Westinghouse Electric Corporation

Water Reactor Divisions

Box 355
Pittsburgh Pennsylvania 15230

April 3, 1984
CAW-84-28

Mr. Harold R. Denton
Director of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Phillips Building
7920 Norfolk Avenue
Bethesda, Maryland 20014

APPLICATION FOR WITHHOLDING PROPRIETARY

INFORMATION FROM PUBLIC DISCLOSURE

SUBJECT: Reactor Coolant System Flow Measurement Uncertainty for SNUPPS

REF: Letter from SNUPPS to NRC (Petrick to Denton), April, 1984

Dear Mr. Denton:

The proprietary material transmitted by the reference letter for which withholding is being requested by the Standardized Nuclear Unit Power Plant System (SNUPPS) is of the same technical type as that proprietary material previously submitted by Westinghouse concerning Reactor Protection System/Engineered Safety Features Actuation System Setpoint Methodology. The previous application for withholding, AW-76-60, was accompanied by an affidavit signed by the owner of the proprietary information, Westinghouse Electric Corporation. Further, the affidavit submitted to justify the previous material was approved by the Commission on April 17, 1978, and is equally applicable to the subject material. The subject proprietary material is being submitted by the Standardized Nuclear Unit Power Plant System (SNUPPS) for the Kansas City Power and Light Company and Kansas Gas & Electric Company's Wolf Creek Unit (STN 50-482) and the Union Electric Company's Callaway Unit (STN 50-483).

Accordingly, this letter authorizes the utilization by SNUPPS of the previously furnished affidavit. A copy of the affidavit, AW-76-60, dated December 1, 1976, is attached.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference CAW-84-28 and should be addressed to the undersigned.

Very truly yours,

Robert A. Wiesemann

Robert A. Wiesemann, Manager
Regulatory & Legislative Affairs

/dr
Attachment

cc: E. C. Shomaker, Esq.
Office of the Executive Legal Director, NRC

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF ALLEGHENY:

Before me, the undersigned authority, personally appeared Robert A. Wiesemann, who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Corporation ("Westinghouse") and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

Robert A. Wiesemann

Robert A. Wiesemann, Manager
Licensing Programs

Sworn to and subscribed before me this 2 day of December 1976.

[illegible]

Notary Public

(1) I am Manager, Licensing Programs, in the Pressurized Water Reactor Systems Division, of Westinghouse Electric Corporation and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing or rulemaking proceedings, and am authorized to apply for its withholding on behalf of the Westinghouse Water Reactor Divisions.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.790 of the Commission's regulations and in conjunction with the Westinghouse application for withholding accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse Nuclear Energy Systems in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.790 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitutes Westinghouse policy and provides the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

(g) It is not the property of Westinghouse, but must be treated as proprietary by Westinghouse according to agreements with the owner.

There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information which is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition in those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iii) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.790, it is to be received in confidence by the Commission.

(iv) The information is not available in public sources to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in the attachment to Westinghouse letter number NS-CE-1298, Eicheldinger to Stolz, dated December 1, 1976, concerning information relating to NRC review of WCAP-8567-P and WCAP-8568 entitled, "Improved Thermal Design Procedure," defining the sensitivity of DNB ratio to various core parameters. The letter and attachment are being submitted in response to the NRC request at the October 29, 1976 NRC/Westinghouse meeting.

This information enables Westinghouse to:

(a) Justify the Westinghouse design.

(b) Assist its customers to obtain licenses.

(c) Meet warranties.

(d) Provide greater operational flexibility to customers assuring them of safe and reliable operation.

(e) Justify increased power capability or operating margin for plants while assuring safe and reliable operation.

(f) Optimize reactor design and performance while maintaining a high level of fuel integrity.

Further, the information gained from the improved thermal design procedure is of significant commercial value as follows:

(a) Westinghouse uses the information to perform and justify analyses which are sold to customers.

(b) Westinghouse sells analysis services based upon the experience gained and the methods developed.

Public disclosure of this information concerning design procedures is likely to cause substantial harm to the competitive position of Westinghouse because competitors could utilize this information to assess and justify their own designs without commensurate expense.

The parametric analyses performed and their evaluation represent a considerable amount of highly qualified development effort. This work was contingent upon a design method development program which has been underway during the past two years. Altogether, a substantial amount of money and effort has been expended by Westinghouse which could only be duplicated by a competitor if he were to invest similar sums of money and provided he had the appropriate talent available.

Further the deponent sayeth not.

Attachment 1

STATUS OF TECHNICAL SPECIFICATION OPEN ISSUES

SPECIFICATION	SUBJECT	ISSUE	ACTION
Tab. 2.2-1 Tab. 3.3-4	Reactor Trip and ESFAS Setpoints	Provide final values for Wolf Creek	Wolf Creek values should be forwarded by 7/1/84.
3.1.2.1 3.1.2.5 3.1.2.6 3.1.2.7	Boration Systems	This specification, applicable in Modes 4, 5, 6, refers to Specification 3.1.2.5 which is applicable in modes 5 and 6 only. The volumes and boron concentration in 3.1.2.5 need to be revised to make the specification applicable in Mode 4 also.	Included in Attachment 2
3.2.3	RCS Flowrate	The NRC requested that SNUPPS provide background information on how the 2.0% RCS flow uncertainty in this specification was obtained. In a 3/19/84 telecon with the Callaway Project Manager (J. Holonich) SNUPPS reported that the 2% figure was derived using the same methodology as was used for Seabrook, Catawba, and McGuire. The methodology used is a generic one whose results envelope the SNUPPS design.	Included in Attachments 2 and 3. The writeup in attachment 3 is applicable to Callaway only until Wolf Creek confirms its maintenance and test equipment errors. Wolf Creek's submittal will be forwarded under separate cover.
Tab 3.3-7	Seismic Instrumentation	The triaxial response spectrum recorders require setpoints on each of the three axes.	Included in Attachment 2
Tab 3.3-10 Tab 4.3-7	Accident Monitoring Instrumentation	The RCS radiation monitor is not part of the SNUPPS design and its inclusion therein has not been committed to by SNUPPS.	Possible appeal issue
Tab 3.3-13 Tab.4.3-9	Radioactive Gaseous Effluent Monitoring	It is not necessary to place requirements on the containment purge system samplers since these are not the final monitors on the effluent discharge path.	Included in Attachment 2
Tab 4.3-8	Radioactive Liquid Effluent Monitoring	Revise the wording in item 2d.	Included in Attachment 2

Attachment 1

SPECIFICATION	SUBJECT	ISSUE	ACTION
3.4.9.3 3.8.1.2 3.8.2.2 3.8.3.2	RHR Suction Relief Valves	Justify use of the RHR suction relief valves for cold overpressurization protection. The NRC will allow credit to be taken for only one RHR relief valve at a time - combined with one PORV.	Possible appeal item
3.5.5	Boron Injection Tank	Justification has been provided for deletion of this specification based on a revised minimum boron concentration.	NRC complete review on the SNUPPS submittal
4.6.1.2.c	Containment Type A Supplemental Leak Tests	A recent version of the Technical Specifications changed the acceptance criteria for the supplemental tests and removed reference to reduced pressure testing. The NRC (J. Huang) has agreed that the specification is incorrect as presently stated.	NRC Project Managers for SNUPPS will follow this issue to assure the specification is corrected.
3.6.1.4	Containment Pressure Limits	Provide the operating pressure limits for this specification.	Included in Attachment 2
3.6.1.6	Containment Structural Integrity	The NRC changed its position on the previously agreed upon specification. The NRC position is that the proposed specification allows too much time for action after identifying possible structural integrity problems and that the surveillances contain action requirements.	Possible appeal issue
3.6.3.b,c	Containment Isolation Valves	The exclusion of the requirements of specification 3.0.4 was recently deleted by the NRC. This puts the plants in a position where an upward mode change cannot be made if an isolation valve is inoperable, even if the affected penetration is isolated.	Possible appeal issue
4.7.6.e.2	Control Room Emergency Ventillation	Delete reference to a high smoke density test signal.	Included in Attachment 2

