include: an unexplained lowering of pressurizer level, an unexplained rise in pressurizer level, an unexplained lowering of pressurizer pressure, a loss of RCS subcooled margin, possible receipt of the Containment Radiation High alarm, and an unexplained rise in containment pressure, temperature, humidity or sump level.

An unexplained lowering of pressurizer level is expected from the release of RCS inventory from the break. It should be noted though that breaks located in the pressurizer may lead to increased pressurizer level since water from the hot leg flows into the pressurizer surge line while significant voiding of the RCS loop is occurring. If there is a break on or near the pressurizer level instruments, this may cause this instrument to be grossly inaccurate and misrepresent pressurizer level (high or low). A Safety Injection Actuation Signal may be actuated by either high containment pressure or low pressurizer pressure. Lowering pressurizer pressure will occur due to the loss of coolant and reactor power reduction following the trip. RCS subcooled margin will be reduced as pressure drops towards saturation without a significant reduction in RCS temperature. For a large break LOCA, subcooling will be lost and will not be regained. A rise in containment pressure, temperature, humidity or sump level is expected from the release of RCS coolant if the leak is inside containment. During a LOCA, the calculated peak vapor temperature exceeds the containment design temperature, this occurs only for a brief period during a time when the containment atmosphere is superheated. Due to condensation on the colder surfaces, the surface temperature of all structural and mechanical components in contact with the containment atmosphere remains at or below the saturation temperature for the steam in the containment. This temperature is below the containment design temperature. The Containment Radiation High alarm may be received for LOCAs inside the containment due to the activity contained in the RCS coolant escaping from the break. Quench tank parameters may be affected by the PORVs or Safeties passing inventory.

Section Number: III. PRECAUTIONS

The precautions listed are those which apply prior to or throughout EOP-5.

The EPG contains Supplementary Information that for small breaks in the RCS where the steam generators are important for heat removal, one steam generator must be used for this purpose even if primary to secondary leaks are detected. Use the unaffected steam generator, or the least affected steam generator, if both have primary to secondary leaks. The EOP does not contain this supplementary information.

> *The EOP SFSC for Core and RCS Heat Removal includes acceptance criteria that S/G level be maintained greater than (-)170 inches and the SFSC for Radiation Levels External to Containment includes acceptance criteria that S/G B/D and Condenser Off-Gas RMSs with no unexplained rise or alarms. If these criteria are not satisfied, indicating that a S/G is not available for heat removal or that a primary to secondary leak has occurred, then the LOCA procedure is exited and the Functional Recovery Procedure is implemented.*

The EPG contains Supplementary Information that the operator should be cautioned against prematurely initiating a RAS. This manual action should not be taken unless an automatic RAS is required and an adequate containment sump level exists (indicative of LOCA inside containment). The EOP does not contain this supplementary information.

> *The EPG states that the items contained within the Supplementary Information should be considered when implementing EPGs and preparing plant specific EOPs. The EPG states that the items should be implemented as Precautions, Notes, or in the EOP training program. Actuation of RAS and operator actions are covered in depth by operator training. In addition, this information has been incorporated into the production of the EOPs. In steps dealing with RAS actuation, the EOP verifies that containment sump level rises as RWT level drops and also verifies that containment sump level is adequate to support RAS during RAS actuation. The EOP states that RAS is verified to be actuated or manually actuated when level reaches 0.75 feet or the RAS actuation alarm has been received. These levels have been chosen such that adequate transfer from the RWT to the containment has taken place prior to RAS actuation.*

The EPG contains Supplementary Information that during the process of establishing entry conditions (RCS pressure and temperature) for SDC operation, it may be necessary to eliminate or reduce the size of the steam void in the reactor head. Ensure sufficient condensate availability to continue steam generator heat removal until the RCS pressure and temperature are reduced sufficiently, and SCS operation is accomplished. The EOP does not contain this supplementary information.

> *The EPG states that the items contained within the Supplementary Information should be considered when implementing EPGs and preparing plant specific EOPs. The EPG states that the items should be implemented as Precautions, Notes, or in the EOP training program. The EOP incorporates this information in the procedure by ensuring that condensate inventory remains available, that a S/G is maintained able to remove heat from the RCS and that voiding is monitored for and actions are taken to reduce voiding as necessary.*

The EPG contains Supplementary Information that when a void exists in the reactor vessel and RCPs are not operating, the RVLMS provides an accurate indication of reactor vessel liquid inventory. When a void exists in the reactor vessel and RCPs are operating, it is not possible to obtain an accurate reactor vessel liquid level indication due to the effect of the RCP induced pressure head on the RVLMS. The indicated level also differs for different RVLMS designs under these conditions. Information concerning reactor vessel liquid inventory trending may still be discerned. The operator is cautioned not to rely solely on the RVLMS indication when RCPs are operating. The EOP does not contain this supplementary information.

The EPG states that Supplementary Information should be implemented as precautions, cautions, notes, or in the EOP training program. The characteristics of Reactor Vessel level indication and the affects of voiding are covered in depth by training.

The EPG contains Supplementary Information that for those plants with use the Containment Spray System in conjunction with the Iodine Removal System, operation of the CS may be desirable in the event of an iodine buildup in containment. Since iodine may be released to the containment atmosphere at various times following event initiation. The EOP does not contain this supplementary information.

The EOP directs operation of containment spray based strictly on containment pressure, and not based on iodine removal. The EOP also directs verification that the iodine filter fans are running. At CCNPP, the iodine removal system starts automatically on CRS and CIS.

The EPG contains Supplementary Information that small breaks located at the top of the pressurizer [e.g., stuck open PORV or safety relief valve] will result in flashing and steam production in the reactor vessel and hot legs. This steam will flow towards the break through the pressurizer surge line and oppose the draining of the pressurizer liquid. Thus, the liquid level in the pressurizer may increase or exhibit erratic behavior due to the competing steam-water counter current flow condition. A similar behavior may be observed if the break is in the surge line. The EOP does not contain this supplementary information.

The EPG states that Supplementary Information should be implemented as precautions, cautions, notes, or in the EOP training program. The characteristics of a pressurizer break are covered in depth by training. The EOP includes a note that during a LOCA, pressurizer level may not provide an accurate indication of RCS inventory due to the formation of voids. This note encompasses any break location, including a break at the top of the pressurizer or in the surge line.

The EPG contains Supplementary Information that during recirculation at least one HPSI pump should be operating at all times unless HPSI termination criteria are met. The EOP includes instructions for HPSI operation after RAS actuation as procedure steps, and requires HPSI termination criteria to be met prior to stopping either HPSI pump. If Component Cooling is lost, then HPSI pumps are secured after initiating flow with a Containment Spray pump.

The EPG states that the items contained within the Supplementary Information should be considered when implementing EPGs and preparing plant specific EOPs. The EPG states that the items should be implemented as Precautions, Notes, or in the EOP training program. The EOP uses this information in the development of the procedure. The EOP directs that the HPSI termination criteria must be satisfied prior to throttling or terminating HPSI flow. This is reiterated in the step to ensure that a minimum HPSI flow of 90 GPM is occurring during RAS. Aligning a CS pump for SI and securing the running HPSI pumps, in the event a CC pump is not available ensures the maintenance of core cooling in the event of a loss of Component Cooling, which would cause the eventual loss of the HPSI pumps.

The EPG contains Supplementary Information that if restarting RCPs, consideration should be given to choosing pump combinations which will maximize pressurizer spray flow.

At CCNPP, there is not sufficient main spray flow to provide acceptable pressure control with only 2 RCPs operating. Auxiliary spray is used whenever any of the RCPs have been secured. The RCP combination used in the EOP is therefore, based on achieving the lowest NPSH of the pumps.

The EPG contains Supplementary Information that operators should be aware of the status of CCW supply to the RCPs and , if CCW has been isolated, should restore CCW if possible and desired. This is particularly true for plants which receive a CIAS for a low pressurizer pressure condition. The EOP does not contain this supplementary information.

The EPG states that the items contained within the Supplementary Information should be considered when implementing EPGs and preparing plant specific EOPs. The EPG states that the items should be implemented as Precautions, Notes, or in the EOP training program. The EOP incorporates this information in the procedure by a continuously applicable step in the RCP trip strategy that if CIS has actuated or component cooling flow can not be verified to the RCPs to trip all RCPs. The EOP then has a step that if component cooling has been secured to containment, to restore flow.

The EPG contains Supplementary Information that if pressurizer pressure is less than the PSV reset value and greater than the SIAS setpoint, and the operator suspects that a PSV is not fully closed, then pressurizer pressure may be intentionally lowered in an attempt to reset the PSV. When doing so, pressurizer pressure should be maintained greater than the SIAS setpoint and the minimum required subcooling shall be maintained. The EOP does not contain this supplementary information.

The EPG states that the items contained within the Supplementary Information should be considered when implementing EPGs and preparing plant specific EOPs. The EPG states that the items should be implemented as Precautions, Notes, or in the EOP training program. The EOP incorporates this information in the procedure step to attempt leak isolation.

The EPG contains Supplementary Information that before starting a RCP the operator should ensure that the pressurizer is at saturation conditions to support restart of the RCP. If a RCP is started with the pressurizer not at saturation conditions because of refill, RCS pressure may rapidly drop below minimum pressure to operate the pumps as a result of an out-surge. The EOP does not contain this supplementary information.

The pressurizer does not have adequate instrumentation to make the determination of saturation conditions during a transient. The placement of RCP restart steps and the steps to evaluate the need and desirability of RCP restart, place the actual restart at a time separated from any large inventory additions. RCPs would not be started shortly after a large inventory addition. Therefore a significant pressure drop due to a recent refill is not expected.

Step: A. Warnings:

None

Step: B. Cautions:

The EOP contains a caution that valid ESFAS and AFAS signals to equipment shall not be overridden or blocked unless specifically directed in this procedure. A valid signal is a signal that at the time of initiation, correlated to plant parameters (e.g., the monitored parameter actually reached its setpoint value). The EPG does not contain this supplementary information.

1. ESFAS and AFAS equipment directly support the functions required in the Safety Analyses. To maintain the assumptions contained in the Safety Analyses, equipment must be capable of performing their functions as designated. This procedure has been written to function in support of the Safety Analyses. It has been pre-determined when the Safety Analyses require or allow valid ESFAS or AFAS signals to be overridden or blocked, and specifically directs the performance of this activity. The definition of a valid signal is provided to allow the operator to respond to an invalid signal, which may inhibit the required response to support the Safety Analyses.

2. The operator should continuously monitor for the presence of RCS or core voiding and indications that voiding is threatening the ability to maintain adequate heat removal or inventory control. Voiding may interfere with RCS flow and heat transfer, as well as the ability to depressurize the RCS to establish conditions necessary to enter shutdown cooling. RCS and core voiding may be indicated by letdown flow greater than charging flow, rapid unexplained increase in pressurizer level during an RCS pressure reduction, loss of subcooled margin as determined using CET temperatures, or Reactor Vessel Water Level Low alarm. This precaution was added to Rev. 1 of EOP-5 to ensure consistency between the EOPs and CEN-152, Rev. 3 (Commitment to NRC during July 1989).

3. Solid water operation of the RCS should only be attempted in order to maintain a subcooled margin of 30°F. During solid water operations, any change in RCS conditions that has an affect on RCS volume has a significant effect on RCS pressure. These RCS condition changes include the direct addition or removal of RCS fluid, and volume changes due to expansion or contraction of RCS fluid from temperature changes. Therefore makeup, letdown, system heatup or cooldown will directly affect RCS pressure and should be closely monitored to avoid rapid pressure excursions. (Reference: Action Value Basis Document: EOP-23.01).

The EPG states to minimize cycles of pressurizer auxiliary spray whenever the temperature differential is greater than maximum RCS subcooling for PTS. The EOP cautions to minimize cycles of auxiliary spray whenever the temperature differential is greater than the TRM limitation.

4. The number of auxiliary spray cycles should be minimized when the temperature differential is greater than 400°F to minimize spray nozzle thermal stress accumulation factor. The TRM requires pressurizer temperature be limited to a maximum spray water temperature differential of 400°F. If this limit is violated, then the temperature must be restored to within limits within 30 minutes and an engineering evaluation must be performed to determine the effects of the out-of-limit condition on fracture toughness properties of the pressurizer. (Reference: Action Value Basis Document: EOP-18.02).

The EOP contains a caution that common failure of a standby pump or component is possible if started following a pump or component failure. The cause of the failure should be determined prior to starting or restarting a standby pump or component. The EPG does not contain this supplementary information.

5. If a pump or component fails, the cause of the failure should be determined prior to restarting or starting a standby pump or component to prevent a common failure. Common failure of a pump could occur when the pump being started is taking suction from or discharging to the same location as the failed pump. Examples of possible failures are cavitation failure due to loss of NPSH if both pumps were taking suction from a dry source or failure due to pumping to a dead head when both pumps are aligned to the same discharge path. Common failure to other components could occur if the component being started is aligned to be powered from the same source or to supply the same output as the failed component. An example of this would be aligning the component to be started to a faulty power supply which is operating in an under or overvoltage condition.

6. The use of equipment in the containment building when containment hydrogen concentration is greater than 4% should be minimized to reduce the possibility of hydrogen ignition. Consideration should be given to the importance of safety in equipment operation, the urgency of equipment operation, the use of alternative equipment located outside containment, and the current hydrogen level and the anticipated time to reduce hydrogen concentration to less than 4%. Hydrogen ignition could result in a breach of containment integrity and an uncontrolled release of the containment atmosphere to the environment. (Reference: Action Value Basis Document: EOP-13.02).

The EOP contains a caution that if VCT pressure is reduced by greater than 5 PSIG, the idle charging pumps may become gas bound if not started or vented. The EPG does not contain this supplementary information.

9. If VCT pressure is reduced by greater than 5 PSIG, gas may evolve out of solution in the idle charging pumps. In this condition the pumps may become gas bound. The idle charging pumps may be started or vented to remove the accumulated gas. (Reference: SOER 97-01, <u>Potential Loss of High Pressure Injection and Charging Capability From Gas Intrusion</u>; Action Value Basis Document: EOP-85.01)

Step: C. Notes:

1. Temperature, pressure, and level instruments are affected by ambient conditions. When ambient conditions change, the output from these transmitters will vary and correction factors must be used to obtain correct indications. The indicated ranges specified in this procedure have been evaluated for these effects. If the indicated value for a parameter deviates from the actual value to the extent that correction factors are required, a modified value designated by braces will be given.

   4.25 PSIG containment pressure is equivalent to a containment temperature of approximately 180°F. The pressure equivalent is used for temperature due to the single power supply to all containment temperature indicators. This definition was then used during the evaluation of parameters for instrument uncertainties. (Reference: I.M. Sommerville, BGE Nuclear Engineering Unit, NEU 94-161, memo to W.J. Lippold, dated May 26, 1994)

2. Hot leg and cold leg RTD temperature indication may be influenced by charging pump or SIS injection water temperatures, especially during low flow conditions under natural circulation. Therefore, multiple RTD and/or CET indications should be used to verify RCS temperatures when injection is occurring.

The EOP contains a note that during a LOCA, pressurizer level may not provide an accurate indication of RCS inventory due to the formation of voids. Pressurizer level when combined with RCS subcooling based on CET temperatures will indicate the core is covered. The EPG does not contain this supplementary information.

3. Void formation in the RCS may displace the water giving a false high pressurizer level indication. RCS subcooling and Reactor Vessel level indication will provide indication that the core is covered. Reactor Vessel level indication will only provide accurate level indication when the RCPs are stopped due to the effect of RCP induced pressure head. Core subcooling can also provide indication of core coverage and can be obtained from SPDS or from CET temperature. Additionally, a break in the top of the pressurizer will give a false indication of high level due to the rapid depressurization of the pressurizer.

The EOP contains a note that high energy line breaks may cause erratic instrumentation response depending on the magnitude and location of the break. The EPG does not contain this supplementary information.

4. A high energy line break may cause erratic behavior or even failure of instruments located in the vicinity of the break. If a high energy line break is suspected, indications of a parameter should be confirmed with other independent measurements, especially if a plant process (such as voiding or natural circulation) is being determined.

5. At least two independent indications should be used, when available, to evaluate and corroborate a specific plant condition since an incident could induce inconsistencies between instruments. Inconsistencies could arise due to fluctuations in system parameters induced by the event, or due to inaccuracies in the instrument output resulting from environmental, power source or other influences. Independent indications are those which derive from independent parameters. Four safety channel indications of a parameter confirm the operability of any one channel but should be combined with another independent measurement if a plant process such as voiding or natural circulation is being determined.

6. Do not adopt manual operation of automatically controlled systems unless a malfunction is apparent or automatic system operation will not support the maintenance of a safety function. Shifting systems to manual may impede the recovery process by increasing required operator actions. Additionally, operator attentions may be distracted from maintaining proper control due to dynamic plant conditions.

7. Systems shifted to manual operation must be monitored frequently to ensure correct operation. Systems not monitored frequently might drift out of control band and cause adverse effects on plant conditions and complicate the recovery.

Section Number: IV. ACTIONS
Step: IV.ACOMMENCE INTERMEDIATE SAFETY FUNCTION STATUS CHECKS.

The EPG step to confirm the diagnosis states to verify Safety Function Status Check Acceptance criteria are satisfied and to sample steam generators for activity with a contingency action to monitor other indications for SGTR. The EOP does not direct sampling of the steam generators for activity.

> *The EOP diagnoses the event utilizing a flow diagram in EOP-0. Confirmation is then performed using the Safety Function Status Check Acceptance criteria. The acceptance criteria use steam plant activity monitors to confirm diagnosis.*

The intermediate safety function status check is designed to confirm the operator's diagnosis of the event. The EOP-5 acceptance criteria have been derived from a combination of best estimate analysis and plant operating experience to reflect the range for each parameter that would be expected following a LOCA. Although they have been chosen to bracket a Loss of Coolant Accident, they still allow the operator some response time for restoring conditions outside the expected. The parameters that are checked were chosen to be easily accessible from the control room panels and to require no interpretation or interpolation by the operator. The operator is required to verify the Safety Function Status Check Intermediate Acceptance Criteria are satisfied every 15 minutes. This check provides an overview of the progress of the event and will be carried out by the STA (or person designated by the CRS). Each safety function is evaluated, using specific plant parameters, against narrowly defined acceptance criteria, so neither non-LOCA nor multiple events will remain within their bounds. Performing the check every 15 minutes ensures the safety functions remain satisfied and the core is being adequately cooled. If the Safety Function Status Check acceptance criteria are satisfied, then this guideline is adequately mitigating the effects of the LOCA. If any Safety Function Status Check acceptance criteria are not satisfied and the operator is unable to readily return the parameter to within limits, the diagnosis of Loss of Coolant Accident is in error, and this procedure is not adequately mitigating the event. In this case, either a transfer is made to the Function Recovery Procedure, or another Optimal Recovery Procedure after a new diagnosis is made using the Diagnostic Flowchart. If an Optimal Recovery Procedure is chosen, the Intermediate Safety Function Acceptance Criteria of that procedure must be verified prior to the transition.

Step: IV.B. DETERMINE APPROPRIATE EMERGENCY RESPONSE ACTIONS PER THE ERPIP.

This step prompts the control room staff to determine the appropriate emergency response actions. If a Transfer Cask loaded with irradiated Fuel Assemblies has been dropped in the Auxiliary Building it will be necessary to concurrently perform actions of AOP-6D. This will allow appropriate event classification and ensure appropriate actions are taken due to the potentially high radiation levels in the Auxiliary Building. Recovery actions should not be delayed while attempting to determine response actions. However, it is placed early in the procedure to allow notification of plant personnel to ensure that assistance is or will be available if needed.

Step: IV.C. OBTAIN PLACEKEEPER AND RECORD TIME.

The placekeeper provides the instructions for ensuring that the time of the event is recorded, and for tracking the status of steps in the procedure. Recording the entry time facilitates event documentation and reconstruction during the post trip review, and is used for time dependent steps. The step tracking section provides the operator with an easy means with which to track completion of each step, and may be used to update the crew on initiated and completed steps in the procedure during a briefing. It also provides the function of a table of contents for returning to steps that may have been bypassed because the conditions were not yet satisfied.

Step: IV.D. MONITOR RCS DEPRESSURIZATION.

This step provides the actions necessary to ensure RCS makeup is available during the depressurization. The Recovery Actions ensure SIAS has actuated and RCS makeup flow is maximized. The Alternate Actions establish makeup flow if SIAS actuation point has not been reached and also provide actions necessary to restore full RCS makeup flow if it is not maximized.

The EPG step to ensure SIAS is actuated when pressurizer pressure is less than SIAS setpoint is continuously applicable. The EOP contains a step that if pressurizer pressure is greater than the SIAS setpoint and containment pressure is less than the SIAS setpoint, initiate HPSI injection with two HPSI pumps, start all available charging pumps, block SIAS pressurizer pressure signals and when pressure is below 1270 PSIA to verify appropriate HPSI flow.