Attachment 1

SPECIFICATION	SUBJECT	ISSUE	ACTION
3.7.10.1	Fire Suppression Water System	Change water supply tank volume requirements - Callaway only.	Included in Attachment 2
3.7.11	Fire Barrier Penetrations	The present LCO has a typographical error that makes identification of "fire rated assembly penetrations" uncertain. In addition, a clarification is required to show that "cable tray" vice "cable" penetrations are the items of concern.	Included in Attachment 2
4.8.1.1.1.b	Fire Suppression for ESF Transformers	SNUPPS contends that the surveillance for these fire protection systems should be located with the applicable fire protection specifications 3.3.3.7 and 3.7.10.	Included in Attachment 2
4.8.1.1.2	Solid State Load Sequencer Testing	SNUPPS contends that this surveillance should be located with the other ESFAS instrumentation in Specification 3.3.2. This would place the requirements in their proper context. In addition, a note should be added indicating that the Actuation Logic Test does not include a continuity check.	Included in Attachment 2
4.8.1.1.3	Diesel Generator Voltage Requirements	Expand allowable voltage range.	Included in Attachment 2
Tab 3.8-1	Containment Penetration Conductor Overcurrent Protection Devices	Correct table values for 13.8 kV switchgear.	Included in Attachment 2
Fig 6.2-1 Fig 6.2-2	Organizational Charts	Provide up-to-date versions of the organizational charts for Callaway.	Included in Attachment 2

JHR/dck/2a3,4,6

Attachment 2

PROPOSED TECHNICAL SPECIFICATION CHANGES AND JUSTIFICATIONS

REACTIVITY CONTROL SYSTEMS

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3/4.1.2 BORATION SYSTEMS

FLOW PATH - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.1 As a minimum, one of the following boron injection flow paths shall be OPERABLE and capable of being powered from an OPERABLE emergency power source:

a. A flow path from the Boric Acid Storage System via a boric acid transfer pump and a centrifugal charging pump to the Reactor Coolant System if the Boric Acid Storage System in Specification 3.1.2.5a (MODES 5 and 6) or Specification 3.1.2.6a (MODE 4) is OPERABLE; or

b. The flow path from the refueling water storage tank via a centrifugal charging pump to the Reactor Coolant System if the refueling water storage tank in Specification 3.1.2.5b (MODES 5 and 6) or Specification 3.1.2.6b (MODE 4) is OPERABLE.

APPLICABILITY: MODES 4, 5, and 6.

ACTION:

With none of the above flow paths OPERABLE or capable of being powered from an OPERABLE emergency power source, suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

SURVEILLANCE REQUIREMENTS

4.1.2.1 At least one of the above required flow paths shall be demonstrated OPERABLE at least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

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BORATED WATER SOURCE - ~~SHUTDOWN~~ MODES 5 AND 6

LIMITING CONDITION FOR OPERATION

3.1.2.5 As a minimum, one of the following borated water sources shall be OPERABLE:

a. A Boric Acid Storage System with:

1) A minimum contained borated water volume of ~~2713~~ 2968 gallons,

2) Between 7000 and 7700 ppm of boron, and

3) A minimum solution temperature of 65°F.

b. The refueling water storage tank (RWST) with:

1) A minimum contained borated water volume of ~~53,500~~ 55,416 gallons,

2) A minimum boron concentration of 2000 ppm, and

3) A minimum solution temperature of 37°F.

APPLICABILITY: MODES 5 and 6.

ACTION:

With no borated water source OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

SURVEILLANCE REQUIREMENTS

4.1.2.5 The above required borated water source shall be demonstrated OPERABLE:

a. At least once per 7 days by:

1) Verifying the boron concentration of the water,

2) Verifying the contained borated water volume, and

3) Verifying the Boric Acid Storage System solution temperature when it is the source of borated water.

b. At least once per 24 hours by verifying the RWST temperature when it is the source of borated water and the outside air temperature is less than 37°F.

REACTIVITY CONTROL SYSTEMS

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BORATED WATER SOURCES - ~~OPERATING~~ MODE 4

LIMITING CONDITION FOR OPERATION

3.1.2.6 As a minimum, one of the following borated water source(s) shall be OPERABLE as required by Specification 3.1.2.~~2~~1:

a. A Boric Acid Storage System with:

1) A minimum contained borated water volume of ~~16,142~~ 17,658 gallons,

2) Between 7000 and 7700 ppm of boron, and

3) A minimum solution temperature of 65°F.

b. The refueling water storage tank (RWST) with:

1) A minimum contained borated water volume of 394,000 gallons,

2) Between 2000 and 2100 ppm of boron,

3) A minimum solution temperature of 37°F, and

4) A maximum solution temperature of 100°F.

APPLICABILITY: MODE~~S~~ ~~1, 2, 3, and~~ 4.

ACTION:

~~a. With the Boric Acid Storage System inoperable and being used as one of the above required borated water sources, restore the storage system to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and borated to a SHUTDOWN MARGIN equivalent to at least 1% Δk/k at 200°F; restore the Boric Acid Storage System to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.~~

a. ~~b.~~ With no borated water source OPERABLE, restore one borated water source ~~the RWST inoperable, restore the tank~~ to OPERABLE status within ~~1 hour or be in at least HOT STANDBY within~~ the next 6 hours or be ~~and~~ in COLD SHUTDOWN within the following ~~30~~ 24 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.6 The above required borated water source shall be demonstrated OPERABLE by the performance of each of the requirements of specification 4.1.2.5

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BORATED WATER SOURCES - ~~OPERATING~~ MODES 1, 2, AND 3

LIMITING CONDITION FOR OPERATION

3.1.2.~~6~~ 7 As a minimum, the following borated water source(s) shall be OPERABLE as required by Specification 3.1.2.2:

a. A Boric Acid Storage System with:

1) A minimum contained borated water volume of ~~16,142~~ 17,658 gallons,

2) Between 7000 and 7700 ppm of boron, and

3) A minimum solution temperature of 65°F.

b. The refueling water storage tank (RWST) with:

1) A minimum contained borated water volume of 394,000 gallons,

2) Between 2000 and 2100 ppm of boron,

3) A minimum solution temperature of 37°F, and

4) A maximum solution temperature of 100°F.

APPLICABILITY: MODES 1, 2, and 3~~, and 4~~.

ACTION:

a. With the Boric Acid Storage System inoperable and being used as one of the above required borated water sources, restore the storage system to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and borated to a SHUTDOWN MARGIN equivalent to at least 1% Δk/k at 200°F; restore the Boric Acid Storage System to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

b. With the RWST inoperable, restore the tank to OPERABLE status within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

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4.1.2.7 ~~4.1.2.6~~ Each borated water source shall be demonstrated OPERABLE:

a. At least once per 7 days by:

1) Verifying the boron concentration in the water,

2) Verifying the contained borated water volume of the water source, and

3) Verifying the Boric Acid Storage System solution temperature when it is the source of borated water.

b. At least once per 24 hours by verifying the RWST temperature when the outside air temperature is either less than 37°F or greater than 100°F.

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MODERATOR TEMPERATURE COEFFICIENT (Continued)

The most negative MTC value equivalent to the most positive moderator density coefficient (MDC), was obtained by incrementally correcting the MDC used in the FSAR analyses to nominal operating conditions. These corrections involved subtracting the incremental change in the MDC associated with a core condition of all rods inserted (most positive MDC) to an all rods withdrawn condition and, a conversion for the rate of change of moderator density with temperature at RATED THERMAL POWER conditions. This value of the MDC was then transformed into the limiting MTC value -4.1×10^{-4} $\Delta k/k/°F$. The MTC value of -3.2×10^{-4} $\Delta k/k/°F$ represents a conservative value (with corrections for burnup and soluble boron) at a core condition of 300 ppm equilibrium boron concentration and is obtained by making these corrections to the limiting MTC value of -4.1×10^{-4} $\Delta k/k/°F$.

The Surveillance Requirements for measurement of the MTC at the beginning and near the end of the fuel cycle are adequate to confirm that the MTC remains within its limits since this coefficient changes slowly due principally to the reduction in RCS boron concentration associated with fuel burnup.

3/4.1.1.4 MINIMUM TEMPERATURE FOR CRITICALITY

This specification ensures that the reactor will not be made critical with the Reactor Coolant System average temperature less than 551°F. This limitation is required to ensure: (1) the moderator temperature coefficient is within its analyzed temperature range, (2) the trip instrumentation is within its normal operating range, (3) the pressurizer is capable of being in an OPERABLE status with a steam bubble, and (4) the reactor vessel is above its minimum RT_{NDT} temperature.

3/4.1.2 BORATION SYSTEMS

The Boration Systems ensure that negative reactivity control is available during each MODE of facility operation. The components required to perform this function include: (1) borated water sources, (2) centrifugal charging pumps, (3) separate flow paths, (4) boric acid transfer pumps, and (5) an emergency power supply from OPERABLE diesel generators.

With the RCS average temperature above 350 ~~200~~°F, a minimum of two boron injection flow paths are required to ensure single functional capability ~~in the event an assumed failure renders one of the flow paths inoperable.~~ See insert, following pg The boration capability of a single ~~either~~ flow path is sufficient to provide a SHUTDOWN MARGIN from expected operating conditions of 1.3% $\Delta k/k$ after xenon decay and cooldown to 200°F. The maximum expected boration capability requirement occurs at EOL from full power equilibrium xenon conditions and requires 17,658 ~~12,117~~ gallons of 7000 ppm borated water from the boric acid storage tanks or 83,754 ~~72,096~~ gallons of 2000 ppm borated water from the RWST.

Insert for page B 3/4 1-2

In MODE 4 one, and only one, flowpath is required to be OPERABLE as is necessary to assure that a mass addition pressure transient can be relieved by the operation of a single PORV or RHR suction relief valve.

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BORATION SYSTEMS (Continued)

With the RCS temperature below 200°F, one Boration System is acceptable without single failure consideration on the basis of the stable reactivity condition of the reactor and the additional restrictions prohibiting CORE ALTERATIONS and positive reactivity changes in the event the single Boron Injection System becomes inoperable.

The limitation for a maximum of one centrifugal charging pump to be OPERABLE and the Surveillance Requirement to verify all charging pumps except the required OPERABLE pump to be inoperable in MODES 4, 5, and 6 provides assurance that a mass addition pressure transient can be relieved by the operation of a single PORV or RHR suction relief valve.

The boron capability required below 200°F is sufficient to provide a SHUTDOWN MARGIN of 1% $\Delta k/k$ after xenon decay and cooldown from 200°F to 140°F. This condition requires either ~~2213~~ gallons of 7000 ppm borated water from the boric acid storage tanks or ~~12,11~~7 gallons of 2000 ppm borated water from the RWST.
14,076 2968

The contained water volume limits include allowance for water not available because of discharge line location and other physical characteristics.

The limits on contained water volume and boron concentration of the RWST also ensure a pH value of between 8.5 and 11.0 for the solution recirculated within Containment after a LOCA. This pH band minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components.

The OPERABILITY of one Boration System during REFUELING ensures that this system is available for reactivity control while in MODE 6.

3/4.1.3 MOVABLE CONTROL ASSEMBLIES

The specifications of this section ensure that: (1) acceptable power distribution limits are maintained, (2) the minimum SHUTDOWN MARGIN is maintained, and (3) the potential effects of rod misalignment on associated accident analyses are limited. OPERABILITY of the control rod position indicators is required to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits. Verification that the Digital Rod Position Indicator agrees with the demanded position within ± 12 steps at 24, 48, 120 and 228 steps withdrawn for the Control Banks and 18, 210 and 228 steps withdrawn for the Shutdown Banks provides assurances that the Digital Rod Position Indicator is operating correctly over the full range of indication. Since the Digital Rod Position System does not indicate the actual shutdown rod position between 18 steps and 210 steps, only points in the indicated ranges are picked for verification of agreement with demanded position.

Specifications 3.1.2.1
3.1.2.5
3.1.2.6
3.1.2.7
B 3/4.1.2

Justification

These changes are necessary in order to complete the Technical Specification revisions prompted by the SNUPPS cold overpressurization mitigation system. The previous version of the above specifications did not accurately indicate mode requirements or borated water volumes.

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3/4.2.3 RCS FLOW RATE AND NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR

LIMITING CONDITION FOR OPERATION

3.2.3 The combination of indicated Reactor Coolant System (RCS) total flow rate and R shall be maintained within the region of allowable operation shown on Figure 3.2-3 for four loop operation:

Where:

a. $R = \dfrac{F^N_{\Delta H}}{1.49\ [1.0 + 0.2\ (1.0 - P)]}$,

b. $P = \dfrac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$, and

c. $F^N_{\Delta H}$ = Measured values of $F^N_{\Delta H}$ obtained by using the movable incore detectors to obtain a power distribution map. The measured values of $F^N_{\Delta H}$ shall be used to calculate R since Figure 3.2-3 includes penalties for ~~undetected feedwater venturi fouling of 0.1% and for~~ measurement uncertainties of 2.0% for flow and 4% for incore measurement of $F^N_{\Delta H}$

APPLICABILITY: MODE 1.

ACTION:

With the combination of RCS total flow rate and R outside the region of acceptable operation shown on Figure 3.2-3:

a. Within 2 hours either:

1. Restore the combination of RCS total flow rate and R to within the above limits, or

2. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER and reduce the Power Range Neutron Flux - High Trip Setpoint to less than or equal to 55% of RATED THERMAL POWER within the next 4 hours.

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LIMITING CONDITION FOR OPERATION

ACTION (Continued)

b. Within 24 hours of initially being outside the above limits, verify through incore flux mapping and RCS total flow rate comparison that the combination of R and RCS total flow rate are restored to within the above limits, or reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 2 hours, and

c. Identify and correct the cause of the out-of-limit condition prior to increasing THERMAL POWER above the reduced THERMAL POWER limit required by ACTION a.2. and/or b., above; subsequent POWER OPERATION may proceed provided that the combination of R and indicated RCS total flow rate are demonstrated, through incore flux mapping and RCS total flow rate comparison, to be within the region of acceptable operation shown on Figure 3.2-3 prior to exceeding the following THERMAL POWER levels:

   1. A nominal 50% of RATED THERMAL POWER,

   2. A nominal 75% of RATED THERMAL POWER, and

   3. Within 24 hours of attaining greater than or equal to 95% of RATED THERMAL POWER.

SURVEILLANCE REQUIREMENTS

4.2.3.1 The provisions of Specification 4.0.4 are not applicable.

4.2.3.2 The combination of indicated RCS total flow rate and R shall be determined to be within the region of acceptable operation of Figure 3.2-3:

a. Prior to operation above 75% of RATED THERMAL POWER after each fuel loading, and

b. At least once per 31 Effective Full Power Days.