The intent of initiating SIAS in the EPG is to provide HPSI injection. The EOP ensures adequate HPSI injection. SIAS is not desirable in this situation because the operator is controlling the depressurization and maintenance of secondary equipment which may be vital to event recovery.

1/2. If pressurizer pressure has dropped to or below the minimum SIAS setpoint allowed by Technical Specifications of 1725 PSIA , then a SIAS should have initiated automatically. SIAS actuation is verified by ensuring that the alarm is received, the HPSI pumps are running and the HPSI header valves are open. The term verify requires the operator to take manual actions to place the component or system in the expected condition if automatic actuation has not occurred. If SIAS has not automatically actuated before pressure drops below the actuation setpoint, the operator must manually initiate a SIAS. If pressurizer pressure is greater than the SIAS setpoint and SIAS has not actuated, the operator should block SIAS and manually initiate HPSI and full charging flow. It was assumed that the Optimal Recovery Procedures would not be entered for 10 minutes after the initiation of the event. If the RCS cooldown and the associated depressurization (due to the contraction of the RCS) has not reduced RCS pressure below the SIAS actuation setpoint, then it was assumed that the operator could control RCS makeup during the event manually. Therefore, SIAS is blocked to maintain secondary equipment operating to aid in the recovery, and HPSI and charging flows are initiated to provide RCS makeup. HPSI flow is also verified to be in accordance with Attachment (10) when pressure is below 1270 PSIA to assure proper system lineup and operation. (Reference: Ian Sommerville, BG&E Nuclear Engineering Unit, NEU 92-445, memo to C.J. Andrews, dated December 30, 1992; SOER 94-01, Non-conservative Decisions and Equipment Performance Problems Result in a Reactor Scram, Two Safety Injections and Water-Solid Conditions, Action Value Basis Document: EOP-22.05, 22.13, 04.02)

3. Pressurizer pressure will respond during the accident according to the size and location of the leak. Safety injection system flow rate will follow pressurizer pressure according to the SI delivery curves of Attachments (10) and (11). SI system design provides two redundant trains of SI, but only one train operation is necessary to meet the intent of this step. Therefore, it may be optimum for RCS inventory recovery purposes to have two SI trains in operation delivering flow in accordance with the two pump curve, but one train in operation (one HPSI/LPSI pump running with flow in accordance with the one pump curve) is acceptable. Charging pumps may have to be manually restarted if an interruption of electrical power to the charging pump buses has occurred. In order to ensure injection of water into the RCS is occurring, SI and charging pumps should be started and system flow should be verified to be within the limits of Attachments (10) and (11) when pressure is below

the corresponding pump shutoff head. If SI flow is not in accordance with the Attachments, the operator should start and align 12 (22) HPSI pump if 11 or 13 (21 or 23) HPSI pump failed to start. Electrical power availablility for valves and pumps necessary for inventory control, and Safety Injection System valve lineup should be verified, as necessary to restore the appropriate equipment response. It must be noted, that maximizing charging and safety injection can result in excess RCS inventory, possible filling of the pressurizer to a solid condition, and a Pressurized Thermal Shock concern upon RCS heatup, fluid expansion, and subsequent RCS pressure excursion. Operators must be aware of these concerns and throttle/terminate the SI operation when the termination criteria are met.   (Reference: Action Value Basis Document: EOP-22.13, 22.14)

Step: IV.E. PERFORM THE RCP TRIP STRATEGY.

The RCP trip strategy ensures RCPs are secured for a small break LOCA (the hot leg case being more restrictive), while at the same time allowing two or more RCPs to remain running in the event of a non-LOCA. The incentive for stopping all RCPs during a LOCA is to minimize coolant inventory loss from the RCS. The incentive for operating the RCPs during non-LOCA depressurizing events is for better RCS pressure control, and to minimize voiding in the RV upper head area during cooldown.

The EPG specifies that if pressurizer pressure decreases to less than SBLOCA plateau pressure (1300 PSIA) and SIAS is actuated, to ensure one RCP is stopped in each loop and if RCS subcooling is less than minimum RCS subcooling, to ensure all RCPs are stopped. The EOP states that if RCS pressure drops to 1725 PSIA, as a result of the event, then trip RCPs so that either of the following pairs of RCPs remain running : 11A and 12B (21A and 22B) RCPs, or 11B and 12A (21B and 22A) RCPs, and to trip all RCPs if CIS has actuated, Component Cooling flow can not be verified to the RCPs, or if RCS temperature and pressure are less than the minimum pump operating limits. There is a note that subsequent operations to depressurize the plant under operator control are not considered a result of the event.

1. The RCP trip strategy used in the EOPs differs from the EPG in that the first two pumps are tripped at 1725 PSIA rather than 1300 PSIA. This more conservative setpoint was chosen because it uses the SIAS actuation setpoint and the associated SIAS alarms as a key for securing the pumps. While performing the immediate actions, the operator is instructed to trip two RCPs (in opposite loops) if pressurizer pressure drops to 1725 PSIA. This is repeated here to ensure that two pumps are tripped if pressure dropped to 1725 PSIA during the interval between accomplishing the step in the Post-Trip Immediate Actions and in the LOCA EOP. The EPG addresses tripping all RCPs for LOCA depressurization events meeting the following criteria: less than minimum RCS subcooling, RCS pressure less than SBLOCA plateau pressure (1300 PSIA). The criteria of minimum RCS subcooling, conclusively demonstrates the existence of a LOCA. As long as pressure is maintained above the minimum pump operating limits for operation of two RCPs (one in each loop), RCS subcooling will be maintained above minimum RCS subcooling when pressure is less than 1300 PSIA. Therefore if the LOCA depressurization event trip criteria are met, the RCPs would have already been tripped due to the minimum pump operating limits being more restrictive than the LOCA depressurization event trip criteria. (Reference: Action Value Basis Document: EOP-22.05).

   Subsequent operations to depressurize the plant, when under operator control, do not fit the guidelines for the trip two/leave two strategy. Early in the event the trip two/leave two strategy is implemented regardless of the nature of the event, which ensures protection from the associated effects of a LOCA event. The key is whether the depressurization is under operator control. If the depressurization is under operator control, the depressurization is then identified as not being associated with a LOCA event.

2./3. Additional requirements to trip the RCPs if RCS pressure is less than the minimum pump operating limits prevent pump damage, which might be caused by cavitation at low pressure. The RCPs will be operating in a pressure-reduced RCS and NPSH requirements may not be satisfied. The operator must continuously monitor RCP operating limits and trip any RCPs that do not satisfy RCP operating limits. Pumps are also secured on CIS actuation since Component Cooling flow is secured to the containment thus securing the cooling medium to the RCPs. The possibility exists that Component Cooling flow to the RCPs could be lost for reasons other than CIS. Therefore in addition to CIS, if flow can not be verifed to the RCPs, the operator is instructed to trip all RCPs. Tripping the RCPs on a loss of Component Cooling flow minimizes the possibility of pump damage due to insufficient cooling to the seals. (Reference: S.M. Mirsky, Principal Engineer - Analytical Support Unit, memo to J.F. Lohr dated November 13, 1986)

Step: IV.F. ATTEMPT LEAK ISOLATION.

Revision 1 of EOP-5 originally had this step as an alternate step for RCS pressure greater than 1725 PSIA and SIAS not actuated. The Combustion Engineering Owners Group report on Generic Letter 89-19 recommended that EOP-5 include isolation of unneeded primary systems as a separate step and accomplished as a primary action. (Reference: G.C. Creel, BG&E Vice President Nuclear Energy, letter to the NRC dated December 17, 1990)

Potential sources of leakage which can be rapidly and remotely isolated are checked and isolated, if possible, to minimize RCS inventory losses and to attempt to isolate the break.

1. Letdown is isolated to possibly isolate the break and to preclude loss of RCS inventory to the CVCS.

2. The PORVs are not expected to open during a LOCA. However, if they are the cause of the LOCA and pressurizer pressure is below 2300 PSIA, the PORV block valves should be closed, and the override handswitches should be placed in the override to close position, to maintain RCS inventory. 2300 PSIA is the pressure that is used for the design calculation M92-219 Rev 0 as the max pressure to isolate the PORV. (Reference: Action Value Basis Document: EOP-22.26)

The EOP contains a step that if a pressurizer safety valve is leaking and SIAS has not actuated, then attempt to reseat the pressurizer safety valve by reducing pressurizer pressure to 1800 PSIA. The EPG does not contain this step

> *The EPG contains Supplementary Information that if pressurizer pressure is less than the PSV reset value and greater than the SIAS setpoint, and the operator suspects that a PSV is not fully closed, then pressurizer pressure may be intentionally lowered in an attempt to reset the PSV. When doing so, pressurizer pressure should be maintained greater than the SIAS setpoint and the minimum required subcooling shall be maintained. The EOP incorporates this information in the procedure step to attempt leak isolation.*

3. If a pressurizer safety valve is leaking and SIAS has not actuated by the time the operator arrives at this step, the leak rate will be relatively small. Pressurizer pressure may be intentionally lowered to a value greater than the SIAS setpoint in an attempt to reseat the pressurizer safety valve. (Reference: Action Value Basis Document: EOP-22.28)

4. RCS sampling should be terminated and all sampling lines should be isolated. If necessary, this isolation should be performed manually. Isolating sampling lines minimizes the possibility of inadvertent personnel exposure, and minimizes RCS inventory losses.

The EOP contains a step to shut the reactor vessel head and pressurizer vent valves. The EPG does not contain this step

> *The EPG basis for the step to isolate the LOCA states if there are other plant specific systems which could isolate the LOCA, then they should be listed.*

5./6. Reactor Vessel or Pressurizer Vent Valves should be isolated. These valves may possibly be the source of RCS inventory loss. Shutting the valves ensures that leakage is minimized.

7. RCS to CCW leakage should be detected by the CCW radiation monitor indicating an upward trend. An increase in CCW head tank level may also be an indication of reactor coolant to CCW in-leakage. The operator should be aware though, that an increased CCW heat load, possibly caused by high containment temperatures, will also cause head tank level to rise to the point where an abnormally high level increase may possibly be discerned. If RCS to CCW leakage is evident, there are two possible sources of leakage, the RCP Seal Coolers or the Letdown Heat Exchanger. If the leakage is via the Letdown Heat Exchanger, having shut the Letdown Isolation Valves in previous steps should have isolated the leak. Due to CCW system being a closed system the CCW radiation monitor indication will remain high. If the leak has not been isolated, then the RCPs should be tripped and Component Cooling Containment Isolation Valves should be shut. (Reference: SOER 93-01, Diagnosis and Mitigation of Reactor Coolant System Leakage including Steam Generator Tube Ruptures.)

The EPG specifies if LOCA is outside containment as indicated by auxiliary building radiation monitor alarm or unexplained rise in auxiliary building sump levels to locate and isolate the leak, isolate the auxiliary building, initiate actions to make up to the RWT, verify CIAS is initiated and notify plant management. The EOP specifies, if LOCA inside containment can not be determined by rise in containment temperature, pressure, humidity or sump level, or the wide range noble gas monitor and main vent gaseous alarms clear, to place the penetration room exhaust fans in service, attempt to locate and isolate the leak and maintain RWT level greater than 2 feet by replenishment from any available source.

An increase in auxiliary building sump may be caused by leakage other than RCS leakage, therefore the EOP step is written to confirm the LOCA is inside containment. If this is not confirmed, then the LOCA is assumed to be outside containment. Appropriate personnel will be notified via ERPIP implementation.

8. Actions should be taken to verify that the leak is not outside of containment. A LOCA outside of containment is a very low probability event but if it does occur, and appropriate actions are not taken, the consequences can be severe. In this step, the containment environment and the Noble Gas Radiation Monitor and Main Vent Gaseous alarms are monitored for indications that the leakage is in the containment. If it is evident that a LOCA is occurring outside containment, then an attempt to locate and isolate the break should be made. Additionally, both Penetration Room Exhaust Fans should be placed in service to minimize exposure to plant personnel. If leakage is identified outside of containment, the affected system should be isolated either remotely or locally. After the completion of the previous steps, all major leakage paths from the RCS to outside the containment have been isolated, and leakage outside the containment is limited to systems such as charging or SI and possible check valve failures. (Reference: Action Value Basis Document: EOP-59.02)

The EPG contains a step that if the LOCA is isolated to go to step 47. The EOP moves the branching steps for an isolated RCS leak, which corresponds to EPG step 14, ahead of steps corresponding to EPG steps 10 through 12.

If the leak has been isolated and SIAS has not occurred, most of the remaining steps within EOP-5 are not necessary to be performed. If SIAS has occurred, then the leak size was significant enough to have lingering affects. These affects are mitigated by the same steps that would be applicable if the leak had not been isolated.

9. If the leak can be isolated and verified to no longer be threatening safety functions, and if SIAS has not actuated, then the operator is allowed to exit the LOCA EOP and implement EOP-1, Reactor Trip. It is anticipated that this will be possible for only very small LOCAs which are easily isolated, and for which no major effects on the plant have occurred. Since the event no longer threatens the plant's ability to satisfy the safety functions, most of the remaining steps within EOP-5 are not necessary to be performed. EOP-1 actions will place the plant in a safe and stable condition and establish the plant in hot standby or direct cooling down if necessary. Prior to implementing EOP-1, the operator must recover from actions that have been taken per this procedure. The HPSI pumps, which were started, must be stopped after ensuring that the termination criteria have been met, and then the HPSI header valves must be shut to return the SIS system to its normal standby condition. If power has been lost to components, but offsite power is available, the operator should recover the affected equipment prior to exiting this procedure. RCPs which have been secured as part of RCP trip strategy also need to be recovered since EOP-1 is not designed to respond to non-forced circulation situations. Finally, the operator should verify that the EOP-1 Safety Function Status Check Intermediate Acceptance Criteria are satisfied. If these acceptance criteria can not be satisfied, the operator should continue with EOP-5.

10. If the leak has been isolated, this step directs the operator to evaluate the need for a plant cooldown based on plant status, auxiliary systems availability and condensate inventory. If the continued availability of any systems required for maintenance of hot standby is in doubt, a cooldown should be performed before the ability to cooldown is lost. For example, if the available condensate inventory is marginally adequate, a cooldown should be commenced immediately to avoid running out of condensate before the shutdown cooling system can be placed into operation. Similarly, consideration should be given to the availability of compressed air and cooling water systems as well as the continued availability of electrical power. The operator should conduct a cooldown if any plant condition threatens to limit the ability of the plant to be maintained in hot standby, or the ability to be cooled down at a later time. Additionally, the extent of plant damage may require cold shutdown conditions in order to effect repairs and subsequent testing.

    Until the decision is made whether to cooldown the plant or not, the operator should continue to perform plant recovery actions in accordance with this procedure. If it is decided that a cooldown is not necessary, the plant should be maintained in a stable condition. Depending on the event and ESFAS actuations that have occurred, the appropriate plant recovery actions should be performed per this procedure until conditions exist to implement an appropriate procedure, as directed by the Plant Technical Support Center or the Shift Manager.

Step: IV.G. IF THE LEAK IS INSIDE CONTAINMENT,
THEN MAINTAIN THE CONTAINMENT ENVIRONMENT.

Containment environment is monitored to ensure that ESFAS actuates when required and to minimize hydrogen buildup that could result in hydrogen ignition. The engineered safety features systems limit the consequences of an incident by isolating the containment, and limiting the internal pressure by removing energy from the containment environment so that the structure design limits are not exceeded. This minimizes the potential for release of fission products by reducing the chances of containment rupture. For steam leaks inside the containment, heat transferred to the containment structure is removed by the containment cooling system, which is comprised of two subsystems, the containment spray subsystem and the air recirculation subsystem. The containment spray subsystem reduces pressure in the containment by condensing the containment structure steam and removing heat from the containment atmosphere by recirculation of the spray water through the shutdown cooling heat exchangers. The air recirculation subsystem reduces pressure and removes heat directly from the containment structure atmosphere to the service water system with recirculating fans and cooling coils.

1. The Containment Air Coolers are started in High with maximum SRW flow if SIAS has not actuated. This action initiates maximum cooling for the containment to help reduce pressure by condensing the steam cloud in an attempt to prevent ESFAS actuations initiated on containment pressure. If SIAS has actuated, then Containment Air Coolers should not be shifted to High due to the additional load resulting from containment spray. Upon receipt of a SIAS, all four cooling units are automatically started on or shifted to the low speed setting and, simultaneously, the full flow (8 inch diameter) service water outlet valves at each cooler are also opened. Each cooling unit is capable of handling one-third of the required cooling in the event of a steam line break inside containment by condensing water vapor and cooling the air-steam mixture.

2/3. ESFAS is verified to have actuated CIS and SIAS on high containment pressure. SIAS actuation is verified by ensuring that the alarm is received, the HPSI pumps are running and the HPSI header valves are open. CIS actuation is verified by ensuring that the alarm is received with the Component Cooling Valves shut. The term verify requires the operator to take manual actions to place the component or system in the expected condition if automatic actuation has not occurred. This step prevents direct communication between the containment atmosphere and the environment. Operators should be alert to the loss of auxiliaries to the containment which occur with containment isolation. Technical Specifications require that SIAS, CIS and CSAS actuate prior to 4.75 PSIG. The SIAS and CIS setpoint of 2.8 PSIG was established by a verbal commitment to the NRC to show conservatism with respect to the Tech. Spec. limits. Additionally, if CIS has actuated, RCPs are secured since Component Cooling flow is secured to the pumps. Securing the RCPs on CIS actuation minimizes the possibility of pump damage due to insufficient cooling to the seals. (Reference: Action Value Basis Document: EOP-04.02)

4. A study performed by IMPELL Corporation in 1988 showed that under high SRW heat loads caused by excessive containment temperatures from either a steam line rupture or LOCA, the normal SRW room ventilation system will not sufficiently maintain the SRW room temperatures below the FSAR limit of 130°F. The study resulted in a POSRC Outstanding Item #88-43-04. The Outstanding Item was closed at POSRC meeting #88-50 on June 1, 1988 by changes to OI-15 which verifies the normal ventilation system is operating and directs the operators to deenergize the normal lighting in the SRW room to reduce the heat load.

5. This step verifies ESFAS has actuated CSAS on high containment pressure. The term verify requires the operator to take manual actions to place the component or system in the expected condition if automatic actuation has not occurred. This check should consist of ensuring that the alarm is received, the Containment Spray Valves are open, Spray flow is indicated and the Condensate Booster Pumps have tripped. The Condensate Booster Pump check was added, due to SIAS starting the Containment Spray Pumps and the Containment Spray Valves failing open upon loss of Instrument Air to the Containment. This condition could initiate Spray flow without CSAS actuation. When considering the loss of power effects, the Condensate Booster Pumps were chosen, due to the breakers remaining shut until a trip signal is received. The function of the Containment Spray System is to limit the containment atmosphere pressure and temperature after a LOCA and thus reduce the possibility of leakage of airborne radioactivity to the outside environment. The containment spray system should automatically actuate at a containment pressure of 4.25 PSIG. The CSAS setpoint of 4.25 PSIG ensures CSAS will actuate prior to the Technical Specification limit of 4.75 PSIG. The capacity of the two containment spray pumps is so they can limit the containment pressure to less than its design value following a LOCA without giving credit to the containment coolers. (Reference: Action Value Basis Document: EOP-04.04, 42.01)

The EOP contains a plant specific step that if CSAS has actuated and either SRW header is not in operation, to verify containment pressure less than 10/25 PSIG and attempt to start a SRW Pump. If containment pressure has exceeded 10/25 PSIG, to isolate SRW to the CACs and attempt to start a SRW Pump on headers with associated DGs. If the SRW Headers can not be restored or not associated with a DG, the SRW Pumps and associated DGs are disabled. The EPG does not contain this step.

6. NRC Generic letter 96-06 prompted analyses to determine the effects of water hammer loads on SRW piping. During these analyses, it was discovered that actions to recover an idle header could have detrimental effects. SRW in a Containment Air Cooler will flash to steam when it reaches saturation temperature. During a design base LOCA/LOOP, the CAC fan coast down lasts longer than SRW flow coast down in the CAC. This subjects the CAC to containment temperatures greater than the SRW saturation temperature. If SRW flow is not immediately restored, a steam void can be created in the CAC and expand into the insulated piping. Subsequent restart of a SRW pump could create a water hammer with significant water hammer loads exerted on the SRW piping. Plant elevations may significantly alter the effects of less than design bases events. The A-train components, 11/21 and 12/22 CACs are located on the 45 foot inside the containment. The B-train components, 13/23 and 14/24 CACs are located on the 69 foot inside the containment. The SRW head tanks, which provide head and system expansion, are located on the 69 foot outside the containment. Analyses show that the CACs on the 45 foot will begin to void at 243 °F and the CACs on the 69 foot will begin to void at 215 °F. An entire CAC can be voided (approximately 30 ft^3 each) in 30 seconds. Once voided, flow restoration to the CAC can be restored by severely throttling the outlet of the CAC and pump restart, or allowing the void to cool and collapse prior to reinitiating flow. Restoration of flow to a voided CAC after the occurrence of a design base LOCA(ESDE)/LOOP has been determined to be 24 hours for the A-train CACs and 60 hours for the B-train CACs to allow the void to cool and collapse. It can be concluded that if containment temperature does not exceed the SRW saturation temperature in the CAC, then that SRW header

could be restarted without restriction. (Reference: Time Delay To Bring Failed SRW Pump Train Back In Service, CA06052)

Since the temperature values are analytical values, operator actions based on these temperatures require conservatism based on the instruments used. Containment temperature instruments are powered from 1/2Y10 and may not be available. The CSAS setpoint, 4.25 PSIG containment pressure, is equivalent to a containment temperature of approximately 180 °F. This value is used when defining Harsh Containment Environment conditions, and has an associated alarm that must be acknowledged by the operator. The 10/25 PSIG values were derived from the equivalent 16/31 PSIG values for 215/243 °F with a 6 PSI margin for instrument uncertainties. If containment pressure has not exceeded 10/25 PSIG, it is concluded that voiding has not occurred in the CACs, and SRW pump restart may be attempted without restriction. (Reference: I.M. Sommerville, BGE Nuclear Engineering Unit, NEU 94-161, memo to W.J. Lippold, dated May 26, 1994, M.T. Finley, Fuel Operating Services Unit, DE05679, Memo to S.C. McCord, dated March 31,2003)

System design assures required equipment operates under all design base conditions. This step may be used to restore additional equipment to operation or recover from multiple failures. Therefore, this step is placed after the primary mitigation actions and prior to restoring additional equipment to operation.

With SIAS and CSAS signals present, CAC flow is required to meet SRW pump minimum flow requirements. Once voided, CAC restoration by throttling valves was not evaluated due to the valves are butterfly type valves and the severe throttling required to slowly collapse and remove the voids. Fairbanks Morse Diesel Generators require SRW cooling. Continued operation of available Diesel Generators is desirable to improve event mitigation. Therefore, the option to isolate CACs and attempt to restore SRW flow to the Fairbanks Morse Diesel Generators is provided. Operation of a SRW pump with only a Diesel Generator as its load may not provide adequate flow to prevent cavitation at the impeller. However, this cavitation will only degrade pump performance in the long term. When manned, the Plant Technical Support Center should be consulted to evaluate continued operation of the SRW pump with only the Diesel Generator as its load, and establish specific event based restoration guidance.

7. Three significant sources of hydrogen exist during events where reactor coolant is lost into containment. The first source is from metal-water reactions involving zircaloy cladding surrounding the fuel. These reactions take place at high temperatures during the core uncovery phase of a LOCA. Thus, hydrogen generated will be released to the containment atmosphere if the primary break is inside containment. The amount of hydrogen produced depends on the duration of core uncovery and the maximum core temperature reached. The next source is from radiolysis of water by fission product decay. As a result of the decay of the fission products, water molecules in the RCS and in the RCS fluid that has been released into the containment may be broken down into hydrogen and oxygen. The gases are released to the containment atmosphere. This is the most significant long-term source of hydrogen. The last source is from corrosion of aluminum and zinc by the containment sprays. The reaction between the aluminum and zinc materials in the containment with the borated spray solution generates hydrogen. The reactions occur at higher rates with increasing temperatures, and depend on spray pH.

The operator should direct chemistry to place the Hydrogen Monitors in service in order to monitor for any buildup of Hydrogen. Due to bent tubing and missing supports, Unit-1 does not have the ability to sample the containment 189-ft. elevation.

The EPG step to operate hydrogen recombiners is step 41. The EOP places the step after the equivalent for the EPG step 11.

The EPG step is continuously applicable. By combining these steps into one continuously applicable step in the EOP, the operator has a single source of reference to control the containment environment.

8/9. Although hydrogen is not flammable until it achieves a concentration of at least 4%, it is prudent to reduce hydrogen to as low a concentration as possible. Such action minimizes the possibility of reaching the flammability limit and or forming pockets of high hydrogen concentration. Ventilation fans are started to reduce the possibility of forming pockets. The containment hydrogen concentration can be reduced by recombining hydrogen and oxygen to form water. The hydrogen recombiners do this by raising the temperature of the air passing through them to the point where the recombination reaction takes place. Electric heating elements are used to heat the incoming mixture, while flow through the units is provided by natural convection. The recombination rate (cubic feet of hydrogen removed per hour) depends on the hydrogen concentration in the atmosphere. One recombiner will generally remove hydrogen at a rate faster than it is generated. The recombiners take approximately 1 hour to reach operating temperature so no decrease in measured hydrogen concentration should be expected before this time. (Reference: Action Value Basis Document: EOP-13.01)

10. Above the lower flamability limit, the hydrogen recombiners become an ignition source. They should be secured to prevent a containment-wide hydrogen burn to avoid exceeding the containment pressure and temperature assumed in the safety analysis and minimize damage to safety related equipment located in containment. However, the containment atmosphere may be inerted by the presence of steam. The Plant Technical Support Center should be consulted to evaluate continued hydrogen recombiner operation. (Reference: Action Value Basis Document: EOP-13.02)

The EPG step to operate hydrogen purge system is step 43. The EOP places the step after the equivalent for the EPG step 11.

The EPG step is continuously applicable. By combining these steps into one continuously applicable step in the EOP, the operator has a single source of reference to control the containment environment.

11. The containment hydrogen concentration can also be reduced by purging the containment atmosphere with fresh air. The hydrogen purge system accomplishes this by providing controlled intakes to and exhausts from the containment atmosphere. This method of hydrogen control is utilized after the Plant Technical Support Center has evaluated several factors including the expected effects of a hydrogen burn. The hydrogen removal rate (cubic feet of hydrogen removed per hour) depends on the purge system flow rate, the containment free volume, and the containment hydrogen concentration. The hydrogen purge system will generally remove hydrogen at a rate faster than it is generated.

    The Plant Technical Support Center will monitor Containment radiation levels and hydrogen concentration in order to evaluate the environmental impact of any planned, or unplanned releases. The Plant Technical Support Center should obtain information concerning containment conditions, evaluate this information, and if necessary make the recommendation to operate the hydrogen purge system.

    Containment Hydrogen Concentration, Containment Pressure, dilution using the hydrogen purge system and expected effects of a hydrogen burn should be considered in the evaluation. If a hydrogen burn is not expected to threaten containment integrity, then radioactive releases to the environment could be minimized or avoided if the burn were allowed to occur rather than purging. In contrast, if a hydrogen burn is expected to result in containment pressure exceeding its design value, a continuous, unisolable release to the environment could occur. Containment conditions must be monitored and evaluated to ensure expected post-burn pressure will remain below design pressure. Conditions to monitor include: rate of increase of hydrogen concentration, hydrogen recombiner availability/capability, and rate of increase of containment pressure. If the expected post-burn pressure would exceed containment design pressure, then a hydrogen purge may be necessary to ensure continued containment integrity. The recommendation to purge will be made by the Plant Technical Support Center. The operators should operate the Hydrogen Purge System if this recommendation is made, and should continue to do so until the Plant Technical Support Center recommends its termination.

Step: IV.H. COMMENCE RCS BORATION.

In order to ensure reactivity control during the event, boration of the RCS is required to ensure adequate shutdown margin is maintained throughout the plant cooldown. The boration flowpath is verified if SIAS has actuated, and if the SIAS has not actuated, boration is commenced using charging pumps from the BAST. Boration is continued until adequate shutdown margin has been established.

1/2. It is anticipated that a SIAS will have actuated during a LOCA and therefore, the Recovery Actions include only those steps necessary to verify that the expected actions have occurred and boration is in progress via the normal SIAS flow paths. If SIAS has not actuated, the alternate actions initiate boration by lining up the charging pumps to take suction from the BAST.

3. The time RCS boration was commenced is recorded to provide a reference start point from which boration elapsed time can be determined. This time is needed when utilizing the charging elapsed time to determine when boration can be secured. (Reference: SOER 97-01, <u>Potential Loss of High Pressure Injection and Charging Capability From Gas Intrusion</u>)

4. The BAST levels at which RCS boration was commenced is recorded to provide a reference start point from which BAST level changes can be determined. These start levels are needed when utilizing the BAST level change to determine when boration can be secured. (Reference: SOER 97-01, <u>Potential Loss of High Pressure Injection and Charging Capability From Gas Intrusion</u>)

5. RCS boration should be continued until one of three conditions are met. The first case should be used if time permits. It specifies to establish the shutdown margin required by the NEOPs. This will minimize excessive boration of the RCS. If the operator does not have time to calculate the required shutdown margin, the other two cases will establish the required shutdown margin. Time has been added to the EOP, due to the possibility of losing the BAST level indication, if a loss of instrument air has occurred. The times listed in this step are the required elapsed time to achieve the same volume injected from the BAST. The times were calculated using a conservative 40 GPM charging pump flow rate. Since the calculation is cycle specific the calculation must be reviewed each cycle. (Reference: Action Value Basis Document: EOP-35.02)

   The chosen conservative values for Unit 1 cycle 15 boron requirements have been established for both units and will be maintained through subsequent cycles after review has shown these values remain conservative for the present cycle. (Reference: NEU 00-083, NEU 99-109)

   The caution is to alert the operator that excessive boration could lead to boric acid precipitation if core flush is required. The core flush calculation assumes a maximum of 7920 gallons of 8% boric acid being deposited in the RCS. (Reference: TSES Information Request Documentation Form TSES-2-0000222, Action Value Basis Document: EOP-35.04)

Step: IV.I. COMMENCE COOLDOWN.

This step directs the actions necessary to commence a cooldown in order to establish conditions which will allow establishment of shutdown cooling. A rapid plant cooldown via the steam generators is beneficial for all LOCAs, particularly small breaks. For small breaks, the steam generators are the major heat sink for RCS heat removal. An aggressive cooldown improves RCS heat removal by enhancing natural circulation and reflux boiling. Furthermore, an aggressive cooldown hastens the depressurization of the RCS. This results in higher safety injection flows, which aid in regaining RCS inventory control. For the largest breaks, the RCS depressurizes to an equilibrium pressure with the containment. In this condition, the RCS fluid is at a lower temperature than that of the steam generators. The steam generators, therefore, act as a heat source, superheating any steam in the RCS that may be flowing through the S/Gs to the break. By cooling down the S/Gs, heat input to the RCS is reduced.

1/2. This step assumes that the break in the RCS is small enough that containment pressure will be maintained below the CSAS actuation setpoint which cannot be blocked (CSAS shuts both MSIVs and the Main Feed Isolation Valves, and trips the SGFPs, Heater Drain Pumps and the Condensate Booster Pumps). If the MSIVs are open, then SGIS may be blocked in order to establish an RCS cooldown using the TBVs. However, if the MSIVs are shut, the ADVs will have to be used to establish a cooldown.

3. Following a loss of offsite power, a loss of condenser vacuum will occur due to the loss of condenser vacuum pumps, circulating water pumps, and the loss of sealing steam to the turbine seals. The MSIVs are shut to prevent main steam from the S/G from reaching the condensers, resulting in an overpressurization. Securing the S/G blowdown minimizes the heat input to the main condensers and reduces the possibilities of a water hammer event in the condensate system when power is restored, due to the heating of condensate in the S/G blowdown heat exchanger.

4. The operator should conduct a controlled cooldown at a rate of less than 100°F in any one hour in order to establish conditions for long-term recovery. During a controlled cooldown, the Tech. Spec. Cooldown Rate Limit of 100°F in any one hour should be adhered to. Additionally, a linear rate method should be applied. This means that a constant rate (e.g., 1.67°F/min) should be sustained throughout the cooldown. Operators should not intentionally induce large step changes in RCS temperature. The operating philosophy is to linearly decrease RCS temperature. A series of small step changes, which approximate a linear function, is one method to adhere to the prescribed cooldown rate limit. The heatup and cooldown rates for post-accident conditions are not specified within the Tech Specs. The operator must not intentionally exceed the specified Tech Spec limit unless it becomes necessary for reactor safety. The operator controlled cooldown should be aggressive to achieve cold shutdown as quickly as plant conditions allow. The specified cooldown rate is intended to allow a rapid cooldown while not complicating maintenance of subcooling. Maintaining RCS subcooling above 30°F for margin to the saturation limit takes precedence over maintaining the RCS cooldown rate. (Reference: Action Value Basis Documents: EOP-24.02, 24.03)

5. The large break LOCA will depressurize the RCS to containment pressure. Correspondingly, the temperature will be less than 300°F which satisfies one of the shutdown cooling entry criteria. During a large break LOCA, break flow cools the core. Steam Generators are decoupled from the rest of the RCS and are not the primary means of core heat removal. ECCS in-flow down the

vessel wall and flow out the break is the dominant cooling mechanism. The operator has little control over reactor vessel cooldown rate because of uncontrolled cooldown. The operator may be prompted to stop steaming the steam generators because of the large uncontrolled cooldown. If the steam generators are cooled below the RCS temperature, then the RCS will “see” the steam generator as a heat sink. It remains important to remove the stored energy from the SGs. A conflict may arise for the operator in implementing the SG cooldown strategy. The initial uncontrolled cooldown of the reactor vessel is beyond his control. Compliance with TS RCS cooldown rates is not possible until the system stabilizes. SG cooldown can be controlled by the operator. PTS is not a concern as long as the RCS is not allowed to rapidly repressurize. Reactor vessel wall delta-temperature stresses will dissipate with time.

The EOP contains a step to attempt to restore TBV and Condensate/Main Feedwater to operation. The EPG does not contain this step.

6. The use of the Turbine Bypass System to cooldown is desirable to enable greater cooldown capability when at lower RCS temperatures. By restoring main feedwater to service, the steam removed by the Turbine Bypass System may be reused. This essentially reduces the required amount of condensate inventory makeup to perform the RCS cooldown to zero.

Step: IV.J. DEPRESSURIZE THE RCS TO REDUCE SUBCOOLING AND MAINTAIN PRESSURIZER LEVEL.

The EPG contains supplementary information that if the initial cooldown rate exceeds Technical Specification Limits, there may be a potential for pressurized thermal shock of the reactor vessel and the Post Accident Pressure/Temperature limits should be maintained. The EOP contains this information as a Caution within the procedure.

> *The EPG states that the items contained within the Supplementary Information should be considered when implementing EPGs and preparing plant specific EOPs. The EPG states that the items should be implemented as Precautions, Cautions, Notes, or in the EOP training program. The EOP incorporates this information as a Caution in the block step describing maintaining RCS subcooling.*

This block step provides guidance for maintaining RCS subcooling and pressurizer level. These steps assume that the break is small enough that the safety injection and charging systems can keep up and exceed the loss of inventory from the break such that pressurizer level can be recovered. During a large break LOCA, this will not be possible due to the leakage rate, in which case the safety injection systems are maintained operating at their maximum capacity to ensure adequate core cooling.

The operator must know if a steam bubble exists somewhere in the RCS, or if it is water solid. By definition water solid conditions refer to the RCS effectively being full of subcooled water, with possible exception of some small pockets of non-condensable gases in high points of the system. Conversely, non-water solid conditions implies that there is a steam bubble somewhere in the RCS. The steam bubble could be located in the pressurizer, the reactor vessel head or the S/G U-tubes. A note is provided to aid the operator in making the determination. Pressurizer level or Reactor Vessel level indication alone may not confirm the bubble is saturated steam. By corroborating these indications with no rapid pressure excursions due to RCS inventory or temperature changes, actual RCS conditions can be ascertained.

For small break LOCAs, especially where RCS inventory and pressure are controlled, a deliberate depressurization of the RCS will be necessary to permit entry into shutdown cooling. By maintaining subcooling as low as possible, leakrate can be minimized and HPSI injection capability maximized. However adequate margin to minimum subcooling should be maintained for operator control.

The EPG step to maintain RCS pressure is step 24. The EOP combines the step with the equivalent for the EPG step 16.

> *Both EPG steps are continuously applicable. By combining these steps into one continuously applicable step in the EOP, the operator has a single source of reference to control RCS pressure/subcooling for the existing plant conditions.*

1. The subcooling values used, verify adequate core cooling and is the primary parameter used to validate pressurizer level indication as representative of total RCS inventory. If the RCS is subcooled throughout, then pressurizer level provides a usable indication of acceptable RCS inventory. During the initial phase of the LOCA while the loss of reactor coolant exceeds makeup, the pressurizer is expected to empty, the reactor vessel level is expected to drop and the subcooling

for the core will drop below the 50 to 70°F which is typical for an uncomplicated reactor trip. (Reference: Action Value Basis Documents: EOP-23.01, 23.03).

Subcooling should not be allowed to exceed 140°F in order to prevent pressurized thermal shock. If an overpressure situation exists then pressurizer heaters should be deenergized, main or auxiliary spray should be used to lower pressure, the cooldown rate should be lowered or HPSI/charging flow should be reduced. Main pressurizer spray is ineffective in controlling pressure when two or more RCPs are not operating. The cooldown rate should be limited to prevent overpressurization. SOER 82-07, which discusses the potential for pressurized thermal shock, recommends providing the operator with clear instruction on the proper course of action to effect a recovery to acceptable pressure and temperature conditions. This step provides the required actions for returning pressure to within acceptable limits if they were exceeded due to the RCS cooldown. The information recorded and caution will ensure compliance with the TRM. The actions were specifically ordered so the Auxiliary Spray isolation valves are opened prior to shutting the charging loop isolations. This ensures a flowpath is always available without dependence on the bypass around CVC-519. This is the preferred lineup recommended by NEU during their work to support charging flow requirement during a LOCA. The main spray header is isolated to ensure auxiliary spray flow is not recirculated back to the RCS. The pressurizer cooldown rate should be maintained less than 200°F/hour. This value will ensure compliance with the TRM. (Reference: SOER 82-07, Reactor Vessel Pressurized Thermal Shock; Action Value Basis Documents: EOP-18.01, 18.02)

If subcooling drops below 30°F, the operator should raise subcooling if possible by any of the methods listed. Caution should be observed if repressurization of the RCS is performed due to the possibility of pressurized thermal shock. The methods include operation of pressurizer heaters in order to increase RCS pressure, raising the RCS cooldown rate if cooldown has been commenced and raising HPSI flow if it was reduced. If subcooling can not be maintained greater than 30°F, safety injection must be maximized in order to ensure sufficient makeup. A note is included that Pressurizer Backup Heater Banks 11 and 13 (21 and 23) trip on U/V and SIAS. (Reference: Action Value Basis Document: EOP-24.02)

The EPG step to control the RCS during solid water conditions is step 53. The EOP combines the step with the equivalent for the EPG step 16.

Both EPG steps are continuously applicable. By combining these steps into one continuously applicable step in the EOP, the operator has a single source of reference to control RCS pressure/subcooling for the existing plant conditions.

2. This step is provided if the RCS is water solid. The goal of this step is to maintain the RCS within the limits of the P/T curves by controlling RCS temperature and pressure. When the RCS is intact and water solid, the RCS pressure is sensitive to changes in RCS inventory. If the RCS is intact and inventory and temperature are not controlled carefully, there is a potential for a pressure excursion that could overpressurize the RCS. Subcooling should not be allowed to exceed 140°F in order to prevent pressurized thermal shock. If an overpressure situation exists then RCS temperature should be reduced, HPSI/charging flow should be reduced, or pressurizer heaters should be deenergized. When reducing RCS temperature in a water solid condition, contraction of the RCS will affect RCS pressure to a greater extent than the temperature with respect to subcooling. Conversely reducing RCS temperature in a non-water solid condition will have little

effect on RCS pressure due to bubble expansion as the RCS contracts. Also, if the overpressurization is due to HPSI and/or charging flow, then the operator should verify that the HPSI termination criteria has been satisfied, and throttle or stop HPSI flow or charging pumps to restore and maintain pressure within limits. SOER 82-07, which discusses the potential for pressurized thermal shock, recommends providing the operator with clear instruction on the proper course of action to effect a recovery to acceptable pressure and temperature conditions. This step provides the required actions for returning pressure to within acceptable limits if they were exceeded. If subcooling drops below 30°F, the operator should raise subcooling if possible by any of the methods listed. Caution should be observed if repressurization of the RCS is performed due to the possibility of pressurized thermal shock. The methods include raising RCS temperature, raising HPSI flow if it was reduced, and operation of pressurizer heaters in order to increase RCS pressure. If subcooling can not be maintained greater than 30°F, safety injection must be maximized in order to ensure sufficient makeup. A note is included that pressurizer Backup Heater Banks 11 and 13 (21 and 23) trip on U/V and SIAS. (Reference: SOER 82-07, <u>Reactor Vessel Pressurized Thermal Shock</u>; SOER 94-01, <u>Non-conservative Decisions and Equipment Performance Problems Result in a Reactor Scram, Two Safety Injections and Water-Solid Conditions</u>, Action Value Basis Documents: EOP-23.01, 23.03)

The EPG step to maintain pressurizer level is step 23. The EOP places the step after the equivalent for the EPG step 16.