4.2.3.3 The indicated RCS total flow rate shall be verified to be within the region of acceptable operation of Figure 3.2-3 at least once per 12 hours when the most recently obtained value of R, obtained per Specification 4.2.3.2, is assumed to exist.

4.2.3.4 The RCS loop flow rate indicators shall be subjected to a CHANNEL CALIBRATION at least once per 18 months.

4.2.3.5 The RCS total flow rate shall be determined by precision heat balance measurement at least once per 18 months. Insert A, following page

4.2.3.6 Insert B, following page

Insert A

4.2.3.5 (cont) Within seven days prior to performing the precision heat balance, the instrumentation used for determination of steam pressure, feedwater pressure, feedwater temperature, and feedwater venturi delta P in the calorimetric calculations, shall be calibrated.

Insert B

4.2.3.6 The feedwater venturi shall be inspected for fouling and cleaned as necessary at least once per 18 months.

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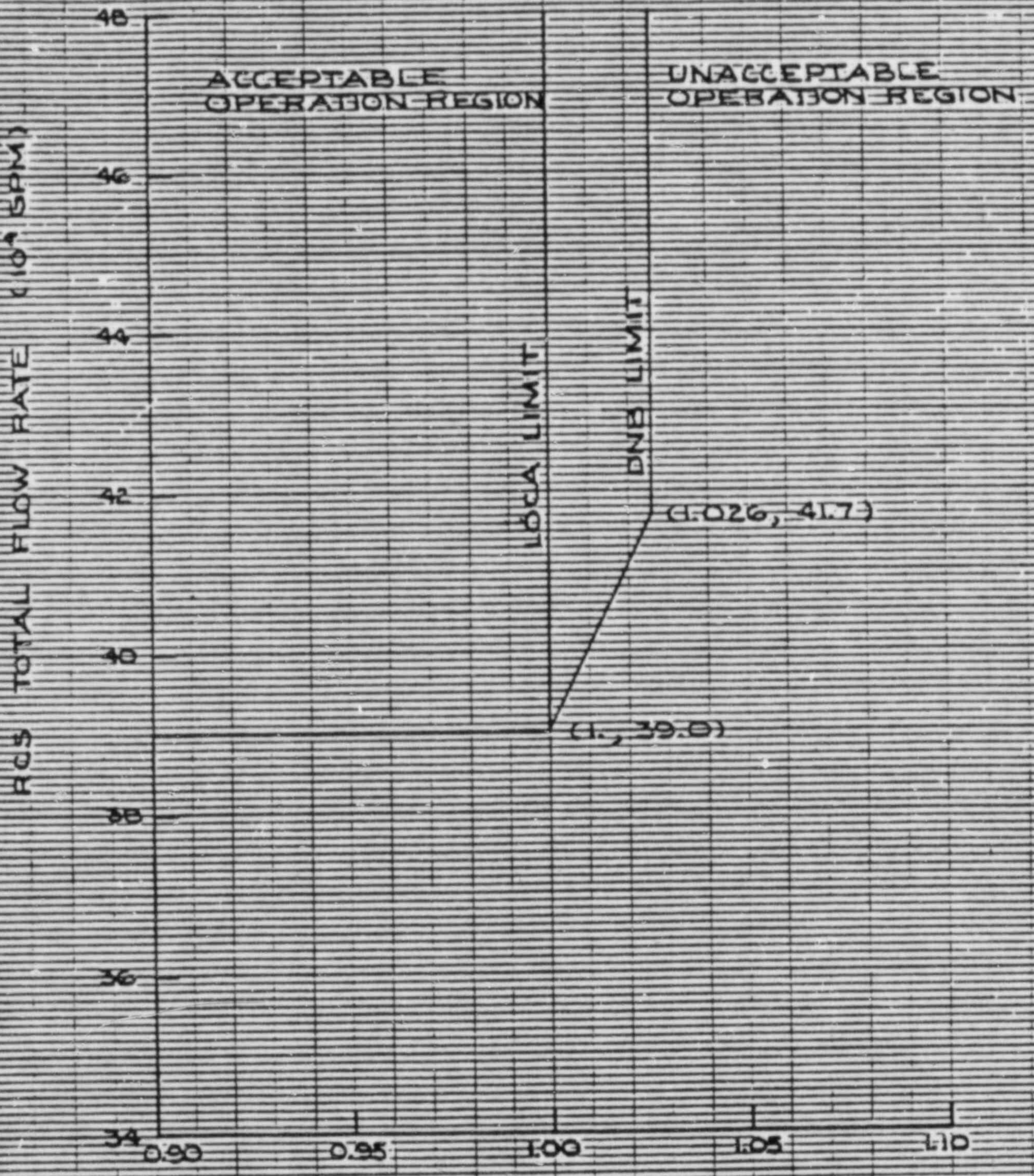
MEASUREMENT UNCERTAINTIES OF 2.0% FOR FLOW AND 4.0% FOR INCORE MEASUREMENT OF $F^N_{\Delta H}$ ARE INCLUDED IN THIS FIGURE.



$$R_1 = F^N_{\Delta H} / 1.49 [1.0 + 0.2 (1.0 - P)]$$

FIGURE 3.2-3 RCS TOTAL FLOW RATE VS. R

CALLAWAY FOUR-LOOP OPERATION

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HEAT FLUX HOT CHANNEL FACTOR, and RCS FLOW RATE AND NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR (Continued)

The Radial Peaking Factor, F_{xy} (Z), is measured periodically to provide assurance that the Hot Channel Factor, $F_Q(Z)$, remains within its limit. The F_{xy} limit for RATED THERMAL POWER (F_{xy}^{RTP}) as provided in the Radial Peaking Factor Limit Report per Specification 6.9.1.9 was determined from expected power control maneuvers over the full range of burnup conditions in the core.

When RCS flow rate and $F_{\Delta H}^{N}$ are measured, no additional allowances are necessary prior to comparison with the limits of Figure 3.2-3. Measurement errors of 2% for RCS total flow rate and 4% for $F_{\Delta H}^{N}$ have been allowed for in determination of the design DNBR value.

The measurement error for RCS total flow rate is based upon performing a precision heat balance and using the result to calibrate the RCS flow rate indicators. Potential fouling of the feedwater venturi which might not be detected could bias the result from the precision heat balance in a non-conservative manner. Therefore, an inspection is performed ~~a penalty of 0.1% for undetected fouling of~~ of the feedwater venturi each refueling. ~~is included in Figure 3.2-3. Any fouling which might bias the RCS flow rate measurement greater than 0.1% can be detected by monitoring and trending various plant performance parameters. If detected, action shall be taken before performing subsequent precision heat balance measurements, i.e., either the effect of the fouling shall be quantified and compensated for in the RCS flow rate measuremet or the venturi shall be cleaned to eliminate the fouling.~~ Add insert, following page

The 12-hour periodic surveillance of indicated RCS flow is sufficient to detect only flow degradation which could lead to operation outside the acceptable region of operation shown on Figure 3.2-3.