The EPG step is continuously applicable. The EOP places this step with steps to control RCS pressure/subcooling. Inventory control and pressure control are combined together since actions which affect one will affect the other.

3. The acceptable pressurizer level band was chosen with the intent of maintaining a saturated bubble in the pressurizer if possible, in order to simplify RCS pressure control. If pressurizer level drops to below 101 inches, then pressurizer heater operation will be interlocked off for overheating protection. The pressurizer level should be maintained between 101 {141} and 180 {190} inches, preferably about 160 inches. This will maintain the pressurizer heaters covered and avoid solid water operations. If level can not be maintained greater than 101 [141} inches, safety injection must be maximized in order to ensure sufficient makeup and cooling. (Reference: Action Value Basis Documents: EOP-19.01, 19.02, 19.06, 19.07)

Step: IV.K. EVALUATE NEED FOR HPSI OR LPSI THROTTLING/TERMINATION.

This step evaluates the need for termination or throttling of HPSI and LPSI flow.

1. If HPSI pumps are operating, then they must continue to operate at full capacity until HPSI throttling/termination criteria are met. Termination of HPSI should be sequenced by stopping one pump at a time while observing the termination criteria. Throttling of HPSI flow is permissible if all of the criteria are maintained. The termination criteria are:

   - RCS is at least 30°F subcooled based on CET temperature. Establishing 30°F of subcooling ensures the fluid surrounding the core is subcooled and provides margin for re-establishing flow should the 30°F of subcooling deteriorate when SIS flow is secured. Voids may exist in some parts of the RCS (e.g., reactor vessel head), but these are permissible as long as core heat removal is maintained. (Reference: Action Value Basis Document: EOP-23.01)

The EPG designates pressurizer level greater than minimum level for inventory control and not lowering. The EOP designates pressurizer level greater than low level heater trip setpoint.

Pressurizer level for minimum inventory control is 30 {90} inches. However to ensure that the pressurizer heaters remain covered for pressure control, the more conservative level is used. This conservative level then provides operator margin during the throttling evolution.

   - Pressurizer level greater than 101 inches {141}. A pressurizer level greater than 101{141} inches, in conjunction with the subcooling criterion is an indication RCS inventory control has been established. This value is based on the low level heater trip to ensure that the heaters remain available for pressure control. (Reference: Action Value Basis Documents: EOP-19.06, 19.07)

The EPG designates S/G level is being maintained or restored to the normal control band for HPSI throttle criteria. The EOP designates S/G level is greater than the minimum level for heat removal.

The intent of ensuring S/G level in the EPG is to ensure the S/G will be available to remove heat from the RCS. The EOP requires S/G level is greater than the minimum level required for heat removal. Requiring the normal control band would not permit HPSI throttling during level restoration above the minimum level for heat removal. Restoring S/G level, particularly when above the minimum required for heat removal, is restricted to a rate not to exceed the allowable cooldown rates. This timeframe when HPSI throttling would not be permitted may complicate the event with additional inventory, possibly imposing solid water operations when not required. This also maintains consistency of HPSI throttle criteria throughout the EOPs.

   - At least one S/G available for heat removal. A steam generator is available for heat removal if: 1) S/G level is greater than (-)170 inches, 2) capable of being supplied with feedwater, and 3) is capable of being steamed. The steam generator must be available to remove heat because the HPSI will no longer be adequate to remove decay heat from the core. Now the RCS must perform that function and there must be a means of removing heat from the RCS. (Reference: Action Value Basis Document: EOP-27.10)

- Reactor Vessel level is above the top of the hot leg. This provides an extra margin of core coverage and, taken in conjunction with the other criteria, serve as an additional indication adequate RCS inventory control has been established.

If all of the HPSI throttle criteria are met, then the operator may stop and/or throttle the HPSI pumps. When reducing HPSI flow, the operator is given a band to which plant parameters should be controlled. The operator may decide to throttle, rather than terminate the flow, if the SIS is to be used to control pressurizer level or plant pressure. Once the HPSI throttle criteria have been met, and HPSI flow reduced, the HPSI throttle criteria may be temporarily exceeded, so long as it is being promptly restored by operator control. A general assessment of the SIS performance can be made from the control room. Injection flow rates to each cold leg should be approximately equal. Departures from this would indicate a closed flow path or some system leakage. (Reference: Action Value Basis Documents: EOP-19.01, 19.02, 19.06, 19.07, 23.01, 23.03)

Continued operation of the high pressure injection pumps once the termination criteria are satisfied may lead to pressurized thermal shock conditions, and ultimately, can cause the RCS to repressurize to the PORV or safety valve setpoints. Due to the potential seriousness of pressurized thermal shock events and the fact that operator actions can either increase or decrease the severity of such an event, the operator must maintain awareness of the possible consequences of continuing flow once the criteria are satisfied. (Reference: SOER 82-07, <u>Reactor Vessel Pressurized Thermal Shock</u>)

2. If RCS pressure is able to be maintained at 200 PSIA or greater, then LPSI flow is not required. (Reference: Action Value Basis Document: EOP-22.18)

3. If the criteria for HPSI or LPSI termination cannot be maintained by the operator, then the appropriate SIS pumps should be restarted and full SIS flow restored.

Step: IV.L. RESTORE S/G LEVEL.

This block step provides the actions necessary to restore S/G water levels. At least one S/G level must be maintained to ensure a heat sink is available for removing heat from the RCS. Adequate RCS heat removal will be maintained as long as at least one S/G has feedwater capability so its level can be maintained and has steaming capability so energy can be removed from the S/G. The S/Gs are checked to ensure either main or auxiliary feedwater is maintaining adequate S/G water level. Maintaining at least one S/G as a heat sink available for RCS heat removal and cooldown is especially important in the case of a small break LOCA where RCS coolant leaking from the rupture is insufficient to remove the decay heat being produced. The Safety Analysis for Small Break LOCA assumes that the S/G tubes are covered during recovery to permit adequate HPSI flow. In addition, maintaining S/G water level above the top of the U-tubes provides sufficient static pressure head to prevent migration of containment radioactivity to the S/G secondary side. Condensate inventory is also checked to prevent a loss of feedwater from an inadequate feed source.

1/2. If the Main Feedwater System is available to supply water to the steam generator(s), then the shutdown feed system lineup should be used. Only one Main Feed Pump is required to provide the required post trip feed rate. Additionally, tripping one pump limits the probability and severity of overfeed events. All but one Condensate Booster Pump and two Condensate Pumps are secured to prevent pump damage under low flow conditions following the trip. With more than these prescribed pumps running, the miniflows do not provide the minimum flow requirements for each pump. As a result, pump discharge pressures rise and flow through the pumps drops. This raises the water temperature to saturation conditions and cavitation occurs in the pumps. Establishing the required lineup prevents pump suction cavitation. Heater Drain Pumps are secured since they are not required for low power operation. The Main Feedwater System would not be available due to the loss of condenser vacuum resulting from the loss of offsite power. Condenser vacuum will be lost due to the loss of condenser vacuum pumps, circulating water pumps, and the loss of sealing steam to the turbine seals. When Main Feedwater is operating and S/G level is restored to between 0 and (+)38 inches, or if operator control of feed flow is desired, then manual control of feed rate is established by shifting the Feed Regulating Bypass Controllers to Manual, and depressing the Feed Regulating Bypass Valve Reset Button. Depressing the reset button cancels the post-trip flow control signal which is automatically generated following a reactor trip, and therefore the operator must then take manual actions to maintain S/G level. Manual control is permitted to allow operator intervention should abnormal circumstances develop. During post trip recoveries where no abnormal circumstances develop, leaving the bypass valves in their post-trip flow position is preferred in most cases since it requires only periodic confirmation of the level recovery rather than dedicated operator attention, and thus minimizes the potential for overfeeding the S/G. If Main Feedwater is operating and 11 (21) Condensate Storage Tank cannot be maintained above 5 feet, then the operator should secure Main Feedwater and establish AFW so that 12 Condensate Storage Tank can supply feedwater. (Reference: Action Value Basis Documents: EOP-09.02, 24.02, 27.03, 27.12).

If Main Feedwater flow has been stopped for greater than 80 minutes, there is the possibility of waterhammer in the Main Feedwater system when feed flow is restored. The Main Feedwater piping entering the SG has a gooseneck installed prior to the main feed ring. If the water level is below the top of the gooseneck, a void can form in the gooseneck when temperatures equalize. This would only occur after an extended period of time. The top of the gooseneck is at the (-)7 inch level. Due to instrument uncertainties and the normal operating band, the gooseneck is conservatively assumed to be uncovered.

If the Main Feedwater system is not available, then Auxiliary Feedwater is established to the S/G to maintain levels. 11 or 12 (21 or 22) AFW Pumps are used, if available, since 13 (23) AFW Pump would be a large additional load on the diesel that is not required. If 13 (23) AFW Pump is used, the remaining load available on the diesel will be reduced and diesel fuel consumption will be increased. (Reference: Action Value Basis Documents: EOP-01.03, 27.03, 27.12, 33.01)

If either 11 or 12 (21 or 22) AFW Pumps are running, the AFW room ventilation system is verified to be operating to ensure the AFW pump room temperature remains below 130°F. This check was added due to NRC Inspection No. 50-317/85-03, Item No. 85-03-03. After the operator has established a RCS heat sink using the AFW system and the Atmospheric Dump Valves, the main feed system should be secured since it is no longer being used. Operating experience has shown that with all condensate pumps secured, waterhammer may occur in the condensate piping to the blowdown HX. This is the result of pipe depressurization, the long run of piping, residual heat in the piping and the addition of heat as the blowdown tank drains. Isolation stops the depressurization. (Reference: D.L. Shaw, BG&E Licensing, letter to NRC dated March 28, 1989; Action Value Basis Document: EOP-34.01)

3/4. The available condensate inventory should be monitored, replenished from available sources, or aligned as necessary to continually provide a source for a secondary heat sink. When CST level is low, it is important to ensure AFW pump flowrate is not excessive to prevent cavitation and vortexing. Vortexing is a major concern during the time when CSTs are being shifted, below 5 feet. During this time, flow should not be raised above that required to maintain S/G level constant. (Reference: Action Value Basis Document: EOP-09.01, 09.02, 45.01, CA04978)

Step: IV.M. CONTROL CORE AND RCS VOIDING.

During the cooldown, the possibility exists for the formation of significant voiding in the RCS. The voided areas may be located in the reactor vessel head region, the RCS loops, or the steam generator U-tubes, and may be made up of steam or non-condensable gases. Steam voids may occur from fluid flashing in local hot spots within the RCS. This voiding is not a problem as long as the ability to reduce primary pressure is not greatly reduced. The presence of small amounts of non-condensable gases may be present from sources such as gases evolving from the primary coolant and pressurizer vapor space. If their presence is detected in the RCS the reactor vessel head vent may be operated. The presence of non-condensable gases in the steam generator tubes is characterized by a decrease in primary to secondary heat removal capability. RCS heat removal is not jeopardized by the presence of non-condensables until a significant number of steam generator tubes are blocked. A significant number of tubes will not be blocked unless there is considerable oxidation of fuel cladding, and this is not expected.

During the cooldown, the operator should continuously monitor for the presence of voids. Voiding may cause RCS pressure to remain high and prevent RCS cooldown. Any time it is found voiding inhibits RCS depressurization to shutdown cooling entry conditions, then an attempt at elimination of the voiding should be made.

1. If voiding causes difficulty in depressurization, then the voids should be reduced or eliminated if possible by verifying letdown is isolated, stopping the depressurization and raising RCS subcooling, or cooling the S/G. Verifying letdown isolated minimizes further inventory loss through the CVCS. Stopping the depressurization prevents further growth of the void and raising RCS subcooling, should condense the void. Pressurizing has the effect of filling the voided portion of the RCS with cooler fluid, which will remove heat from the region. Subsequent depressurization and a repeating of this process several times will cool and condense the steam void. (Reference: Action Value Basis Documents: EOP-23.01, 23.03, 24.02)

   In the case of a void in the reactor vessel, the pressurization and depressurization cycle will produce a fill and drain of the reactor vessel. The pressurization can be accomplished by use of pressurizer heaters, raising RCS cooldown rate or increasing inventory. The operator is warned by a caution though, there is a potential for pressurized thermal shock from repressurization of the RCS following an excessive RCS cooldown. If indications of unacceptable RCS voiding continue, then voiding may be caused by non-condensable gases. Operation of the reactor vessel head vent will clear trapped non-condensable gases. Pressurizer and Reactor Vessel level should be monitored for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

   If indications of unacceptable RCS voiding continue, and voiding is suspected to exist in the steam generator tubes, then the S/G should be cooled by steaming or blowdown, and/or feeding to condense the tube bundle void. This will be effective for condensing steam voids but will not have an effect on non-condensable gases trapped in the tube bundle. A buildup of non-condensable gases in the tube bundles will not hinder natural circulation even with a large number of the tubes blocked. This is due to the small amount of heat transfer area required for the removal of decay heat. Monitor pressurizer level for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination. There is a caution prior to this step that warns the operator a rapid RCS pressure reduction will occur when the voids collapse if they were present in the S/G tubes.

Step: IV.N. MAINTAIN RCS FLOW VERIFICATION.

This step verifies adequate RCS flow is being maintained to remove heat from the core and transfer it to the S/Gs. If adequate flow cannot be verified, then RCS and Core Heat Removal Safety Function may become jeopardized if the condition cannot be remedied. Operators should ensure RCS pressure and inventory, and S/G steaming and feeding are being controlled properly to prevent violation of a safety function.

The EOP contains a step to verify the temperature differential across the core is less than 10°F if any RCPs are in operation, and a step to trip all RCPs if the temperature differential is greater than 10°F. The EPG does not contain these steps.

1. If RCPs are operating, the temperature differential across the core is verified to be less than 10°F. As long as RCPs are operating, differential temperatures are not expected to exceed 5°F. Verifying that the differential temperatures remain below 10°F ensures that proper flow is being obtained from the operating RCPs and that a malfunction such as a RCP shaft uncoupling has not occurred. (Reference: Action Value Basis Documents: EOP-24.01)

2. If all RCPs have been secured, then natural circulation is monitored by heat removal via at least one S/G. Natural circulation flow should occur within 5 to 15 minutes after the RCPs were tripped as long as inventory and pressure are controlled. A note is included prior to this step to inform the operator verification of an RCS temperature response to a plant change during natural circulation can not be accomplished until approximately 5 to 15 minutes following the action due to the increase in loop cycle times.

   Natural circulation is governed by decay heat, component elevation, primary to secondary heat transfer, loop flow resistance, and voiding. Component elevations on Combustion Engineering plants are such that satisfactory natural circulation decay heat removal is obtained by fluid density differences between the core region and the steam generator tubes.

   The operator has adequate instrumentation to monitor natural circulation for the single-phase liquid natural circulation process. The RCS temperature instrumentation can be used along with the other information to confirm the single-phase natural circulation process is effective. The natural circulation process involving two phase cooling is complex and varied enough so that RCS loop differential temperatures may not be a meaningful indication of adequate natural circulation cooling.

   The RCS temperature response during natural circulation will be slow as compared to a normal forced flow system response time of 6-12 seconds, since the coolant loop cycle time will be significantly longer (5 to 15 minutes). When single-phase natural circulation flow is established in at least one loop, the RCS should indicate the following conditions:

   - RCS subcooling at least 30°F based on CET temperatures. Adequate subcooling ensures that an adequate amount of fluid in its desired status is available to remove decay heat. During natural circulation, CET subcooling should be used to determine if adequate subcooling exists. The CETs do not rely on loop flow for detecting fluid conditions adjacent to the core and therefore will be the most accurate indication of core temperature. (Reference: Action Value Basis Documents: EOP-23.01).

- T_{HOT} minus T_{COLD} less than 50°F. T_{HOT} minus T_{COLD}, with two S/Gs operable, is expected to be about 20 to 25°F. If only one S/G is available during natural circulation, as would be the case if one S/G was unable to be fed or steamed, the differential temperature is expected to be about 40 to 50°F. (Reference: Action Value Basis Document: EOP-24.08).

- T_{HOT} and T_{COLD} constant or lowering. After natural circulation has been established, hot and cold leg temperatures should remain constant or be lowering. If the RCS is being cooled down, then the heat removed from the RCS should exceed the heat generated by decay heat and RCS temperature should lower. A rise in RCS temperatures indicates proper heat removal is not being maintained.

- CET temperatures trend consistent with T_{HOT}. Hot leg RTD temperature should be consistent with core exit thermocouples. Adequate natural circulation flow ensures core exit thermocouple temperatures will be approximately equal to the hot leg RTDs temperature within the bounds of the instruments' inaccuracies. Generally speaking, the CET temperatures will be somewhat higher than T_{HOT}. Since the steaming rate affects RCS temperatures, the margin of agreement between the CETs and T_{HOT} will vary. The critical area of concern here is to verify a general temperature trend using RTDs as primary indicator of RCS temperatures and the CETs to verify the trend. T_{HOT} indicated temperature response should be similar to the CET temperatures for RCS. For example, if T_{HOT} is constant, then CET temperatures should remain relatively constant. Likewise, if T_{HOT} increases or decreases, then CET temperatures should also increase or decrease, although there may be a small time lag involved before the CET temperatures change. (Reference: Sam Moore, BG&E E&C Systems Engineering Unit, memo to John Wilson dated April 3, 1991)

The EPG contains a step to ensure proper control of steam generator feeding and steaming as a contingency action. The EOP states to ensure steaming rate affects RCS temperatures and has a note that states verification of RCS temperature response to a plant change during natural circulation takes approximately 5 to 15 minutes following the action due to increased loop cycle times.

The EOP has already established proper control of steam generator feeding and steaming in previous steps. Including this check in the verification provides corroborative indications.

- Steaming rate affects RCS temperatures. Natural circulation is governed by decay heat, component elevations, primary to secondary heat transfer, loop flow resistance, and voiding. As previously mentioned, component elevations on CE plants are such that satisfactory natural circulation decay heat removal is obtained by fluid density differences between the core region and the steam generator tube sheet. Steaming rate affects the cold leg temperatures and density. This affects the magnitude of thermal driving head developed and therefore the amount of natural circulation flow. This will in turn affect hot leg temperatures since core flow is raised. When steam flow is adjusted, it should result in positive response in cold and hot leg temperatures with the major change being seen in cold leg temperatures.

The small break natural circulation process can take different forms. These forms include single phase (subcooled) natural circulation and a more complex two phase natural circulation. The simplest form of natural circulation is single phase, liquid cooling. Single-phase natural circulation is possible for cases where RCS inventory and pressure are controlled. Single-phase cooling transports heat using the same flow path involved in forced circulation cooling with the liquid density difference between SG and RV driving the flow. Two phase natural circulation involving steam and water is more complex and can take several forms, which depends on the amount of decay heat, the amount of inventory and pressure control degradation, the break size and the status of the SIS and the steam generators. One form of two-phase natural circulation is known as reflux. In the reflux process, steam leaves the core region and travels to the steam generator via the hot leg; the steam is condensed in the steam generator before reaching the top of the "U" tubes and flows back to the core via the hot leg where it is once again turned to steam. Another two phase natural circulation process is similar to reflux but differs in that the steam from the core goes past the steam generator "U" bend and is condensed in the tubes on the cold leg side; thus condensate flows back to the core via the cold leg. A combination of the two processes is also possible.

For cases where two-phase natural circulation cooling is the heat removal process, the operator relies upon maintaining the steam generator heat removal process and the strict rules that require the SIS to remain operating to restore inventory control. In addition, the core exit thermocouple temperature indication is important in monitoring heat removal during two-phase natural circulation cooling. As long as these temperatures remain less than superheat, they indicate that heat removal and inventory functions are being satisfied.

The time frame for the transition from single-phase liquid natural circulation cooling to the reflux mode is determined by the relative size of the small break. The operator should be aware that this transition might cause confusing temperature indications as the RCS loop differential temperatures readjust to reflect the transition in progress. Because the two-phase natural circulation processes are more complex, loop differential temperature is not an indicator of effective natural circulation. The emphasis in the procedure is to continue the steam generator heat removal process, continue restoring inventory control, and to continue monitoring the core exit thermocouples to confirm the heat removal process is adequate.

- Charging pumps and SIS flow ensure that a deliberate effort is being made to replenish RCS inventory. SI flow alone is acceptable to satisfy the intent of the step if no charging pumps are available and SI flow is in accordance with the Minimum Flow for Required Core Cooling table on Attachment (10).

The EPG designates S/G level is being maintained or restored to the normal control band. The EOP designates S/G level is greater than the minimum level for heat removal.

The intent of ensuring S/G level in the EPG is to ensure the S/G will be available to remove heat from the RCS. The EOP requires S/G level is greater than the minimum level required for heat removal. The EPG allows level to be restoring to the normal band. This permits level to be below the minimum level required for heat removal, which would not support adequate cooling. This also maintains consistency of defining a S/G available for heat removal throughout the EOPs.

- At least one S/G available for heat removal. A steam generator is available for heat removal if: 1) S/G level is greater than (-)170 inches, 2) capable of being supplied with feedwater, and 3) is capable of being steamed. The steam generator must be available to remove heat because the HPSI will no longer be adequate to remove decay heat from the core. Now the RCS must perform that function and there must be a means of removing heat from the RCS. (Reference: Action Value Basis Document: EOP-27.10)

- CET temperature is the best available indication that the core is covered and that core heat removal is effective. Due to the low pressures associated with LOCA events, the variable superheated temperatures indicative of core uncovery must be determined. The margin to superheat is to account for instrument uncertainties while at saturated conditions. If core uncovery occurs, temperature of the superheated steam will rise above this margin. Core uncovery indicates an advanced phase in the approach to inadequate core cooling and is undesirable. If at anytime core uncovery is approached or indicated, the operator should review the effectiveness of earlier measures and take all possible steps to restore the inventory to at least a core covered condition as indicated by the CETs, Subcooled Margin Monitor, or Reactor Vessel level indication. Core covered as indicated by Reactor Vessel level indication and CETs not superheated are corroborative indications that core heat removal is adequate. (Reference: Action Value Basis Document: EOP-24.33)

Step: IV.O. SHIFT THE CHARGING PUMP SUCTION SUPPLY TO A LOWER BORIC ACID CONCENTRATION SOURCE.

This block step provides methods to shift RCS boration to a supply with a lower boron concentration (i.e., the RWT or to the VCT). Proper shutdown margin must be maintained. This realignment from a concentrated boron source to a lower concentration source is made in order to avoid excess boration and to minimize the amount of waste generation during a subsequent startup where the RCS boron concentration must be reduced by dilution to the proper concentration. Boration or makeup will be from either the RWT or, if time permits, the VCT can be used after a blended makeup mixture has been determined.

Step: IV.P. CHECK CONTAINMENT SUMP LEVEL RISING.

The EPG step to confirm LOCA is inside containment specifies that if containment sump level is not rising as RWT level drops, confirm LOCA is outside containment, initiate actions to make up to the RWT, verify CIAS is initiated and notify plant management. The EOP specifies to maintain RWT level greater than 2 feet by replenishment from any available source and determine the cause for the leakage and attempt to isolate it.

> *The step to verify the leak is inside containment has already been performed early in the procedure. CIS will perform no functions to isolate a LOCA outside containment. Appropriate personnel will be notified via ERPIP implementation.*

The operator should monitor refueling water tank level. For RCS breaks inside containment, a decreasing trend in RWT level should correspond to an increasing trend in containment sump level. This action enables the operator to trend RWT level and to anticipate possible problems in actuating a RAS if the LOCA is outside of containment. If a decreasing trend in RWT level cannot be correlated to an increasing containment sump level, then the LOCA may be outside of containment. For LOCAs outside containment, RWT level should be maintained above the RAS setpoint by replenishment from available sources, and the location of the leakage should be determined so that isolation can be attempted. This will prevent the inadvertent air binding of the SIS pumps and the subsequent loss of makeup to the RCS due to alignment of the pump's suctions to a dry sump. (Reference: Action Value Basis Document: EOP-59.02)

Step: IV.Q. PROTECT ECCS PUMPS FROM OVERHEATING.

The EOP contains a plant specific step that if any ECCS Pumps are operating, to protect ECCS Pumps from overheating by commencing ECCS Pump Room cooling. Open the ECCS Pump Room Air Cooler Saltwater Valves, then start the 11 (21) East and 12 (22) West ECCS Pump Room Cooling Fans. The EPG does not contain this step.

The heat load on the ECCS Pump Room during a LOCA scenario is sufficient to cause the ECCS Pump Room Coolers to cycle. Constant cycling of the coolers may lead to failure and loss of ECCS functions. This step manually starts the ECCS Pump Room Coolers, which will stop the cycling. This protects the ECCS pumps from overheating during a LOCA scenario that requires operating the ECCS Pumps. (Reference: K.B. Cellars, BGE Design Engineering, ME940513.012, letter to J.E. Stanley, dated March 11, 1994)

Step: IV.R. PREPARE FOR RAS ACTUATION.

The EOP contains a plant specific step when RWT level drops to 4 feet that if CSAS has not actuated to place both containment spray pumps in pull to lock, place the safety injection pump recirc lockout switches in on and verify minimum HPSI flow. The EPG does not contain this step.

If CSAS has not actuated by the time the RWT level drops to 4 feet (indicated), calculations have shown CSAS will not be required. If the Containment pressure were to increase after the Containment Spray pumps are placed in Pull to Lock, conservative calculations show the increase would be slow with a peak Containment pressure below the design basis accident pressure. Placing the SI Pump Recirc Lockout Switches in ON allows the safety injection mini-flow returns to the RWT to shut upon initiation of an RAS signal, which prevents sending contaminated water outside the plant. The mini-flow bypass valve system must be designed such that no single failure could result in the loss of the ECCS function during the injection mode, or prevent proper isolation of the refueling water storage tank during the recirculation mode. By observing 90 GPM HPSI pump flow per pump immediately after turning SI Pump Recirc Lockout Switches to ON, if a single failure occurs and the valves close prior to RAS, the pumps are not threatened since sufficient flow has been verified. (Reference: Ian Sommerville, BG&E Nuclear Engineering Unit, NEU 93-035, memo to R.K. Bleacher, PD&MAU, dated February 5, 1993; Action Value Basis Documents: EOP-12.01, 59.03)

Step: IV.S. VERIFY RAS ACTUATION.

The EPG contains a step to ensure the auto start function for all idle CS pumps is disabled. The EOP does not contain this step.

The EPG contains steps to secure all but one CS pump early, and the termination step is sequenced before RAS actuation may occur. The purpose of early termination is to reduce Sump flow. When RAS occurs, the switch over from the cold RWT water to the hot sump water is expected to result in a containment pressure rise. This rise may be sufficient to re-actuate CSAS and start idle pumps. The EOP does not perform early CS pump termination.

The EOP contains plant specific steps to ensure minimum containment sump level, align a second component cooling water heat exchanger, commence ECCS pump room cooling, place ECCS pump room exhaust filters in service and maintain SRW and component cooling temperatures within the block step to verify RAS initiation. The EPG does not contain these steps.

For breaks located inside containment, if the RWT level falls to 0.75 feet, then the operator should verify RAS actuation by checking the alarm is received, LPSI pumps stopped and Containment Sump valves are opening. The term verify requires the operator to take manual actions to place the component or system in the expected condition if automatic actuation has not occurred. RAS is actuated either automatically or manually in order to maintain a continuous flow of safety injection fluid to the RCS (required for inventory control) and a continuous flow of containment spray water (required for containment temperature and pressure control). RAS does not automatically close RWT outlet valves. They must be manually closed to isolate the RWT from the SIS pumps. Containment sump level of at least 28 inches will ensure adequate NPSH for any operating SI or CS pumps when they are operating at their design flowrates. The containment sump level will be at approximately 14 ft 5 inches at the time of RAS. This level is equal to an indicated wide range level of approximately 53 inches, with no instrument uncertainties. (Reference: SOER 97-01, Potential Loss of High Pressure Injection and Charging Capability From Gas Intrusion; Action Value Basis Documents: EOP-43.01, 59.01)

A LOCA outside of containment will result in inadequate containment sump inventory to allow recirculation. The operator should not prematurely initiate an RAS. A possible complication of a premature RAS is the pumps' suction being aligned to a dry sump, resulting in air binding of the pumps and loss of both heat removal loops. In addition, for events where high containment pressure is present, the check valves in the RWT outlet line may be forced shut and the RWT fluid will remain unavailable while the containment is pressurized.

Verifying RAS lineup is in accordance with Attachment (6), RAS Verification Checklist, verifies equipment that is designed to function on a RAS has correctly actuated.

Shutting RWT Outlet Valves minimizes the possibility of air binding of the SIS pumps, and eliminates the chance of backflow of water from the containment sump back to the RWT. This could result in an unmonitored release of fission product gasses to the environment through the RWT vent.

Verifying both Component Cooling Heat Exchangers in service helps prevent a single component failure from resulting in total failure of the system. Aligning a CS pump for SI and securing the running HPSI pumps, in the event a CC pump is not available ensures the maintenance of core cooling in the event of a loss of component cooling, which would cause the eventual loss of the safety injection pumps. 2302

The EPG contains a step to secure one HPSI pump post-RAS with an alternate step to restart the HPSI pump if stop criteria are not maintained. The EOP contains steps to throttle HPSI flow to each header.

The intent of the EPG step is to reduce the total ECCS flow through the containment sump screens in order to reduce debris buildup on the screens. The EPG bases states that some plants may find it more beneficial to throttle both HPSI pumps post-RAS versus securing one HPSI. This is an acceptable alternate method of reducing flow through containment sump screens if plant staff has determined an overall beneficial effect. CCNPP has a relatively shallow sump when compared to the industry. Under worst case conditions only 2 feet of margin exists in NPSH calculations. With one or 2 HPSI pumps running, available NPSH requires that HPSI flow be throttled. When 2 HPSI pumps are running throttled at 1000 gpm with 2 CS pumps at 1350 gpm each, total flow through the containment sump would be 3700 gpm. By securing one HPSI pump, only a relatively small improvement to 3300 gpm is achieved by throttling the HPSI pump to 600 gpm. This results in a larger HPSI pump flow of 600 gpm for the running pump vs. 500 gpm per pump with 2 HPSI pumps running. This increased HPSI pump flow rate increases the required NPSH by 5 feet. Though accounted for in the worst case condition, it represents an enormous loss of operating margin.

Restricting total HPSI pump flow to 1000 GPM if two or three HPSI Pumps are operating minimizes the possibility of HPSI pump cavitation. The 1000 GPM flow is based on having all three pumps running or having the 13 (23) HPSI pump fail. This lineup would cause both 11 and 12 (21 and 22) HPSI pumps to use the same suction piping. This raised flow along with the elevated temperatures in the containment sump increases the possibility of HPSI pump cavitation, therefore the flow is reduced to less than twice the capacity of a single pump. It is important, however, to balance the flow of the HPSI pumps to approximately 250 GPM per header. If only one HPSI pump is running, maintaining a total flow of 600 GPM (approximately 150 GPM per header) minimizes the possibility of HPSI pump cavitation and at the same time, ensures sufficient flow to the core to ensure the core is adequately cooled. The 600 GPM limit is an upper and lower limit. The upper limit is based on HPSI pump cavitation. The lower limit is based on core cooling requirements. This lower limit takes into account decay heat loads, required flow to keep the core covered (386 GPM), spillage or the amount flowing out the break during a LOCA (150 GPM), and instrument uncertainties (64 GPM). 600 GPM is based on the 36 minute (RAS large break LOCA) heat load. As the heat load drops the minimum flow limit can be reduced as shown on Attachment (10). The requirement to equally throttle HPSI flow is based on maximizing flow through the core. Departures from equal flows would indicate either a closed flow path or a system leak, whereas the flow would be higher in the leg with the break. Throttling flow equally would provide a higher flow to the core prior to flowing out the break. (Reference: Action Value Basis Documents: EOP-12.01, 12.03, 12.05)

The EPG action steps when monitoring for loss of ECCS pump suction stops all CS pumps, observes HPSI performance, if performance does not improve it throttles HPSI flow to minimum required HPSI pump flow rate, if performance does not improve then it stops the HPSI pump, or gradually increases flow to achieve the maximum available. The EOP first throttles HPSI flow to minimum required HPSI pump flow rate, if HPSI or CS pump performance does not improve it stops all CS pumps, observes HPSI performance, if performance does not improve then it stops the HPSI pump.

Monitoring for adequate pump suction supply is performed upon RAS and is continuously applicable while in the recirculation mode. Pump cavitation signs are indicative of a loss of sump suction supply. Due to the difference in required NPSH, the HPSI pumps would be expected to cavitate before the CS pumps given a common cause from the sump suction supply. Due to a small margin between available and required NPSH early in the event when sump temperature is highest, HPSI flow is first throttled to the minimum allowed by Attachment (10). This action maintains all design functions. If this action does not correct the problem then another cause such as sump clogging beyond design may be occurring. Stopping CS pumps will significantly reduce sump flow, providing maximum available NPSH for the HPSI pump(s). Given that sump clogging beyond design has occurred, over time additional debris transported to the sump screens will result in a greater loss of available NPSH. The final failure mode for CCNPP pumps would be air ingestion due to the sump screens not being fully submerged. As DP rises across the sump screens, a waterfall effect is created inside the sump. Air ingestion would occur if the DP across the sump screens built up to greater than the sump screen height. DP is exponential with clogging and it is estimated that failure would occur rapidly once DP has surpassed half screen height. The purpose of stopping all CS pumps is to reduce the demand on the sump to a minimum, protect the remaining HPSI pump(s), and buy some time to implement EOP-8. Core Heat Removal via Inventory Control takes precedence over the Containment Safety Functions. The operator should notify the Plant Technical Support Center due to the loss of sump suction, an impending loss of recirculation capability, and transition to EOP-8. Since this event is beyond design bases, EOP-8 is implemented regardless of whether or not the loss of suction is believed to be total at this point or not. Once blockage starts, it is unlikely that it will improve on its own. The buildup will continue until the screens are totally blocked or the screens fail.

Commencing ECCS Pump Room cooling ensures cooling to the SI pumps to prevent pump damage from excessive heat.

Placing the ECCS pump room ventilation filters in service was added because of an NRC commitment in the Questions and Answer section of the FSAR. The rooms are not required to be ventilated, however, if they are then the charcoal filters must be placed in service. (Reference: P.S. Furio, BG&E Licensing Unit, letter to K.B. Umphrey dated February 15, 1989)

Adjusting saltwater flow to maintain SRW and Component Cooling temperatures provides for the additional cooling needed due to the additional heat loads during recirculation. A primary concern of exceeding the maximum design SRW temperature of 105°F is continued Diesel Generator operation. SW header pressure is checked to ensure adequate SW pump minimum flow. (Reference: Action Value Basis Documents: EOP-79.01, 80.01)

The charging pumps are secured by placing them in PULL TO LOCK if they are aligned to take suction from the RWT to prevent a loss of suction to the charging pumps. This is necessary due to the low level in the RWT and because the charging pumps automatic trip on low suction pressure is bypassed during a SIAS actuation.

Ensuring HPSI flow is at least 90 GPM verifies the HPSI Pump minimum flow is satisfied. This is necessary in order to avert HPSI pump damage. If minimum flow requirements are not met, and HPSI termination criteria has been met, the operator should turn off the charging pumps one at a time until the minimum flow requirements are met. If minimum flow requirements are still not met with all the charging pumps off, then HPSI pumps are secured, one pump at a time. HPSI pumps and the charging pumps should be left operating at all times, if the termination criteria are not satisfied. (Reference: Action Value Basis Document: EOP-12.01)

If minimum flow does not exist and the HPSI termination criteria are not satisfied, the HPSI pumps will probably be pumping against shutoff head. In this situation, the charging pumps are supplying the majority of the flow and should be left running to supply the necessary RCS makeup. If this condition is present, the operator should ensure adequate heat removal is occurring.

Step: IV.T. IF AN ELECTRICAL BUS HAS BEEN LOST, THEN RESTORE FROM LOSS OF POWER.

The EPG step to recover from a loss of offsite power is step 28. The EOP places the step after the equivalent for the EPG step 37.

The EPG step states when resources permit and is continuously applicable. The EOP step is continuously applicable and sequenced in the procedure such that resources are expected to be available.

The Loss Of Coolant Accident, Steam Generator Tube Rupture, Loss Of All Feedwater, and Excess Steam Demand Event Emergency Operating Procedures are designed to be able to recover from the identified event with a concurrent Loss Of Offsite Power or other power loss event (not including a station blackout). This step, along with steps taken in EOP-0, <u>Post-Trip Immediate Actions</u>, provide the necessary actions to restore the plant to a condition capable of responding to these events combined with a loss of power. This allows the use of Optimal Recovery Procedures instead of forcing the operator to implement the Functional Recovery Procedure as long as at least one Engineered Safety Features System bus remains energized. The actions necessary to restore power should continue until power is restored. When offsite power becomes available, electrical AC power is restored to the electrical distribution and station loads. This step provides a mechanism for restoring the 500KV switchyard, RCP bus power, non-vital plant loads, and backup power to vital plant loads should the diesel generators need to be secured. If offsite power is not available, the operator should continue efforts to restore power and align available diesel generators and/or the SMECO tie to supply additional power. Additional power greatly simplifies the plant shutdown. If additional sources are unavailable, DG load control will need to be monitored by the operator as equipment is re-energized to support the shutdown.

1./2. If either 11(21) or 14(24) 4KV Bus is deenergized the operator is directed to attempt to reenergize the bus by any method given. The first method listed is to place the designated DG on the associated bus. If the designated DG is not available, the 0C DG can be placed on 11, 14, 21 or 24 4KV Bus. First, the 0C DG is verified running. If a 4KV bus was deenergized at the beginning of the event the 0C DG would have been started in EOP-0. If not running, the operator is directed to perform a local emergency start per OI-21C. The local emergency start is used because, if the 0C DG is not running at this point, pneumatic prelube will most likely be required (pneumatic prelube is required if the 07 4KV Bus has been deenergized for greater than 30 minutes). If the 0C DG is prelubed and emergency started locally, all Control Room 0C DG controls remain operable. The SMECO tie should be aligned to a unit 4KV Bus which is not powered by a DG using OI-27E. The System Operator-Transmission System Operator is then contacted to determine when offsite power is expected.

3. This step directs the operator to restore power, per the attachment, to the various buses when offsite power is restored.

4. Switchyard auxiliaries are verified energized to ensure continued operation of the switchyard.

5. The 480 volt system is designed to function reliably and supply power during normal operation and under accident conditions. Four of the unit load centers (11/21A, 11/21B, 14/24A and 14/24B) and two motor control centers (MCC-104/204 and MCC-114/214) supply power to the engineered safety features. The engineered safety features electrical system incorporates the two-channel concept wherein independent electrical controls and power systems supply redundant 480 volt engineered safety features. The 480 volt engineered safety features electrical system meets the single failure criterion as defined in Section 4.2 of IEEE-279, and is designed as a Class 1E system.

   If the MCCs are tied during or subsequently a Loss of Coolant Accident or Main Steam Line Break occurred, the loads on the MCCs in a tied condition could exceed the MCC-114 (MCC-204) feeder breaker trip setpoint of 600 AMPS minus 10% or 540 AMPS, resulting in the loss of both trains of equipment powered from these buses. By shedding the designated loads, the calculated loads will not exceed 540 AMPS. It is assumed that the CR HVAC will not be energized if tying MCC-114 to 104 (MCC-204 to 214) due to the load center being deenergized, therefore load shed is not required for the MCC-104 (MCC-214) feeder breakers. (Reference: Rich Buttner to Robert K Bleacher, DMLS DE04344, dated May 11, 1998)

6. 1Y09 and 1Y10 (2Y09 and 2Y10) are checked to be energized since these buses supply power to the plant computers and data acquisition systems. The 208/120V Instrument AC system is designed to furnish power to all plant instruments other than those supplied from the DC and the vital AC systems.

7. During accident conditions accompanied by simultaneous loss of preferred power, the shutdown sequencer for the non-accident unit will start automatically to load sequentially the diesel generators. If the listed components are not working, then the appropriate AOP or OI should be performed concurrently with this procedure.

8. Upon completion of verifying the shutdown sequencer loads operating as required for plant shutdown, the second train DG may be running without cooling. Therefore to protect a DG from overheating in the case it is running without it's auxiliaries systems for cooling, the 1B, 2A or 2B DGs are secured. To prevent automatic restart, the DG must be secured by tripping the fuel racks. The fuel racks are tripped because if a DG is running with an auto-start signal present and is stopped via the Stop Pushbutton the DG will restart in 60 seconds.

9. If SIAS has not actuated, the operator is directed to check that at least one Instrument Air Compressor has started and to perform the appropriate OI if it has not.

   If SIAS (LOCI sequencer) has actuated, the same equipment with the exception of the Instrument Air Compressors will be energized. This is due to the fact that service water will be secured to the turbine building resulting in a loss of Instrument Air Compressors on high temperature. Therefore, if SIAS has actuated, the Instrument Air Compressors are not checked by this block step. In this case, the Instrument Air Compressors will be restored under the block step to restore auxiliaries.