3/4.2.4 QUADRANT POWER TILT RATIO

The QUADRANT POWER TILT RATIO limit assures that the radial power distribution satisfies the design values used in the power capability analysis. Radial power distribution measurements are made during STARTUP testing and periodically during power operation.

The limit of 1.02, at which corrective action is required, provides DNB and linear heat generation rate protection with x-y plane power tilts. A limit of 1.02 was selected to provide an allowance for the uncertainty associated with the indicated power tilt.

The 2-hour time allowance for operation with a tilt condition greater than 1.02 but less than 1.09 is provided to allow identification and correction of a dropped or misaligned control rod. In the event such action does not correct the tilt, the margin for uncertainty on F_Q is reinstated by reducing the maximum allowed power by 3% for each percent of tilt in excess of 1.

Insert Page B 3/4 2-5

The instrumentation used in the performance of the calorimetric for the precision flow balance shall be calibrated within 7 days of performing the calorimetric.

Specification 3.2.3

Justification

See attachment 3 to this letter. Note that either the specification surveillances or the basis, not both, should be revised as shown on the preceding pages.

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TABLE 3.3-7

SEISMIC MONITORING INSTRUMENTATION

INSTRUMENTS AND SENSOR LOCATIONS	MEASUREMENT RANGE	MINIMUM INSTRUMENTS OPERABLE
1. Triaxial Peak Recording Accelerographs		
a. Radwaste Base Slab	± 1.0 g	1
b. Control Room	± 1.0 g	1
c. ESW Pump Facility	± 1.0 g	1
d. Ctmt Structure	± 2.0 g	1
e. Auxiliary Bldg. SI Pump Suctions	± 1.0 g	1
f. SGB Piping	± 2.0 g	1
g. SGB Support	± 1.0 g	1
2. Triaxial Time History and Response Spectrum Recording System, Monitoring the Following Accelerometers (Active)		
a. Ctmt. Base Slab	± 1.0 g	1
b. Ctmt. Oper. Floor	± 1.0 g	1
c. Reactor Support	± 1.0 g	1
d. Aux. Bldg. Base Slab	± 1.0 g	1
e. Aux. Bldg. Control Room Air Filters	± 1.0 g	1
f. Free Field	± 0.5 g	1
3. Triaxial Response-Spectrum Recorder (Passive)		
a. Ctmt. Base Slab	± 1.0 g	1
4. Triaxial Seismic Switches	ACCELERATION LEVEL / DIRECTION	
a. OBE Ctmt. Base Slab	~~0.12 g~~	1
b. SSE Ctmt. Base Slab	~~0.20 g~~	1
c. OBE Ctmt. Oper. Fl.	~~0.18 g~~	1
d. SSE Ctmt. Oper. Fl.	~~0.24 g~~	1
e. System Trigger	~~0.01 g~~	1

	NORTH	EAST	VERTICAL
a	0.09 g	0.09 g	0.13 g
b	0.13 g	0.14 g	0.20 g
c	0.10 g	0.10 g	0.13 g
d	0.14 g	0.16 g	0.21 g
e	0.01 g	0.01 g	0.01 g

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TABLE 4.3-8

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST
1. Radioactivity Monitors Providing Alarm and Automatic Termination of Release				
a. Liquid Radwaste Discharge Monitor (HB-RE-18)	D	P	R(2)	Q(1)
b. Steam Generator Blowdown Discharge Monitor (BM-RE-52)	D	M	R(2)	Q(1)
c. Turbine Building Drain Monitor (LE-RE-59)	D	M	R(2)	Q(1)
d. Secondary Liquid Waste System Monitor (HF-RE-45)	D	P	R(2)	Q(1)
2. Flow Rate Measurement Devices				
a. Liquid Radwaste Discharge Line	D(3)	N.A.	R	N.A.
b. Steam Generator Blowdown Discharge Line	D(3)	N.A.	R	N.A.
c. Secondary Liquid Waste System Discharge Line	D(3)	N.A.	R	N.A.
d. Combined Cooling Tower Blowdown ~~Line~~ and bypass flow	D(3)	N.A.	R	N.A.

TABLE 3.3-13

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABILITY	ACTION
1. WASTE GAS HOLDUP SYSTEM Explosive Gas Monitoring System			
a. Hydrogen Monitors	1/recombiner	**	44
b. Oxygen Monitor	2/recombiner	**	42
2. Unit Vent System			
a. Noble Gas Activity Monitor-Providing Alarm (GT-RE-21)	1	*	40
b. Iodine Sampler	1	*	43
c. Particulate Sampler	1	*	43
d. Flow Rate Monitor	1	*	39
e. Sampler Flow Rate Monitor	1	*	39
3. Containment Purge System			
~~a.~~ Noble Gas Activity Monitor - Providing Alarm and Automatic Termination of Release (GT-RE-22, GT-RE-33)	1	*	41
~~b. Iodine Sampler~~	1	*	43
~~c. Particulate Sampler~~	1	*	43
~~d. Flow Rate Monitor~~	1	*	39
~~e. Sampler Flow Rate Monitor~~	1	*	39

TABLE 4.3-9

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. WASTE GAS HOLDUP SYSTEM Explosive Gas Monitoring System					
a. Inlet Hydrogen Monitor.	D	N.A.	Q(4)	M	**
b. Outlet Hydrogen Monitor	D	N.A.	Q(4)	M	**
c. Inlet Oxygen Monitor	D	N.A.	Q(5)	M	**
d. Outlet Oxygen Monitor	D	N.A.	Q(6)	M	**
2. Unit Vent System					
a. Noble Gas Activity Monitor Providing Alarm (GT-RE-21)	D	M	R(3)	Q(2)	*
b. Iodine Sampler	W	N.A.	N.A.	N.A.	*
c. Particulate Sampler	W	N.A.	N.A.	N.A.	*
d. Flow Rate Monitor	D	N.A.	R(7)	Q	*
e. Sampler Flow Rate Monitor	D	N.A.	R	Q	*
3. Containment Purge System					
a. Noble Gas Activity Monitor - Providing Alarm and Automatic Termination of Release (GT-RE-22, GT-RE-33)	D	P	R(3)	Q(1)	*
~~b. Iodine Sampler~~	W	N.A.	N.A.	N.A.	*
~~c. Particulate Sampler~~	W	N.A.	N.A.	N.A.	*
~~d. Flow Rate Monitor~~	D	N.A.	R(7)	Q	*
~~e. Sampler Flow Rate Monitor~~	D	N.A.	R	Q	*

Specifications Tables 3.3-13 and 4.3-9

Justification

Justification for removing the iodine sampler, particulate sampler, flow rate monitor and sampler flow rate monitor from the containment purge system is as follows:

1) All four monitors obtain a sample of the containment discharge prior to filtration. These samples are therefore not representative of the iodines and particulates being discharged from the site.

2) Containment purges exhaust via the Unit Vent. The Unit Vent monitor has an iodine sampler and particulate sampler that is isokinetic. This is the sample that is representative of site discharges. The Unit Vent samplers are the ones that need to be covered by Action items 43 and 39.

CONTAINMENT SYSTEMS

INTERNAL PRESSURE

LIMITING CONDITION FOR OPERATION

3.6.1.4 Primary containment internal pressure shall be maintained between +1.5 and -~~0.1~~ psig.
-0.3

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With the containment internal pressure outside of the limits above, restore the internal pressure to within the limits within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.4 The primary containment internal pressure shall be determined to be within the limits at least once per 12 hours.

c. At least once per 18 months, or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire or chemical release in any ventilation zone communicating with the system by:

1) Verifying that the Control Room Emergency Ventilation System satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 1% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c, and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 2000 cfm ± 10% for the Filtration System and 2000 cfm ± 10% for the Pressurization System with 500 cfm ± 10% going through the Pressurization System filter adsorber unit;

2) Verifying, within 31 days after removal, that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978, for a methyl iodide penetration of less than 1%; and

3) Verifying a system flow rate of 2000 cfm ± 10% for the Filtration System and 2000 cfm ± 10% for the Pressurization System with 500 cfm ± 10% going through the Pressurization System filter adsorber unit during system operation when tested in accordance with ANSI N510-1975.

d. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal, that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978, for a methyl iodide penetration of less than 1%;

e. At least once per 18 months by:

1) Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 5.4 inches Water Gauge while operating the system at a flow rate of 2000 cfm ± 10% for the Filtration System and 500 cfm ± 10% for the Pressurization System filter adsorber unit;

2) Verifying that on a Control Room Ventilation Isolation ~~or High Smoke Density~~ test signal, the system automatically switches into a recirculation mode of operation with flow through the HEPA filters and charcoal adsorber banks;

3) Verifying that the system maintains the control room at a positive pressure of greater than or equal to 1/8 inch Water Gauge at less than or equal to a pressurization flow of 400 cfm relative to adjacent areas during system operation; and

4) Verifying that the Pressurization System filter adsorber unit heaters dissipate 15 ± 2 kW in the Pressurization System when tested in accordance with ANSI N510-1975.

Specification 4.7.6.e.2

Justification

Reference to the high smoke density test signal was deleted from this surveillance because in the SNUPPS design this signal only causes an alarm, it doesn't switch control room ventillation into the recirculation mode of operation.

JHR/mjd/1al

PLANT SYSTEMS

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3/4.7.10 FIRE SUPPRESSION SYSTEMS

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FIRE SUPPRESSION WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.10.1 The Fire Suppression Water System shall be OPERABLE with:

a. At least two fire suppression pumps, each with a capacity of 1500 gpm, with their discharge aligned to the fire suppression header;

b. Two separate water supply tanks, each with a minimum level of ~~29.5~~ 31.0 feet (~~250,000~~ 260,000 gallons); and

c. An OPERABLE flow path capable of taking suction from both fire water storage tanks and transferring the water through distribution piping with OPERABLE sectionalizing control or isolation valves to the yard hydrant curb valves, the last valve ahead of the water flow alarm device on each sprinkler or hose standpipe, and the last valve ahead of the deluge valve on each Deluge or Spray System required to be OPERABLE per Specifications 3.7.10.2, and 3.7.10.4.

APPLICABILITY: At all times.

ACTION:

a. With one of the two required pumps and/or one water supply inoperable, restore the inoperable equipment to OPERABLE status within 7 days or provide an alternate backup pump or supply. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

b. With the Fire Suppression Water System otherwise inoperable establish a backup Fire Suppression Water System within 24 hours.

SURVEILLANCE REQUIREMENTS

4.7.10.1.1 The Fire Suppression Water System shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying the water level in each fire water storage tank exceeds ~~29.5~~ 31.0 feet (~~250,000~~ 260,000 gallons),

b. At least once per 31 days on a STAGGERED TEST BASIS by starting the electric motor-driven pump and operating it for at least 15 minutes on recirculation flow,

c. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path is in its correct position, Specification 3.7.10.1.b.

Justification:

Minimum water supply tank capacity is that required to provide maximum sprinkler demand in a safety-related area (1160 gpm) plus 1000 gpm for hose streams, for a period of 2 hours. This represents a minimum tank capacity of 259,200 gallons which exceeds the current required capacity of 250,000 gallons.

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3/4.7.11 FIRE BARRIER PENETRATIONS

LIMITING CONDITION FOR OPERATION

3.7.11 All fire barrier penetrations (walls, floor/ceilings, cable tray enclosures, and other fire barriers) separating safety related fire areas or separating portions of redundant systems important to safe shutdown within a fire area and all sealing devices in fire rated assembly penetrations (fire doors; fire windows; fire dampers; cable, tray piping, and ventilation duct penetration seals) shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one or more of the above required fire barrier penetrations inoperable, within 1 hour establish a continuous fire watch on at least one side of the affected penetration, or verify the OPERABILITY of fire detectors on at least one side of the inoperable fire barrier and establish an hourly fire watch patrol.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.11.1 At least once per 18 months the above required fire rated assemblies and penetration sealing devices shall be verified OPERABLE by performing a visual inspection of:

a. The exposed surfaces of each fire rated assembly,

b. Each fire window/fire damper and associated hardware, and

c. At least 10% of each type (electrical and mechanical) of sealed penetration. If apparent changes in appearance or abnormal degradations are found, a visual inspection of an additional 10% of each type of sealed penetration shall be made. This inspection process shall continue until a 10% sample with no apparent changes in appearance or abnormal degradation is found. Samples shall be selected such that each penetration seal will be inspected every 15 years.

4.7.11.2 Each of the above required fire doors shall be verified OPERABLE by inspecting the automatic hold-open, release and closing mechanism and latches at least once per 6 months, and by verifying:

a. The OPERABILITY of the Fire Door Supervision System for each electrically supervised fire door by performing a TRIP ACTUATING DEVICE OPERATIONAL TEST at least once per 31 days,

b. That each locked closed fire door is closed at least once per 7 days,

c. That doors with automatic hold-open and release mechanisms are free of obstructions at least once per 24 hours and performing a functional test at least once per 18 months, and

d. That each unlocked fire door without electrical supervision is closed at least once per 24 hours.

Specification 3.7.11

Justification

This change is required to correct a typographical error (the closed parenthesis) and to accurately reflect the fact that cable trays, not cables, are the fire barrier penetrations.

LIMITING CONDITION FOR OPERATION

ACTION (Continued)

2. When in MODE 1, 2, or 3, the steam-driven auxiliary feedwater pump is OPERABLE.

If these conditions are not satisfied within 2 hours be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

d. With two of the above required offsite A.C. circuits inoperable, demonstrate the OPERABILITY of two diesel generators by performing Specification 4.8.1.1.3a.4) within 1 hour and at least once per 8 hours thereafter, unless the diesel generators are already operating; restore at least one of the inoperable offsite sources to OPERABLE status within 24 hours or be in at least HOT STANDBY within the next 6 hours. With only one offsite source restored, restore at least two offsite circuits to OPERABLE status within 72 hours from time of initial loss or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

e. With two of the above required diesel generators inoperable, demonstrate the OPERABILITY of two offsite A.C. circuits by performing Specification 4.8.1.1.1 within 1 hour and at least once per 8 hours thereafter; restore at least one of the inoperable diesel generators to OPERABLE status within 2 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Restore at least two diesel generators to OPERABLE status within 72 hours from time of initial loss or be in least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.8.1.1.1 Each of the above required independent circuits between the offsite transmission network and the onsite Class 1E distribution system shall be:

a. Determined OPERABLE at least once per 7 days by verifying correct breaker alignments, indicated power availability, and

See following pages marked "A"

~~b. Demonstrated OPERABLE in accordance with the OPERABILITY of the applicable Fire Detection Instrumentation (Specification 3.3.3.7) and the applicable Fire Suppression Systems (Specification 3.7.10) for the ESF transformers, XNB01 and XNB02.~~

See following pages marked "B"

~~4.8.1.1.2 The solid-state load sequencer logic shall be demonstrated OPERABLE by performing an ACTUATION LOGIC TEST and a MASTER RELAY TEST at least once per 31 days and a SLAVE RELAY TEST at least once per 92 days.~~