10. Restoration of component cooling, if required, is done by first recording the highest RCP Controlled Bleed-off and lower seal temperatures. The Controlled Bleed-off temperatures are recorded since the seals of any RCP whose Controlled Bleed-off temperature has exceeded 250°F, must be rebuilt prior to restarting of the affected pump. This recording is necessary since Controlled Bleed-off

temperatures will lower when Component Cooling water is restored to containment, and there are no indications to determine if temperatures have exceeded the limit. The RCP restart step provides a more detailed explanation of this limit. The step directs that RCP lower seal temperatures must be less than 280°F or that Component Cooling be isolated to containment. This is done to prevent thermal shock to the RCP seals and RCP seal coolers resulting from the initiation of cooling water at elevated component temperatures. Component Cooling to containment will be reinitiated by throttling if necessary, in order to prevent this from occurring. (Reference: Commitment Resolution Document AIT 1F9400897 dated November 14, 1994; Action Value Basis Document: EOP-56.01)

11. The Component Cooling Heat Exchanger in service is verified to be supplied from an operating Saltwater Header. This is necessary to ensure the Saltwater pump and header started after a loss of power is aligned to the Component Cooling Heat Exchanger on service.

Step: IV.U. ENSURE AUXILIARY SYSTEM OPERATION.

The EOP contains a plant specific step to ensure proper operation of the electric systems, saltwater system, service water system, component cooling system and instrument air system. If any of the auxiliary systems are not operating properly, then restore the system per the appropriate AOP. The EPG does not contain this step.

The loss of auxiliary systems may occur before or during the event, but the extent of the loss may not cause any safety functions to be threatened. Providing actions to allow for the restoration of these systems ensures the safety functions are monitored while providing guidance for the system restoration in accordance with the appropriate recovery procedure.

Step: IV.V. COMMENCE THE ESFAS VERIFICATION CHECKLISTS.

The EOP contains a step to perform ESFAS verifications using checklists. The EPG does not contain this step.

This step verifies ESFAS actuated systems are functioning properly and automatic valve repositioning has occurred correctly. The use of the word verify directs the operator to take manual actions to align the affected system as indicated in the checklist if automatic action has not occurred. The operator should match the position of the handswitches to the checklist position unless otherwise specified. The operator should not align equipment that has been operated as a result of HPSI or LPSI throttling/termination criteria to that specified by the checklist. This step is placed late in the procedure so Core and RCS Heat Removal as well as Inventory and Pressure control are verified not to be threatened prior to diverting the operator's attention in the accomplishment of checklists. (Reference: SOER 94-01, Non-conservative Decisions and Equipment Performance Problems Result in a Reactor Scram, Two Safety Injections and Water-Solid Conditions.)

Step: IV.W. IF THE LEAK IS INSIDE CONTAINMENT,
THEN RESTORE THE CONTAINMENT ENVIRONMENT.

This block step provides steps in restoring containment environment to allow resetting of ESFAS actuation equipment. This step is consistent throughout the procedures whenever containment environment is challenged.

The EPG contains a step to provide containment radiation levels to the TSC, to evaluate the impact of potential environmental release and if containment radiation levels are high, to consider operating the Iodine Removal System. The EOP does not contain a step to provide containment radiation levels to the TSC, and contains a step to verify the Iodine Filter fans are running when addressing restoration of containment environment without requiring high containment radiation levels.

Containment radiation level assessment is performed via the Emergency Response Plan.

1. The containment iodine removal system is designed to collect within the containment the iodine released following a loss of coolant accident. Following a loss of coolant accident, a SIAS automatically starts three 50 percent capacity recirculation filter units, each with 20,000 cfm capacity. These units consist of activated charcoal filters preceded by high efficiency particulate air filters. A moisture separator is provided upstream of the particulate air filters to remove water droplets. An electric driven induced draft fan located at the end of the banks of filters pulls the containment atmosphere through these components and discharges vertically back into the containment. The operators should verify these fans have started and are operating to reduce containment iodine levels. The three containment charcoal filter units contain a total of 7300 lbs. of Barnebey-Cheney #727 coconut shell charcoal impregnated with 5 WT. % iodine compounds. Test conducted by the ORNL on Barnebey-Cheney #727 charcoal demonstrate that the installed charcoal absorbers will perform satisfactorily in removing both elemental and organic iodides for design conditions of flow, temperature and relative humidity. In these tests iodine removal efficiencies ranging between 90 to 99 percent were obtained. Filter efficiency fell toward the lower level as relative humidity approached 99 percent.

The EPG steps to secure containment spray are steps 12A and 12B. They are sequenced such that they may be performed prior to RAS. EPG step 12A verifies containment pressure less than design pressure, the required number of cooling fans are in operation, safety injection actuated and has proper flow. It then stops all but one CS pump and verifies containment pressure remains below design pressure. With a contingency action to restart the CS pump. EPG step 12B verifies pressure less than CSAS reset pressure, and spray is not required for containment cooling or iodine removal. It then resets CSAS, stops the CS pump, closes the spray header isolation and aligns the system for automatic CSAS operation. The EOP step is sequenced after the equivalent step 28/65. The EOP resets the CSAS signals, verifies all available containment air coolers in operation, and restores CSAS equipment. Then when containment pressure drops to less than the SIAS and CIS setpoint, it resets the SIAS and CIS signals, secures one containment spray pump, restores SIAS and CIS equipment, and when the plant technical support center recommends, secures the second containment spray pump.

The intent of the EPG step is to reduce or secure containment spray pumps as early as possible after it has been confirmed that they have performed their safety function. The objective is to reduce the demand on the RWT, delay the time to start of containment recirculation during small *breaks, reduce the flow rate to the sump when containment recirculation begins, and to reduce the pressure differential across the sump screens if there is a build up of debris. It then performs a controlled termination when containment spray is no longer needed, and states that prolonged operations of sprays into containment increases the probability of electrical grounds, shorts and other equipment malfunctions occurring. The bases for EPG step 12A states that each plant must consider the advantages and disadvantages as they apply to their specific design and incorporate this action if it is determined to be risk beneficial with respect to containment sump blockage. The intent of the EOP step is to secure wetting containment components when containment spray is no longer required. At CCNPP the containment spray pumps are started with a SIAS signal, thus to secure the containment spray pumps without overriding ESFAS signals, SIAS must be reset. EPG step 44/71, which resets safety signals when no longer needed, is continuously applicable, which permits the action to reset SIAS and CIS at this point in the EOP. Due to single failure criterion, if the operator manually secured a CS pump, the other pump is subject to subsequent failure. Until discovered and corrected, containment spray would not exist if a failure resulted in the loss of the remaining containment spray train. This would invalidate various evaluations/calculations of which environmental qualification is included. At CCNPP containment spray is needed until the Technical Support Center evaluates conditions and determines that environmental qualifications can be maintained. This step is consistent throughout the procedures whenever containment environment is challenged.*

2. If containment sprays have actuated and containment pressure is reduced below 4.0 PSIG, then CSAS can be reset. If RAS has actuated the miniflow valves to the RWT are shut. Prior to resetting CSAS the Containment Spray Header CV handswitches are verified in open to ensure a flow path exists for the running Containment Spray Pumps. (Reference: Action Value Basis Document: EOP-04.03)

   Containment Air Coolers are verified operating to aid in reducing containment temperature and pressure. This allows heat to be removed from the containment and minimizes the repressurization following securing of the containment spray pump(s).

   CSAS equipment listed in Attachment (3), <u>CSAS Verification Checklist</u>, is restored to the desired condition to complete CSAS resetting. CSAS must be realigned for automatic operation in case containment pressure again increases to the actuation setpoint.

3. This step provides actions to allow resetting of CIS and SIAS. When containment pressure has been lowered to below the containment pressure setpoint for CIS and SIAS of 2.8 PSIG, CIS and SIAS are reset. Note the pressurizer pressure signals must also be blocked in order to reset SIAS since pressurizer pressure will probably be below the SIAS actuation point of 1725 PSIA. SI pumps should continue to be operated though unless termination criteria have been met. Continued operation of the sprays after pressure and temperature can be maintained at or below an acceptable level increases the possibility of wetting electrical connectors which may result in electrical grounds, shorts and other malfunctions. The safety analysis for the LOCA shows containment pressure drops to the resetting point of CSAS, increases when recirculation starts, and eventually decreases below the resetting point again. One Containment Spray Pump is left operating in order to continue lowering containment pressure and temperature. Spray operation may be required for more than 100 days before temperature will remain below 120°F after securing the last pump. This ensures the containment temperature is reduced below 120°F within 30 days to

meet environmental qualification requirements. (Reference: Ian Sommerville, BGE Nuclear Engineering Unit, NEU 93-176, to W.J. Lippold, dated June 30, 1993; Ian Sommerville, BGE Nuclear Engineering Unit, NEU 94-021, to W.J. Lippold, dated July 28, 1994; Action Value Basis Document: EOP-04.02, 06.01)

At this point, equipment listed in the SIAS and CIS verification checklist may be restored to the desired condition.

4. The remaining Containment Spray Pump may be secured when it can be assured containment temperature will remain below 120°F. The Plant Technical Support Center must evaluate heat removal capability and decay heat before securing Containment Spray. (Reference: Ian Sommerville, BGE Nuclear Engineering Unit, NEU 94-021, to W.J. Lippold, dated July 28, 1994.)

Step: IV.X. IF RAS ACTUATED,
THEN REFILL RWT.

The EPG contains step 12A to lineup for RWT refill or alternate RCS injection. It then contains step 37B to refill the RWT. The EOP contains a single step to refill the RWT and notifies the Plant Technical Support Center to review ERPIP-611 for alternate methods for RWT refill and alternate RCS injection.

> *The EPG step 12A is intended to initiate early action to lineup to refill the RWT or lineup alternate sources for RCS injection bypassing the RWT, as a preemptive/precautionary move if sump recirculation capability should be subsequently lost. The EOP does not have an early step due to concerns of radiation levels when RAS occurs. Normal RWT refill can not be performed until SIAS has been reset. Any alternate methods to refill the RWT or inject to the RCS should be evaluated against existing event conditions by the Plant Technical Support Center, which will not be manned very early in the event.*

This block step provides steps to provide defense in depth for the containment sump associated with sump blockage. Starting RWT refill as early as possible after an RAS produces the greatest benefit. Therefore the lineup and refill should be started as soon as circumstances allow and resources are available because it may take considerable time to refill the RWT sufficiently to become a viable water source.

1. The operator should contact the Operational Support Center to check radiation levels are low enough to allow valve repositioning.

2. SIAS signals must be reset to allow normal makeup to the RWT.

3. The Plant Technical Support Center is notified to review ERPIP-611 for alternate methods to refill the RWT, and methods to inject directly to the RCS bypassing the RWT. Any action to inject additional inventory to the RCS will result in greater inventory than in design calculations. Possibly resulting in flooding equipment or instrumentation needed to control or mitigate the event. However the containment sump is a single piece of equipment without a redundant backup. This step provides defense in depth to ready personnel if the containment sump subsequently loses function.

Step: IV.Y. IF SIAS HAS ACTUATED AND HAS BEEN RESET,
THEN RESTORE AUXILIARIES.

The EPG step that resets safety signals when no longer needed is step 44/71. The EOP places the step before the equivalent for the EPG step 38/67.

The EPG steps are continuously applicable. SIAS must be reset and various auxiliaries restored before RCPs can be restarted. If SIAS has not been reset, this series of steps will be skipped over and the equivalent for EPG step 38/39 will be performed.

This block step provides steps necessary to restore Service Water and Instrument Air to operation. Service water is restored to the turbine building to allow an Instrument Air Compressor to be started which will allow control of other primary and secondary components. Instrument air is then restored to containment to allow control of the CVCS letdown, and other components inside of containment.

1. This block step assumes a SIAS has actuated causing Turbine Building SRW Isolation Valves to shut, removing cooling water to the instrument air compressors. The operator is instructed to verify an air supply from the other unit is operating, isolate instrument air from plant air and cross connect instrument air from the other unit's plant air. Service water control valves can then be opened to restore Service Water to the turbine building.

2. Once Service Water is restored to the turbine building, an instrument air compressor can be restored to service. This is assuming the compressors were tripped on high temperature when SIAS actuated and isolated cooling water to the compressors. The operator should open the Service Water supply valve to supply cooling water to the instrument air compressor to clear the high temperature alarm. This valve will receive an open signal to maintain the valve open when a start signal is generated. At least one air compressor is then started.

3. After an instrument air compressor is returned to service, instrument air is resupplied to containment. This is accomplished by opening the containment motor operated isolation valve. The Containment Instrument Air Supply control valve is then opened by momentarily opening its override valve.

Step: IV.Z. IF COMPONENT COOLING HAS BEEN SECURED TO CONTAINMENT, THEN RESTORE FLOW.

The EPG step that resets safety signals when no longer needed is step 44/71. The EOP places the step before the equivalent for the EPG step 38/67, following the EOP step to restore auxiliaries.

The EPG step is continuously applicable. For consistency, steps for restoration of equipment is grouped together throughout the EOPs.

Restoration of component cooling is performed by recording RCP Controlled Bleed-off and lower seal temperatures, verifying CIS has been reset and reinitiating flow to containment.

1. The operator first records the highest RCP Controlled Bleed-off and lower seal temperatures. The Controlled Bleed-off temperatures are recorded since the seals of any RCP whose Controlled Bleed-off temperature has exceeded 250°F, must be rebuilt prior to restarting of the affected pump. This record is necessary since Controlled Bleed-off temperatures will lower when Component Cooling water is restored to containment, and there are no indications to determine if temperatures have exceeded the limit. The RCP restart step provides a more detailed explanation of this limit.

2. The operator must verify CIS has been reset in order to open the Component Cooling Containment Isolation Valves, which receive a shut command on CIS.

3/4. This step allows the operator to restore Component Cooling flow to containment by simply opening the containment isolation valves as long as RCP lower seal temperatures have not exceeded 280°F. If RCP lower seal temperatures have exceeded 280°F, flow must be restored by throttling the manual isolation valve. This is done to prevent thermal shock to the RCP seals and seal coolers resulting from the initiation of cooling water at elevated component temperatures. The step to restore Component Cooling to containment has been modified so it is sequenced after determining RCP lower seal temperatures have not exceeded 280°F so Component Cooling water is not restored to a pump whose seals have exceeded 280°F without throttling flow. (Reference: Commitment Resolution Document AIT 1F9400897 dated November 14, 1994; Action Value Basis Document: EOP-56.01).

Step: IV.AA. RESTORE LETDOWN FLOW.

The EPG step which restores letdown is step 52. The EOP places the step before the equivalent for the EPG step 38/67, following the EOP step to restore component cooling to the containment.

The EPG step is continuously applicable. For consistency, steps for restoration of equipment is grouped together throughout the EOPs.

This block step provides actions required to place letdown in service to aid in RCS pressure and inventory control. The operator should verify that reinitiating letdown will not reinitiate the LOCA and that RCS inventory control has been established. Then the operator should verify a charging flow path exists a charging pump and a component cooling pump is operating in order to return letdown to the RCS as needed. To return letdown to service, the operator should first verify the Pressurizer level controller in Auto Remote. This automatically establishes a level setpoint as specified by the reactor regulating signal. At zero power, this will be 160 inches. The Letdown Pressure Regulator Controller is then placed in manual with a 20% output to prevent flashing downstream of the valve when flow is restored. This is also done to prevent the Letdown Relief Valve from lifting due to the slow action of the Pressure Control Valves. The operator then places the Ion Exchanger Bypass Valve to bypass to prevent shocking the resin until system parameters have stabilized so resin damage will not occur. The Letdown Throttle Valve Controller is then shifted to manual and adjusted to 20% to allow a controlled reinitiation of flow. The Letdown Isolation Valves are then opened and the setpoint on the Letdown Pressure Regulator Controller 1(2)-PIC-201 is adjusted so it is above the saturation pressure for the letdown outlet temperature of the Regenerative Heat Exchanger to prevent flashing at the letdown control valve. It is then placed in AUTO. The Letdown Throttle Valve Controller is then adjusted to slowly restore letdown flow to minimize the transient placed on the system, and is subsequently shifted to automatic. The Letdown Temperature Controller is operated to maintain Letdown Heat Exchanger letdown outlet temperature less than 120°F, and the pressurizer level is verified to be trending to 160 inches. If level is not trending to 160 inches, the zero power setpoint, the operator is directed to shift the Pressurizer Level Controller to Auto Local and adjust the setpoint to 160 inches. With pressurizer pressure less than 1000 PSIA, to obtain the desired flow rate to maintain pressurizer level, both Backpressure Regulating valves and Letdown Control Valves may be required in service. This requirement is a normal evolution when performing a plant cooldown. (Reference: Action Value Basis Documents: EOP-19.04, 22.24, 47.01).

Step: IV.AB. IF THE RCS IS WATER SOLID,
THEN DRAW A BUBBLE IN THE RCS.

Once letdown has been restored to service, if the RCS is water solid, the option to restore a bubble in the RCS is presented. Water solid operations may continue as required so long as subcooling is maintained between 30 and 140°F. As long as the operators have established control of RCS temperature and inventory, there is no urgency to re-establish a bubble in the pressurizer. The goal of this step is to draw a bubble in the pressurizer or the Reactor Vessel head if the decision is made to do so. Prior to drawing a bubble in the pressurizer, it is assumed that the LOCA has been isolated and that the pressurizer is intact. Depending on plant conditions and event recovery strategy, the operator may choose to not intentionally draw a bubble, and proceed with cooldown with the existing conditions. The activities necessary to establish a bubble in the pressurizer are: 1) heating the water in the pressurizer to saturation temperature for the pressure desired; 2) lowering the RCS pressure to the saturated conditions by removing inventory via letdown flow and/or reducing inventory volume via RCS heat removal: 3) continuing to remove inventory or reduce inventory volume in the RCS in order to lower water level in the pressurizer to an acceptable reading.

The most effective method of drawing a bubble is to initiate a cooldown. Commencing a cooldown is usually appropriate whether it is desired to draw a bubble or not. A bubble will ultimately form in the pressurizer, RV head, or SG U-tubes by simply cooling down and allowing the RCS to depressurize, without any other action. A bubble will form quicker in the pressurizer or RV head if letdown can be established and maximized. The probability of a bubble forming in the pressurizer is increased if the pressurizer heaters are energized. Once heat removal is established, the cooldown progresses slowly and the plant is easily controlled. It will take a considerable amount of time to draw a bubble. A bubble may form in the RV head before forming in the pressurizer. This is not a problem as long as it does not impede natural circulation flow. A bubble will form with or without RCPs operating. It will form quicker with a RCP running, due to the increased heat removal. There is no benefit in holding RCS temperature and pressure constant while making a decision on whether or not to draw a bubble.

The pressurizer heaters are energized to increase the likelihood that the bubble will form in the pressurizer.

Efforts should be made to minimize the probability of void formation in the S/G U-tubes. Drawing a bubble in the tubes of one steam generator will aid in RCS pressure control but will not provide a method of monitoring RCS inventory. The purpose of this step is to avoid operating without the ability to monitor RCS inventory. Therefore, direction is given to maintain S/G pressure less than RCS pressure. By doing so the S/G steam space, and consequently the top portion of the U-tubes, will be the coolest part of the RCS, therefore voids should not form in the U-tubes. If an RCP is in operation, void accumulation in the top of the U-tubes will not occur. Pressurizer pressure should be reduced by letdown flow greater than a combination of charging and HPSI flow. HPSI throttle/termination criteria must be met prior to throttling HPSI or charging flow. RCS cooldown should be initiated within Tech. Spec. limits. (Reference: Action Value Basis Document: EOP-24.02)

If a bubble forms in the pressurizer, HPSI, charging and letdown flows should be adjusted to restore and maintain the pressurizer level within the normal control band. (Reference: SOER 94-01, Non-conservative Decisions and Equipment Performance Problems Result in a Reactor Scram, Two Safety Injections and Water-Solid Conditions, Action Value Basis Documents: EOP-19.01, 19.06)

If a bubble forms in the RV head, Reactor Vessel level indication must be monitored to maintain level above the top of the hot leg for proper inventory control.

Step: IV.AC. RESTORE FORCED CIRCULATION.

The EPG steps to restart RCPs are steps 31 and 32. The EOP places the step before the equivalent for the EPG step 38.

> *The EPG step and the EOP steps are continuously applicable. The EOP step is placed such that all steps to ensure resources are available to restart RCPs have been completed prior to the RCP restart step.*

The plant conditions should be carefully assessed before any RCPs are restarted. The need for forced circulation operation should be balanced against the risk of damage to the RCP seals. Because of the complexity of starting RCPs, forced circulation is left as an option. If the existing natural circulation is providing satisfactory RCS and core heat removal, a transfer to forced circulation operation may not be necessary. This would be particularly true if the RCS had already been cooled and depressurized to shutdown cooling entry conditions. If the RCS pressure and temperatures are closer to hot standby conditions, it may be desirable to restart the RCPs in order to allow a normal forced circulation cooldown. One of the biggest factors against continuous use of natural circulation is the limited steam flow capability of the atmospheric dump valves at low S/G pressures. If desired, the operation of two RCPs (in the same loop) may be attempted if RCP restart criteria are met. This will provide continued forced circulation of coolant through the core, provide cooling of the RV head region, condense RCS steam voids, and remove non-condensable gases from the S/G bundles. If the cooldown is performed using natural circulation, the time until shutdown cooling entry conditions are reached will be extended and, depending on the amount of makeup water available, RCPs may be needed to hasten entry into shutdown cooling.