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A

PLANT SYSTEMS

SPRAY AND/OR SPRINKLER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.10.2 The following Spray and/or Sprinkler Systems shall be OPERABLE:

a. Wet Pipe Sprinkler Systems

Building	Elevation	Area Protected
Auxiliary	2000	North Electric Cable Chase
Auxiliary	1988/2000	South Electric Cable Chase
Control	1974 - 2073	Vertical Electrical Chases
Control	1974	Pipe Space and Tank Room
Control	1992	Cable Area Above Access Control

b. Pre-Action Sprinkler Systems

Building	Elevation	Area Protected
Auxiliary	1974	Cable Trays*
Auxiliary	2000	Cable Trays*
Auxiliary	2026	Cable Trays*
Control	2032	Lower Cable Spreading Room
Control	2073	Upper Cable Penetration Area
Reactor	2026	North Cable Penetration Area
Reactor	2026	South Cable Penetration Area
Diesel Gen. (E)	2000	East Diesel Generator Room
Diesel Gen. (W)	2000	West Diesel Generator Room

c. Water Sprays Systems

Building	Elevation	Area Protected
Auxiliary	2000	Auxiliary Feedwater Pump Turbine
ESF TRANSFORMER	GRADE	XNB01*
ESF TRANSFORMER	GRADE	XNB02*

APPLICABILITY: Whenever equipment protected by the Spray/Sprinkler System is required to be OPERABLE.

ACTION:

a. With one or more of the above required Spray and/or Sprinkler Systems inoperable, within 1 hour establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish an hourly fire watch patrol.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.10.2 Each of the above required Spray and/or Sprinkler Systems shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path is in its correct position;

*Areas contain redundant systems or components which could be damaged.

(A)

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TABLE 3.3-11 (Continued)

FIRE DETECTION INSTRUMENTS

INSTRUMENT LOCATION	ZONE	TOTAL NUMBER OF INSTRUMENTS* HEAT (x/y)	FLAME (x/y)	SMOKE (x/y)
6202-Elec. Equipment Rm.	601			3/0
6203-Air Handling Equip. Rm.	601			3/0
6301-Fuel Bldg. 2047'6" Gen. Flr.	602		2/0	
6303-Fuel Bldg. Exh. Filt. Absorb. Rm. A	601			2/0
6304-Fuel Bldg. Exh. Filt. Absorb. Rm. B	601			2/0
-North ESW Pumphouse	002			3/0
-South ESW Pumphouse	001			3/0
-ESW Cooling Tower	001			1/0
-ESW Cooling Tower	002			1/0
-ESF TRANSFORMER XNB01	016	0/6		
-ESF TRANSFORMER XNB02	017	0/6		

TABLE NOTATIONS

*(x/y): x is number of Function A (early warning fire detection and notification only) instruments.
y is number of Function B (actuation of fire suppression systems and early warning and notification) instruments.

**The fire detection instruments located within the containment are not required to be OPERABLE during the performance of Type A containment leakage rate tests.

(1) Zone is associated with a Halon-protected space. Each space has two separate detection circuits (zones). One zone, in its entirety, needs to remain operable.

(2) Line-type heat detector.

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TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
8. Loss of Power					
a. 4 kV Bus Undervoltage -Loss of Voltage	4/Bus	2/Bus	3/Bus	1, 2, 3, 4	19*
b. 4 kV Bus Undervoltage -Grid Degraded Voltage	4/Bus	2/Bus	3/Bus	1, 2, 3, 4	19*
9. Control Room Isolation					
a. Manual Initiation	2	1	2	All	18
b. Automatic Actuation Logic and Actuation Relays (SSPS)	2	1	2	All	14
c. Automatic Actuation Logic and Actuation Relays (BOP ESFAS)	2	1	2	All	14
d. Phase "A" Isolation	See Item 3.a. above for all Phase "A" Isolation initiating functions and requirements.				
10. Engineered Safety Features Actuation System Interlocks					
a. Pressurizer Pressure, P-11	3	2	2	1, 2, 3	20
b. Reactor Trip, P-4	4-2/Train	2/Train	2/Train	1, 2, 3	22
11. Solid State Load Sequencer	2-1/Train	1/Train	2-1/Train	1,2,3,4	25

(B)

TABLE 3.3-3 (Continued)

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ACTION STATEMENTS (Continued)

ACTION 18 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

ACTION 19 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 1 hour, and

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 2 hours for surveillance testing of other channels per Specification 4.3.2.1.

ACTION 20 - With less than the Minimum Number of Channels OPERABLE, within 1 hour determine by observation of the associated permissive annunciator window(s) that the interlock is in its required state for the existing plant condition, or apply Specification 3.0.3.

ACTION 21 - With the number of OPERABLE Channels one less than the Minimum Channels OPERABLE requirement, be in at least HOT STANDBY within 6 hours and in at least HOT SHUTDOWN within the following 6 hours; however, one channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.3.2.1 provided the other channel is OPERABLE.

ACTION 22 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within 6 hours and in at least HOT SHUTDOWN within the following 6 hours.

ACTION 23 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or declare the associated valve inoperable and take the ACTION required by Specification 3.7.1.5.

ACTION 24 - With the number of OPERABLE Channels one less than the Minimum Channels OPERABLE requirement, declare the affected auxiliary feedwater pump inoperable and take the ACTION required by Specification 3.7.1.2.

ACTION 25 - See insert on following page

(B)

Insert for Page 3/4 3-21

25 With the number of OPERABLE Channels one less than the Minimum Channels OPERABLE requirement, declare the affected Diesel Generator and offsite Power Source Inoperable and take the ACTION required by Specification 3.8.1.1.

(B)

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TOTAL ALLOWANCE (TA)	Z	SENSOR ERROR (S)	TRIP SETPOINT	ALLOWABLE VALUE
8. Loss of Power (Continued)					
b. 4 kV Undervoltage -Grid Degraded Voltage	N.A.	N.A.	N.A.	104.5V (120V Bus) w/119s delay	104.5+2.6,-0V (120V Bus) w/119 ± 11.6s delay
9. Control Room Isolation					
a. Manual Initiation	N.A.	N.A.	N.A.	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.	N.A.	N.A.	N.A.	N.A.
c. Automatic Actuation Logic and Actuation Relays (BOP ESFAS)	N.A.	N.A.	N.A.	N.A.	N.A.
d. Phase "A" Isolation	See Item 3.a. above for all Phase "A" Isolation Trip Setpoints and Allowable Values.				
10. Engineered Safety Features Actuation System Interlocks					
a. Pressurizer Pressure, P-11	N.A.	N.A.	N.A.	$\leq$ 1970 psig	$\leq$ 1981 psig
b. Reactor Trip, P-4	N.A.	N.A.	N.A.	N.A.	N.A.
11. Solid State Load Sequencer	N.A.	N.A	N.A.	N.A.	N.A.

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TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
8. Loss of Power (Continued)								
b. 4 kV Undervoltage-Grid Degraded Voltage	N.A.	R	N.A.	M	N.A.	N.A.	N.A.	1, 2, 3, 4
9. Control Room Isolation								
a. Manual Initiation	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	All
b. Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	Q(3)	All
c. Automatic Actuation Logic and Actuation Relays (BOP ESFAS)	N.A.	N.A.	N.A.	N.A.	M(2)	N.A.	N.A.	All
d. Phase "A" Isolation	See Item 3.a. above for all Phase "A" Isolation Surveillance Requirements.							
10. Engineered Safety Features Actuation System Interlocks								
a. Pressurizer Pressure, P-11	N.A.	R	M	N.A.	N.A.	N.A.	N.A.	1, 2, 3
b. Reactor Trip, P-4	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3
11. Solid State Load Sequencer	N.A.	N.A.	N.A	N.A.	M(1,2)	N.A.	N.A.	1,2,3,4

TABLE NOTATIONS

(1) Each train shall be tested at least every 62 days on a STAGGERED TEST BASIS.