The EOP contains a step to evaluate the need and desirability of restarting RCPs and specifies that if RCP operation is not desired to skip RCP restart steps. The EPG does not contain this step.

> *The EPG step simply states if RCP restart is desirable. The EOP specifies adequacy of RCS and Core Heat Removal using natural circulation, existing RCS pressure and temperatures and RCP Control Bleed-off temperatures as criteria to consider to determine if RCP restart is desirable. Step format then requires a specific step to skip over restart steps.*

1/2. The need for operation of the RCPs should be evaluated based on the adequacy of the RCS and core heat removal under the existing natural circulation conditions, the existing RCS pressure and temperatures, and the RCP Controlled Bleed-off temperatures. If the existing natural circulation is providing satisfactory RCS and core heat removal, a transfer to forced circulation operation may not be necessary. This would be particularly true if the RCS had already been cooled and depressurized to SDC entry conditions. If the RCS pressure and temperatures are closer to hot standby conditions, it may be desirable to restart the RCPs in order to allow as close to normal as possible, forced circulation cooldown. Consideration should also be given to the RCP Controlled Bleed-off temperatures. If any Controlled Bleed-off temperature has exceeded 250°F, the affected pumps' seals must be rebuilt before that RCP can be operated.

The EOP contains a plant specific step to skip restart of the RCPs if temperature dictates LTOP restrictions. The EPG contains a step to verify the RCS conditions are within the RCP start limits of plant technical specifications.

3. If T_{COLD} is less than 369°F (306°F), RCP restart is not allowed by the EOPs. This is due to the restrictions placed on restarting RCPs below these temperatures. Restarting RCPs is also not allowed due to the fact that the plant is near to establishing shutdown cooling entry conditions. If temperatures are below these limits, then RCPs should not be restarted and the operator should proceed to the next block step. (Reference: Action Value Basis Documents: EOP-24.05, 24.22).

The EOP contains a step to megger the RCP motors if they have been exposed to excessive moisture. The EPG does not contain this step.

4. During post-accident conditions, the containment volume can be high in moisture. These conditions can adversely affect electrical equipment within the containment. The wetting of equipment can result in grounds and electrical shorts. Under these conditions, the RCPs should be meggered prior to operation to ensure the moisture has not affected the RCPs' motors or electrical power supply.

5. RCP Controlled Bleed-off temperatures are checked to ensure they have not exceeded 250°F. The operator should check present temperatures and those recorded when restoring component cooling flow. Controlled Bleed-off temperatures are checked due to the adverse effects on the nonmetallic components that results from increased temperatures. Temperature effects on the nonmetallic components consist of hardening and embrittlement of the nonmetallic components (O-rings) of the RCP seal cartridge. From information currently available, the severity of this process is proportional to the length of time and magnitude of the temperature the seal is exposed to. In a TELCOM with Sulzer-Bingham, Don Spencer maintained that a temperature of greater than 250°F will require depressurization and seal rebuilding prior to pump restart. Under no condition would Sulzer-Bingham assume responsibility for seal performance if temperature has exceeded 250°F. Due to this degradation, the affected RCPs should not be restarted until the affected seal can be rebuilt. (Reference: TELCOM between C. Drumgoole, PD&MAU, R.A. Gambill, PMU, and Don Spencer of Sulzer-Bingham on July 6, 1990; Action Value Basis Document: EOP-54.02)

6. The RCP Controlled Bleed-off temperatures must be lower than 200°F prior to restarting RCPs. This step verifies RCP Controlled Bleed-off temperatures are less than 200°F or are lowering. If the operator is unable to reduce RCP Controlled Bleed-off temperature below 200°F, the affected RCP can not be restarted. The 200°F is the upper operating limit allowed by Sulzer-Bingham. (Reference: Action Value Basis Document: EOP-54.01)

7. Pressurizer level is raised to a band which is high enough to allow RCP restart. The lower bound of 155 inches provides sufficient volume of water to compensate for loop shrinkage and/or the collapse of any voids that may have formed in the RV head. Should significant voids exist, it is expected that pressurizer heaters would be uncovered, but void collapse is not expected to drain the pressurizer. It is important to note the procedure specifically does not say the RCPs must be secured due to pressurizer level changes. Once the pumps are restarted, their operating curves provide the criteria for further operating decisions. (Reference: Action Value Basis Documents: EOP-19.01, 19.13)

8. If RCP restart is to be attempted, then two RCPs in the same loop should be selected for operation, and RCP restart criteria must be verified to be satisfied. These restart criteria consist of the following considerations.

- Electrical power must be available to the RCP from one of the 13KV service buses. Also to satisfy the starting interlocks, component cooling water flow and oil lift pump pressure switches must be energized. MCC-115(215) supplies power to all four component cooling water flow switches and 12A(22A)/12B(22B) oil lift pumps. MCC-105(205) supplies power to 11A(21A)/11B(21B) oil lift pumps.

- The 13KV bus voltages must be less than 14.8KV, to prevent RCP motor overheating. The design voltage range is 11.88-14.5KV. Upon restart of the RCP the voltage is expected to be reduced to within the normal range. However the additional range is not expected to cause problems based upon the margin built into the design of the motors. (Reference: D.L. Glady BGE Electrical Engineering memo to E.D. Hemmila dated September 26, 1994; Action Value Basis Document: EOP-78.01)

- 4KV Bus voltages are checked to be greater than 4100 volts to ensure that when an RCP is started that the 4KV Bus voltages do not lower such that the degraded voltage relays actuate. (Reference: Action Value Basis Document: EOP-31.01)

- RCPs Controlled Bleed-off temperatures are less than 200°F. If the operator is unable to reduce RCP Controlled Bleed-off temperatures below 200°F, the affected RCP can not be restarted. 200°F is the upper operating limit allowed by Sulzer-Bingham. (Reference: Action Value Basis Document: EOP-54.01)

- Subcooling of 30°F ensures subcooled water is contained in the RCS loops and reactor vessel, with the exception of the head area. Having voids does not prevent a RCP restart. A subcooled condition, taken in conjunction with the minimum pressurizer level, indicates adequate inventory control has been established to allow RCP restart. The 30°F limit is consistent with the general subcooling limit and therefore aids procedural consistency efforts and is easier for operators to remember. (Reference: Action Value Basis Document: EOP-23.01)

- At least one S/G must be available for removing heat from the RCS. A steam generator is available for heat removal if: 1) S/G level is greater than (-)170 inches, 2) capable of being supplied with feedwater, and 3) is capable of being steamed. A S/G must be available for heat removal in order to remove the heat added from RCP operation. (Reference: Action Value Basis Document: EOP-27.10)
- Pressurizer level must be above 155 inches and not lowering to ensure that RCS inventory is stabilized and controllable. (Reference: Action Value Basis Documents: EOP-19.13)

- T_{COLD} must be less than 525°F to prevent lifting a S/G safety. When RCPs are restarted, simulator exercises have shown a pressure increase in the S/Gs attributable to an increase in T_{COLD} of about 10°F. If T_{COLD} were at 535°F, a 10°F increase would place T_{COLD} at 545°F which corresponds to a S/G pressure greater than the first S/G safety valve setpoint. (Reference: Action Value Basis Document: EOP-24.12)

- The RCS temperature and pressure are verified to be greater than the minimum operating limit curves of Attachment (1). This ensures NPSH requirements for the pumps are satisfied prior to starting a RCP. These curves govern continued RCP operation following pump restart. RCS pressure may be less than the RCP operating curve for a single RCP contained in OI-1A as long as the second RCP is started within five minutes. The limits for the targeted pump configuration should be satisfied prior to starting any RCP.

9. Restarting RCPs will ensure continued forced circulation of coolant through the core, cooling of the RV head region, condense RCS steam voids, and remove non-condensable gases from the S/G tube bundle. Furthermore, this action enhances the strategy to obtain an uncomplicated cooldown whenever possible during the recovery. However, only two reactor coolant pumps should be operated to minimize heat input to the RCS. The operator is directed to restart two RCPs in the same loop since the operating curves for pumps operating in opposite loops are more restrictive. Upon restarting two RCPs in the same loop, pressurizer level and pressure may decrease due to loop shrinkage and/or steam void condensation. It is possible this action will drain the pressurizer and/or initiate a SIAS if pressurizer pressure is not blocked. Steam voids present in the Reactor vessel will condense upon restarting RCPs. Reactor Vessel level indication should be monitored for the trending of reactor vessel liquid level. This trending information may be correlated to pressurizer level decrease. RCP operation with a drained pressurizer may continue provided NPSH criteria can be maintained and RCP cavitation does not occur.

The EPG contains a step to verify single phase natural circulation has been established for the preceeding 20 minutes in the loop selected for RCP restart. The EOP step specifies the loop with an operating S/G and does not have a time limit.

The EPG step specifies a time that flow has been established in the loop selected for RCP restart to ensure that a dilute (unborated) pocket is not introduced to the core when the RCP is started. Decay heat is being removed from the RCS during this entire procedure. Therefore, the loop with an operating S/G defined in this step will be in a loop that has not stagnated such that a dilute pocket could have formed.

Stagnation in an RCS loop under natural circulation conditions is possible whenever the two S/Gs are removing heat at different rates. The amount of temperature difference between S/Gs required to stagnate flow varies with decay heat level but generally the following thumb rule can be applied. The differential temperature required between S/Gs to start stagnating flow in a loop is 25° to 50°F. The loop containing the hotter S/G will be the loop to stagnate. Consequently, the procedure reference to a "loop with an operating S/G" can be defined as the loop containing the S/G with proper steaming and feedwater control. The first pump started is in the loop with the S/G available for heat removal for the following reasons:

- This loop will have forward flow already; starting the first RCP in this loop preserves the forward flow direction associated with natural circulation heat removal.

- RCS loop voids, if present, are more likely to be in the hotter stagnant loop, hence there is less risk of voids reaching the first RCP started if that RCP is in the cooler loop.

- Cold leg temperature in this loop is not expected to change upon starting an RCP in that loop. Hence, the operator's attention to possible NPSH violation as pressure falls after RCP restart can be primarily directed to the pressure drop.

- The loop has not stagnated, which prevents the formation of a dilute (unborated) pocket. Starting an RCP in an active loop ensures mixing of any dilute pockets prior to introduction to the core. Under some LOCA events there is a span of time during which steam generated in the core may have condensed in the steam generator tubes. The condensate formed from this steam is largely devoid of dissolved boric acid. A core reactivity problem may occur if unborated condensate, which has accumulated in the cold leg side of the RCS, returns to the reactor core without sufficient mixing with the highly borated water in the RCS.

A minimum set of actions required to satisfy the pump's starting interlocks are specified. These actions are not as complete as the OI because the intent of the EOP is to provide as concise and simple a set of actions as possible.

10. Voids may have formed during the event in the reactor vessel head. Starting the RCP will cause the voids to collapse or be swept out causing pressurizer level to drop. Charging pumps should be operated to restore and maintain pressurizer level to between 101 and 180 inches. If HPSI pumps are operating, continue their operation until termination criteria are met. This action will ensure pressurizer heaters remain covered or the pressurizer is subsequently refilled to recover the heaters. (Reference: Action Value Basis Documents: EOP-19.01, 19.06)

11. Monitoring RCP seal parameters was included to ensure proper seal performance following the temperature transients they were exposed to while restarting the RCPs. The seal temperatures and pressures should be checked to ensure normal values are observable.

12. The operator should allow temperatures to stabilize in the opposite loop due to possible loop stagnation as discussed above, and then start the second RCP.

The EPG states to start the second RCP in the opposite loop. The EOP states to start the second RCP in the same loop.

13. The second RCP should be started similarly to the first. The NPSH requirements should be verified to be satisfied, and then the pump should be started using the procedure detailed above. The operator is directed to restart two RCPs in the same loop since the operating curves for pumps operating in opposite loops are more restrictive. Following restart, RCP seal parameters should be monitored to ensure proper performance.

Main pressurizer spray is not restored since insufficient spray flow is available during conditions where two pumps are started in one loop to provide satisfactory pressure control.

Step: IV.AD. PERFORM LOW TEMPERATURE ACTIONS.

This block step provides the steps necessary to establish MPT protection as required by Tech. Specs. to prevent a Low Temperature Over Pressure (LTOP) event, and additional actions necessary during low temperature conditions.

The EOP contains a step to secure Steam Generator Feed Pumps and Condensate Booster Pumps if high feedwater pressure is causing level control problems. The EPG does not contain this step.

1. The Steam Generator Feed Pumps and the Condensate Booster Pumps are high head pumps. As Steam Generator pressures decreases during the cooldown, the differential pressure across the feed regulating valves increases. This may cause difficulty with level control. This step permits the operator to secure the pumps, which is part of a normal cooldown.

2.(3). Technical Specifications require two power operated relief valves with a lift setpoint below the tech. spec. curve when not on shutdown cooling, be available, that a single power operated relief valve with a lift setpoint below the tech. spec. curve when not on shutdown cooling and a RCS vent path greater than or equal to 1.3 square inches be available, or that a RCS vent larger than 2.6 square inches be established anytime the temperature in one or more RCS cold legs is less than 365°F (301°F). Reducing the PORVs open setpoint protects against subjecting the RCS pressure boundary to low temperature brittle fracture. Placing the PORVs in the Variable MPT Enable mode reduces the setpoint of the PORVs from 2400 to a value below the curve. Placing the PORV Override Switches in Auto allows the "lock-in circuit" to maintain the PORVs energized and open if the open setpoint is exceeded. (Reference: Action Value Basis Documents: EOP-22.10, 22.27, 24.04, 24.05, 24.21, 24.22)

3.(2). Technical Specifications for the P/T limits assume that no more than 2 RCPs are in operation during a cooldown when RCS temperature is less than 350°F. (Reference: Action Value Basis Document: EOP-24.36)

The EOP contains a step to verify Cavity Cooling and CEDM cooling fans are running and a step to isolate the AFW system if it is not being used to feed the S/Gs. The EPG does not contain these steps.

4. The Cavity Cooling and CEDM cooling Fans are verified to be running. Although these fans would normally be secured at this point in a cooldown, due to the event that has occurred, the fans are left running to provide two desirable benefits. They aid in cooling of the reactor vessel which may help collapse any voids which may have developed during the event, and they aid in mixing of the air within the containment which may help in dispersing pockets of high hydrogen concentration. The SITs are isolated to prevent the nitrogen cover gas from being discharged into the RCS when RCS pressure is reduced below the SITs pressure during a controlled cooldown. If they have discharged, the SITs are isolated to prevent any additional nitrogen from expanding into the RCS to limit the non-condensable gasses which could accumulate in areas of the RCS which could inhibit heat removal. The last action is to isolate the AFW system if it is not being used to feed S/Gs since it is not required at low temperatures. (Reference: Action Value Basis Documents: EOP-22.11, 24.03).

Step: IV.AE. COMMENCE CORE FLUSH.

Simultaneous hot and cold leg injection is used for both small break and large break LOCAs at 8 to 11 hours after the start of the LOCA. In this mode, the HPSI pump discharge lines are realigned so that the total injection is divided equally between the hot and cold legs. Simultaneous injection into the hot and cold legs is used as the mechanism to prevent the precipitation of boric acid in the reactor vessel following a break that is too large to allow the RCS to refill. Boric acid precipitation is caused by long-term boil-off of coolant injection after a LOCA. The water boils off to remove decay heat, concentrating the acid within the reactor vessel. Eventually, the acid reaches its solubility limit, and will begin to precipitate. This precipitation can block coolant flow, and may cause additional core damage. For example, precipitation on the fuel alignment plate would reduce coolant flow area and flow rate, which leads to higher core temperatures. Injection to both sides of the reactor vessel ensures that fluid from the reactor vessel (where the boric acid is being concentrated) flows out the break regardless of the break location and is replenished with a dilute solution of borated water from the other side of the reactor vessel. If this action is taken too early the fluid injected into the hot leg may be entrained in the steam being released from the core and hence possibly diverted from reaching the reactor vessel. After a few hours, the decay heat has dropped sufficiently so that there is insufficient steam velocity to entrain the fluid being injected to the hot leg. The action is taken no longer than 11 hours after the LOCA in order to ensure that the buildup of boric acid is terminated well before the potential for boric acid precipitation occurs. Simultaneous hot and cold leg injection is not required for breaks which are small enough to allow subcooling to be regained because the buildup of boric acid is terminated when the RCS is refilled. Once the RCS is refilled, the boric acid is dispersed throughout the RCS via natural circulation. Therefore, if the RCS is filled, core flush is not required. If the RCS is not filled, core flush must be commenced between 8 and 11 hours following the event. If entry into shutdown cooling is expected before the 11 hour limit, and the criteria for entering normal shutdown cooling can be met, then the realignment to hot and cold leg injection is unnecessary. (Reference: J.F. Williams, BG&E Nuclear Engineering Unit, Letter to POSRC, NEU 90-271, dated April 9, 1990; Action Value Basis Documents: EOP-19.09, 19.10, 23.01)

1. The most preferred method of establishing hot leg injection is to line up 11 or 12 (21 or 22) HPSI pumps to inject water into the pressurizer via the auxiliary spray line. Pressurizer injection is the preferred method due to the pressure restriction on the shutdown cooling piping and the use of the LPSI Pump. (Reference: Action Value Basis Document: EOP-12.04)

   If pressurizer injection is not available or can not be maintained, the hot leg injection using a LPSI Pump is lined up via the shutdown cooling header return isolation valve. The RCS pressure limit is based on not overpressurizing the SDC Return Header to the LPSI pump suction. The 75 PSID limit is based on the ability of the LPSI pumps to supply the required flow of 150 GPM. (Reference: Action Value Basis Documents: EOP-12.04, 22.16, 22.17, 22.19)

   The next preferred method is to use the pressurizer injection with only one HPSI pump. This method divides the cold leg injection flow from the pressurizer injection flow. This method is available only for extreme situations. Because the total flow from one HPSI pump is used for both cold leg injection and pressurizer injection, the cold leg injection flow must be throttled to maximize the pressurizer injection flow. Since the pressurizer Injection flow, for this method, may not be adequate to prevent boric acid precipitation, one of the first methods should be implemented as soon as one is available. (Reference: Action Value Basis Document: EOP-12.02)

If Component Cooling has been lost, then the HPSI and LPSI pumps are unavailable and Cold Leg Injection is being performed with the Containment Spray Pumps. This flowpath ensures that sufficient flow is delivered to provide adequate cooling and in the case of a Cold Leg Break that adequate flow is delivered to the Hot Leg to prevent Boric Acid Precipitation. The RCS pressure limit is based on not overpressurizing the SDC Return Header to the Containment Spray pump suction. The 75 PSID limit is based on the ability of the Containment Spray pump to supply the required flow. The lowest mark on FI-332 is 600 GPM, therefore the flowrate of 600 GPM is specified without a range to achieve adequate simultaneous flows to the Cold Leg and the Hot Leg while allowing uncertainty on FI-332. (Reference: M.T. Finley, BG&E Nuclear Engineering Unit, NEU 94-155, memo to C.J. Andrews, PD&MAU, dated May 20, 1994; Action Value Basis Documents: EOP-14.01, 22.16, 22.17, 22.19)

The flowrate required for pressurizer and hot leg injection (150 GPM) ensures that makeup is available to the core for core boil-off, and provides a net flushing flowrate that will prevent boric acid precipitation. (Reference: M.T. Finley, BG&E Nuclear Engineering Unit, memo to R.J. Deatly, NEU 92-214, dated June 1, 1992)

2. When pressurizer injection or hot leg injection is in progress, the operator should balance the flow through each of the HPSI headers to minimize the amount of liquid lost through the break and maximize the amount of water reaching the core. Since the RCS has not been refilled, 11 and 13 (21 and 23) HPSI pumps should have already been operating. Minimum flow requirements must be maintained in order to ensure decay heat is being removed from the core. The operator should verify that the minimum flow requirement of Attachment (10) are maintained. Furthermore, the operator should ensure that CET temperatures remain constant or lowering. Rising CET temperatures indicate that core heat removal is being threatened.

Step: IV.AF. COMMENCE SHUTDOWN COOLING

For certain sized breaks (small breaks), entry into shutdown cooling may be possible and can be initiated when certain plant conditions exist. When these criteria are established, Shutdown Cooling should be initiated per OI-3B, Shutdown Cooling. In order to use this method, pressurizer level must be greater than 101 inches and RCS subcooling must be greater than 30°F based on CET temperatures. These two conditions ensure RCS pressure and inventory control has been established. This activity places the plant in an operational mode where a complete cooldown and depressurization of the plant can take place. (Reference: Action Value Basis Documents: EOP-19.01, 19.06, 22.16, 23.01, 24.30).

Prior to the initiation of shutdown cooling, the operator should contact the Operational Support Center to check radiation levels are low enough to allow valve repositioning. Once it can be verified that valves can be repositioned safely, the operator is directed to line up and start shutdown cooling per OI-3B, Shutdown Cooling.

If the conditions cannot be met, then a modified shutdown cooling lineup using the SIS aligned for cold leg injection should be performed. The requirements for this modified lineup includes wide range containment water level of at least 28 inches indicated. This indicated water level will ensure the NPSH requirements for any SI Pumps and CS Pumps are met prior to initiating shutdown cooling. In order to use this lineup, CET temperatures must also be less than the 300°F shutdown cooling system limit, and the differential pressure between the RCS and containment must be less than 160 PSID due to LPSI pump head limitations. The information is required to be recorded for the transient log entry. The lineup consists of aligning a LPSI pump to take suction from the containment sump and inject into the RCS with part of the flow passing via the shutdown cooling heat exchangers. The RCS temperature is then controlled by regulating the amount of flow allowed to pass through the shutdown cooling heat exchangers and thus the amount of heat removed by the heat exchangers. The 3000 GPM flow rate established when one LPSI Pump is operating is derived from the Tech. Spec. requirement that a shutdown cooling loop be in operation and circulating reactor coolant at a flow rate of greater than or equal to 3000 GPM. This requirement is based on ensuring sufficient cooling capacity is available to remove decay heat and maintain the water in the reactor pressure vessel below 140°F and to provide sufficient coolant circulation through the reactor core to minimize the effects of a boron dilution incident and prevent boron stratification. If the desired RCS cooldown rate can not be maintained with one LPSI pump, a second LPSI pump is started and the total flow is adjusted to 6000 GPM. (Reference: A.S. Drake memo to D.E.Lenker ME920237.052 dated Feb.27, 1992; Action Value Basis Documents: EOP-14.02, 14.03, 22.20, 24.02, 24.19, 24.24,24.30, 43.01, 68.01)

Step: IV.AG. SECURE CORE FLUSH FLOWPATH.

The EOP contains a step to secure core flush. The EPG does not contain this step.

The EPG exits at shutdown cooling. CCNPP does not have a procedure to secure core flush outside the EOP that could be exited to.

This block step provides the actions to terminate core flush once CET temperatures have been reduced to less than 200°F. Below 200°F, water in the RCS will no longer be flashing to steam since the temperature is below the boiling point for atmospheric pressure. Therefore, the buildup of boric acid within the reactor vessel will no longer be occurring and core flush may be terminated. (Reference: Action Value Basis Document: EOP-12.01, 24.14)

Step: IV.AH. IMPLEMENT THE APPROPRIATE PROCEDURE

The EPG contains a single set of safety function status check criteria, and has a separate section containing exit conditions . The EOP specifies to verify that the Final Safety Function Status Check Acceptance Criteria are met, and places the step such that the exit point of the EOP is clearly delineated.

1. The Safety Function Status Check Final Acceptance Criteria verifies all safety functions are being controlled prior to terminating actions taken under the EOPs. The Final Acceptance Criteria are more stringent than the Intermediate Acceptance Criteria, and therefore, demonstrate control systems have operated correctly in restoring safety functions to their desired values. When the final check is completed and all Final Acceptance Criteria are satisfied, the plant is in a condition which allows exiting of the EOPs and implementation of applicable operating procedures (OIs, AOPs and/or OPs). If the Final Acceptance Criteria are not satisfied by the time the operator reaches this point and systems are trending as prescribed by the Recovery Actions, then the operator should continue the recovery actions as necessary until the Final Acceptance Criteria can be met. The time frame in which an operator may be able to complete this procedure may not be sufficient to allow restoration of all safety functions (e.g., restoring of pressurizer level and pressure as well as S/G levels). If safety functions are not trending towards the values specified by the Final Acceptance Criteria, the operator should analyze the affected safety function to determine if additional operator actions are necessary to establish control. This would be the case if a malfunction of an automatic system not associated with the original event causing the trip has occurred, or if other than a LOCA has occurred. If the operator is unable to control the safety functions, consideration should be given to implementation of EOP-8, Functional Recovery Procedure, in order to stabilize the safety functions.

2. The operator is directed to reset any safety signals that are no longer needed to place the plant in as normal a configuration as possible prior to exiting the procedure. This is especially important if the operator will be exiting to a normal operating procedure which would not expect ESFAS signals to be present.

The EOP contains a step to commence the Administrative Post-Trip Actions. The EPG does not contain this step.

3./4. At this point, the plant has been placed in a condition where the EOPs may be terminated and further plant operations should be governed by appropriate procedures (OIs, AOPs and/or OPs). The Administrative Post-Trip Actions provide a checklist of the required administrative actions which must be completed as a result of a reactor trip. These actions include such items as performing required notifications, documentation of the trip in the transient log and performance of the Post-Trip Review. Completion of these administrative actions should not delay exiting the emergency operating procedures. They have been separated from the operational directives so administrative duties do not distract the operator from the maintenance of the safety functions and consequently, safe operation of the plant. The checkoff lines contained in the Administrative Post-Trip Actions do not require signatures or dates unless the operator desires to record that information. The steps in the Administrative Post-Trip Actions may be started at any time in the procedure once plant conditions are stable or when the operators have control of the event.

Section Number: V. SAFETY FUNCTION ACCEPTANCE CRITERIA
Step: V. Reactivity Control

For all emergency events, the reactor must be shutdown. Lowering reactor power is one positive indication that reactivity control has been established. The rapid insertion of CEAs, which occurs as a result of the reactor trip, results in a step insertion of negative reactivity into the core. This step insertion of negative reactivity is sufficient to drive the reactor subcritical, basically eliminating the contribution to reactor power from prompt neutrons. This will cause a prompt drop in reactor power to approximately 6% of the original power level. The 6% is a result of delayed neutrons which contribute to about this proportion of reactor power. Reactor power will continue to drop as the delayed neutron precursors decay. Delayed neutron precursors are those fission fragments that decay by emitting a delayed neutron. These precursors are generally grouped based on their relative half-lives. The shorter lived precursors decay rapidly away following a reactor trip causing reactor power to fall quickly following the prompt drop. As the shorter lived precursors die out and the major contributor to power becomes the longer lived precursors, the rate at which reactor power is dropping begins to follow the decay rate of these longer lived precursors. This results in a reactor power drop of about one-third of a decade every minute, or in other words, a SUR of (-)1/3 DPM. The (-)1/3 DPM drop will continue until reactor power reaches the point at which the influence of source neutrons on reactor power starts to be observable. At this point, the rate of reactor power drop will lower until delayed neutrons are no longer a significant contributor to reactor power and reactor power is predominantly influenced by source neutrons through sub-critical multiplication. Due to the behavior described above, a predictable post-trip response can be expected which consists of lowering reactor power and a negative SUR as reactor power drops into the source range where it will level off due to subcritical multiplication. These conditions are, therefore, used to verify that reactivity control has been established and that the reactor remains sub-critical. Lowering neutron power combined with a negative SUR provides an unambiguous indicator that a trip has occurred. NI power was chosen so that RCS temperature response would not interfere with the assessment of proper reactor neutronics response. In conjunction with all CEAs on the bottom, two independent indications of satisfying the reactivity safety function are provided. (Reference: Action Value Basis Document: EOP-08.01).

A CEA is considered inserted if the rod drop light (amber) or the lower electrical limit light (green) is energized. Alternate methods of checking that the CEAs are inserted are the position indications on the CEA Digital Position Readouts and the Secondary CEA Position Indication System. If more than one CEA is not inserted, adequate Shutdown Margin is not assured. The alternate requirement ensures RCS boration at a rate equivalent to or greater than that of the Tech. Spec. requirements for loss of Shutdown Margin until the RCS boron concentration is greater than 2300 PPM, which is required when more than one CEA is not fully inserted. (Reference: Action Value Basis Document: EOP-36.02, 36.05).

Step: V. Vital Auxiliaries

The criteria ensure that the plant electrical generation system is capable of responding to the LOCA. At least one 4KV Vital Bus is checked to be energized. One vital AC bus is required to power equipment necessary to maintain control of all other safety functions. Only one 4KV Vital Bus is required to be energized since the engineered safety features electrical system incorporates the two channel concept wherein independent electrical controls and power systems supply redundant 4160 volt engineered safety features. The 4160 volt engineered safety features electrical system meets the single failure criterion defined in Section 4.2 of IEEE-279 and is designed as a class 1E system.

All 125V DC Buses are checked to have voltage greater than 105 volts, since these buses are needed for vital instrumentation and control power. The 125 volt DC system is designed to furnish continuous power to the plant vital instrumentation and control systems regardless of auxiliary electrical system conditions. The reliability of the system is increased by redundancy of vital equipment and circuits, although control power for some components, most notably the RCPs, are powered only from one bus. Therefore, both bus trains are required to supply equipment needed for safe shutdown, and to ensure that actions are taken to either re-energize the appropriate bus or initiate appropriate manual actions. A bus train consists of two buses, either 11 and 22 125V DC Buses or 12 and 21 125V DC Buses. (Reference: Action Value Basis Document: EOP-29.01)

The EPG specifies at least one train of 120 VAC instrument power is available. The EOP specifies at least three 120V AC Vital Buses are energized.

At least three 120V AC Vital Buses are checked to be energized since these buses supply power to the 2 of 4 logic systems that support safety functions. If any two 120V AC Vital Buses are de-energized, two logic sensor channels will be de-energized. Since the sensor channels are de-energize to trip, and the logic channels are energize to trip, any logic channel that remains energized will have actuations for all signals. Of particular interest is the UV actuation that would normally reset, in this condition the signal will remain locked in. These buses also supply power to vital instrumentation needed to monitor the RCS. The 120 volt vital AC system is designed to furnish continuous power to the plant vital instrumentation and control systems regardless of auxiliary electrical system conditions. The reliability of the system is increased by redundancy of vital equipment and circuits. Only one set of buses is required to supply equipment needed for safe shutdown. A set of buses consist of two buses, either 11 and 14 (21 and 24) 120V AC Buses or 12 and 13 (22 and 23) 120V AC Buses. Each set powers one set of redundant equipment and circuits.

Either 1Y09 or 1Y10 (2Y09 or 2Y10) is checked to be energized since these buses supply power to the plant computers and data acquisition systems. The 208/120V Instrument AC system is designed to furnish power to all plant instruments other than those supplied from the DC and the vital AC systems.

Step: V. RCS Pressure And Inventory

This procedure is specifically designed to respond to conditions that threaten RCS pressure and inventory safety function, so the criteria that have been established are very broad. The limits ensure conditions are within the maximum Pressure-Temperature limits allowed per Tech. Specs. to prevent brittle fracture by specifying pressure be less than the upper limits of Attachment (1).

The initial acceptable pressurizer level was chosen to reflect the minimum level that corresponds to the lowest level, which can be accepted before the pressurizer is considered drained. There is no upper limit on pressurizer level, since the safety function can be considered satisfied even if the pressurizer is water solid. If pressurizer level is less than the minimum level for inventory control, operators use reactor vessel level and the SI flow to confirm acceptable inventory control. At least one charging pump is required to maintain RCS inventory until the RCS can be depresssurized below the HPSI pump shutoff head. SI flow within the SI delivery curves provides implicit assurance that inventory control is being maintained with reactor vessel level greater than the top of the active fuel region. A final level band of 101 to 180 inches was chosen to ensure inventory control has been established while allowing for some drift in system response. (Reference: Action Value Basis Documents: EOP-19.01, 19.06, 19.09, 19.10).

The subcooling limits were established to be broad to accommodate the loss of subcooling which is possible during a LOCA. During the initial phase of the LOCA while the loss of reactor coolant exceeds makeup, the pressurizer is expected to empty, the reactor vessel level is expected to drop and the subcooling for the core will drop below the 50 to 70°F which is typical for an uncomplicated reactor trip. This margin is considered to be more than adequate to prevent void formation. 20°F is the lower limit on subcooling contained in the EPGs and is based on engineering judgment as to the minimum subcooled margin required to ensure an adequate amount of fluid in its desire state to remove decay heat. The subcooling value is used throughout the EOPs to verify adequate core cooling and is the primary parameter used to validate pressurizer level indication as representative of total RCS inventory. If the RCS is subcooled throughout, then pressurizer level provides a usable indication of acceptable RCS inventory. The upper subcooled margin limit of 140°F was originally chosen to prevent exceeding the noncritical cooldown curve of Attachment (1), <u>RCS Pressure Temperature Limits</u>. These curves have since been changed to reflect the installation of Variable Low Temperature Overpressure Protection, which permits operation with subcooling greater than 140°F throughout the range. However the 140°F limit has been maintained due to operator familiarity, Simulator Validations have shown the value is achievable, and to account for instrument errors. This provides the operators a convenient method of ensuring the P-T relationship of the Technical Specification figures are not violated during the cooldown and depressurization. (Reference: Action Value Basis Documents: EOP-23.01, 23.03).

The EPG specifies under condition 1 that reactor vessel level is above the top of the hot leg nozzles, and under condition 2 the reactor vessel level is greater than top of the active fuel region. The EOP specifies that the core is covered for all conditions.

> *The EPG uses level above the top of the hot leg as a corroborating parameter for pressurizer level. Further, if the RCS is not subcooled, pressurizer level may not be a valid indication that the core is covered. As stand alone criteria, as stated in condition 2 of the EPG, the requirement for RVLMS indication to satisfy the safety function is greater than top of active fuel region. The EOP corroborates pressurizer level when required, with minimum subcooling and Reactor Vessel level indicates core covered.*

The requirement that the core is covered based on Reactor Vessel level indication ensures the minimum inventory necessary to remove core heat is available. Indication that the core is covered taken in conjunction with 30°F subcooling is an indication that RCS inventory control is established.
(Reference: G.C. Creel, BG&E Vice President Nuclear Energy, letter to the NRC dated December 17, 1990)

Step: V. Core And RCS Heat Removal

The EPG designates to use Th RTD and representative CET temperatures when evaluating Core Heat Removal. The EOPs do not use Th RTDs.

The CET criteria was chosen to flag conditions where core cooling is insufficient. A superheated condition in the RCS can only occur with core uncovery. Core uncovery results from a loss of RCS inventory, which generally results from two accident scenarios, a LOCA, or a loss of steam generators as a heat sink. LOCA results directly in a loss of inventory. A loss of inventory, leading to core uncovery, can also result from a loss of S/G heat sink which causes RCS pressure to rise high enough to lift the PORVs and pressurizer safeties. Due to the low pressures associated with LOCA events, the variable superheated temperatures indicative of core uncovery must be determined. The margin to superheat is to account for instrument uncertainties while at saturated conditions. If core uncovery occurs, temperature of the superheated steam will rise above this margin. Core uncovery indicates an advanced phase in the approach to inadequate core cooling and is undesirable. If at anytime core uncovery is approached or indicated, the operator should review the effectiveness of earlier measures and take all possible steps to restore the inventory to at least a core covered condition as indicated by the CETs, Subcooled Margin Monitor, or Reactor Vessel level indication. Core covered as indicated by Reactor Vessel level indication and CETs not superheated are corroborative indications that core heat removal is adequate. (Reference: Action Value Basis Document: EOP-24.33)

During a LOCA, adequate RCS heat removal will be maintained as long as adequate inventory is maintained and if at least one steam generator is available for removing heat (capable of steam flow and feed flow). This is of primary concern for small break LOCAs. If the Turbine Bypass Valves or Atmospheric Dump Valves are operating correctly, S/G steaming should maintain RCS T_{COLD} in a stable condition unless cooldown is in progress. Therefore, the acceptance criteria require that T_{COLD} be constant or lowering.

The required initial S/G level ensures that the S/G has adequate inventory to remove heat if a steaming path exists. The level band will only be maintained during steaming if feed flow is adequate. This is demonstrated by level trending to the LOCA normal control band. This band is required to ensure the S/G tubes are covered to comply with the LOCA safety analysis assumption. S/G final level is checked to ensure that Main or Auxiliary Feedwater is operating to maintain S/G level. (Reference: Action Value Basis Documents: EOP-27.03, 27.10, 27.12).

Step: V. Containment Environment

The EPG contains three safety functions involved with containment control. The EOP contains two. Each of the three EPG safety functions contain criteria for normal containment conditions and criteria for abnormal containment conditions. The EOP does not contain criteria for normal containment conditions to monitor the safety functions. Further the EPG specifies CIAS present and operation of required containment cooling systems as SFSC criteria. The EOP does not check ESFAS equipment as part of the SFSC.

> *The purpose of the SFSC is to continually verify the status of the safety functions. By satisfying the SFSC acceptance criteria, the operators are assured that the actions being taken are maintaining the plant in a safe condition. On the other hand, if SFSC criteria are not satisfied, the operators are promptly alerted to the situation. In this case the operators will take corrective actions to satisfy the safety functions, implement another ORP, or exit to the Functional Recovery Procedure. The SFSC is designed to be used to provide an independent assessment of the status of safety functions. The EOP directly monitors parameters to satisfy the three EPG safety functions. These parameters are divided into two safety functions, one for inside and one for outside containment. Determining the required ESFAS equipment and operation of that equipment does not directly assure the containment conditions are being maintained. The EOP operates the ESFAS equipment as part of the recovery actions. The EOP SFSC verifies the functionality of the equipment to maintain the safety function. The format of the three EPG safety functions, including the operation of ESFAS equipment requires criteria for normal containment conditions. By reformatting the SFSC criteria to directly monitor parameters, the EOP does not require defining normal containment conditions that are not threatening the safety function.*

Containment environment is expected to be greatly effected during a Loss Of Coolant Accident inside containment. The containment peak pressure design limit is 50 PSIG during LOCA or steam line break conditions. The initial acceptance criteria were chosen to ensure containment pressure remains within design limits. The final acceptance criteria were chosen to reflect containment environment has been restored to a condition below CIS and SIAS setpoint and with pressure no longer threatening containment integrity. (Reference: Action Value Basis Documents: EOP-04.02, 04.05)

The containment temperature criteria can not be applied during a pressurizing event. Containment temperature design limits are assured by containment pressure. This is due to local effects of possible steam jets produced by the event. The final acceptance criteria were chosen to reflect containment environment has been restored to a condition below CIS and SIAS setpoint and with pressure no longer threatening containment integrity. (Reference: Action Value Basis Document: EOP-06.03)

If the Containment radiation monitors indicate an unexplained trend or alarm, then some off normal event may be occurring. Any containment radiation monitor can be used to indicate the off normal event. The containment high range radiation monitor is not expected to be received though, except in extreme situations. Calculations have shown that this alarm will not alarm even during LOCA conditions unless fuel failure has occurred. There should be no radiation alarms received during an uncomplicated reactor trip. (Reference: S.M. Mirsky, Principal Engineer - Analytical Support Unit, memo to J.F. Lohr dated November 13, 1986.)

The Containment Environment Safety Function should not be threatened from combustible Gases as long as hydrogen levels are less than 0.5%. If hydrogen levels are greater than 0.5%, then operation of the hydrogen recombiners should maintain the hydrogen concentration below the lower flammability limit of 4%. As a last resort, the hydrogen purge system can be operated to ensure containment integrity is maintained. The Plant Technical Support Center will review containment conditions and recommend a hydrogen purge if conditions warrant. The safety function initial acceptance criteria require hydrogen concentration be less than 0.5% or the hydrogen recombiners be operating or the hydrogen purge system is being operated per the Plant Technical Support Center recommendations. The final acceptance criteria ensure hydrogen concentration has been reduced to acceptable limits prior to exiting this procedure. The note states that the acceptance criteria may be omitted until chemistry has been able to place hydrogen monitors in service. This is allowed due to the hydrogen accumulation rate and the time that it will take for chemistry to perform this action. (Reference: Action Value Basis Documents: EOP-13.01, 13.02)

Step: V. Radiation Levels External To Containment

During a LOCA outside of containment, activity is expected to be detected on the Noble Gas Monitors and the Main Vent Gaseous RMS. Initial criteria for these monitors were, therefore, not established. The final criteria ensures plant conditions have been restored to a state were radiation is no longer being released to the environment. If activity were detected on the B/D RMS or the Condenser Off-Gas RMS, it would indicate a SGTR was occurring, and is not expected during a LOCA. If activity is detected on the Condenser Off-Gas or S/G B/D RMS, the operator should reevaluate plant conditions to verify a LOCA and not another event or multiple events have occurred. RMS trends are required, as the receipt of alarms for indication of an off-normal event is dependent on RCS activity levels. It should be noted though, that the Condenser Off-Gas RMS, the S/G Blowdown and the Main Vent Gaseous RMS would be lost when non-vital 480V buses are de-energized. If only one 4KV bus is energized, some of these RMS units will be in alarm, but not energized. Receipt of an alarm as a result of loss of power to the RMS does not cause the SFSC to be not satisfied. The operator should verify the alarm is valid due to detection of radiation and not caused by loss of power or RMS malfunction. (Reference: Ian Sommerville, BGE Nuclear Engineering Unit, NEU 94-239, memo to C.R. Stancil dated August 26, 1994)