(2) Continuity check may be excluded from the ACTUATION LOGIC TEST.

(3) Except Relays K602, K620, K622, K624, K630, K740, and K741, which shall be tested at least once per 18 months during refueling and during each COLD SHUTDOWN exceeding 24 hours unless they have been tested within the previous 90 days.

Specifications 4.8.1.1.1.b and 4.8.1.1.2

Justification

SNUPPS proposes that these surveillances be moved to the specifications to which they most logically belong. The appropriate action statement for ESFAS instrumentation has been charged according to NRC requirements.

DRAFT

SURVEILLANCE REQUIREMENTS (Continued)

2) Verifying the fuel level in the fuel storage tank,

3) Verifying the fuel transfer pump starts and transfers fuel from the storage system to the day tank,

4) Verifying the diesel starts from ambient condition and accelerates to at least 514 rpm in less than or equal to 12 seconds.* The generator voltage and frequency shall be 4000 ± ~~200~~ 320 volts and 60 ± 1.2 Hz within 12 seconds* after the start signal. The diesel generator shall be started for this test by using one of the following signals:

   a) Manual, or

   b) Simulated loss-of-offsite power by itself, or

   c) Safety Injection test signal.

5) Verifying the generator is synchronized, loaded to greater than or equal to 6201 kW at the maximum practical rate,* operates with a load greater than or equal to 6201 kW for at least 60 minutes, and

6) Verifying the diesel generator is aligned to provide standby power to the associated emergency busses.

b. At least once per 31 days and after each operation of the diesel where the period of operation was greater than or equal to 1 hour by checking for and removing accumulated water from the day tanks;

c. At least once per 31 days by checking for and removing accumulated water from the fuel oil storage tanks;

d. At least once per 92 days and from new fuel oil prior to its addition to the storage tanks by verifying that a sample obtained in accordance with ASTM-D270-1975 meets the following minimum requirements in accordance with the tests specified in ASTM-D975-1977:

   1) A water and sediment content of less than or equal to 0.05 volume percent;

   2) A kinematic viscosity of 40°C of greater than or equal to 1.9 centistokes, but less than or equal to 4.1 centistokes;

   3) A specific gravity as specified by the manufacturer at 60/60°F of greater than or equal to 0.83 but less than or equal to 0.89 or an API gravity at 60°F of greater than or equal to 27 degrees but less than or equal to 39 degrees;

* See insert, following page

INSERT

These diesel generator starts from ambient conditions shall be performed only once per 184 days in these surveillance tests and all other engine starts for the purpose of this surveillance testing shall be preceded by an engine prelube period and/or other warmup procedures recommended by the manufacturer so that the mechanical stress and wear on the diesel engine is minimized.

4) An impurity level of less than 2 mg. of insolubles per 100 ml when tested in accordance with ASTM-D2274-70; analysis shall be completed within 7 days after obtaining the sample but may be performed after the addition of new fuel oil; and

5) The other properties specified in Table 1 of ASTM-D975-1977 and Regulatory Guide 1.137, Revision 1, October 1979, Position 2.a., when tested in accordance with ASTM-D975-1977, analysis shall be completed within 14 days after obtaining the sample but may be performed after the addition of new fuel oil.

e. At least once per 18 months, during shutdown, by:

1) Subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for this class of standby service;

2) Verifying the diesel generator capability to reject a load of greater than or equal to 1352 kW (ESW pump) while maintaining voltage at 4000 ± ~~200~~ 320 volts and frequency at 60 ± 5.4 Hz;

3) Verifying the diesel generator capability to reject a load of 6201 kW without tripping. The generator voltage shall not exceed 4784 volts during and following the load rejection;

4) Simulating a loss-of-offsite power by itself, and:

a) Verifying deenergization of the emergency busses and load shedding from the emergency busses, and

b) Verifying the diesel starts on the auto-start signal, energizes the emergency busses with permanently connected loads within 12 seconds, energizes the auto-connected shutdown loads through the shutdown sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization, the steady-state voltage and frequency of the emergency busses shall be maintained at 4000 ± ~~200~~ 320 volts and 60 ± 1.2 Hz during this test.

5) Verifying that on a Safety Injection test signal without loss-of-offsite power, the diesel generator starts on the auto-start signal and operates on standby for greater than or equal to 5 minutes. The generator voltage and frequency shall be 4000 ± ~~200~~ 320 volts and 60 ± 1.2 Hz within 12 seconds after the auto-start signal; the generator steady-state generator voltage and frequency shall be maintained within these limits during this test;

6) Simulating a loss-of-offsite powe. in conjunction with a Safety Injection test signal, and

a) Verifying deenergization of th- emergency busses and load shedding from the emergency busses;

b) Verifying the diesel starts on the auto-start signal, energizes the emergency busses with permanently connected loads within 12 seconds, energizes the auto-connected emergency (accident) loads through the LOCA sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with emergency loads. After energization, the steady-state voltage and frequency of the emergency busses shall be maintained at 4000 ± ~~200~~ 320 volts and 60 ± 1.2 Hz during this test; and

c) Verifying that all automatic diesel generator trips, except high jacket coolant temperature, engine overspeed, low lube oil pressure, high crankcase pressure, start failure relay, and generator differential, are automatically bypassed upon loss of voltage on the emergency bus concurrent with a Safety Injection Actuation signal.

7) Verifying the diesel generator operates for at least 24 hours. During the first 2 hours of this test, the diesel generator shall be loaded to greater than or equal to 6821 kW and during the remaining 22 hours of this test, the diesel generator shall be loaded to greater than or equal to 6201 kW. The generator voltage and frequency shall be 4000 ± ~~200~~ 320 volts and 60 + 1.2,-3 Hz within 12 seconds after the start signal; the steady-state generator voltage and frequency shall be maintained within 4000 ± ~~200~~ 320 volts and 60 ± 1.2 Hz during this test. Within 5 minutes after completing this 24-hour test, perform Specification 4.8.1.1.2e.6)b)*;

8) Verifying that the auto-connected loads to each diesel generator do not exceed 6635 kW;

9) Verifying the diesel generator's capability to:

a) Synchronize with the offsite power source while the generator is loaded with its emergency loads upon a simulated restoration of offsite power,

b) Transfer its loads to the offsite power source, and

c) Be restored to its standby status.

10) Verifying that with the diesel generator operating in a test mode, connected to its bus, a simulated Safety Injection signal overrides the test mode by: (1) returning the diesel generator to standby operation, and (2) automatically energizing the emergency loads with offsite power;

---

*If Specification 4.8.1.1.2e.6)b) is not satisfactorily completed, it is not necessary to repeat the preceding 24-hour test. Instead the diesel generator may be operated at 6201 kW for 1 hour or until operating temperature has stabilized.

SNUPPS

SURVEILLANCE 4.8.1.1.2

Changing of the Diesel Generator starting voltage tolerance from ± 200 volts to ± 320 volts is required in order to accomodate instrument loop and meter calibration tolerances as well as diesel generator performance variations.

Utilization of 4000 volts ± 320 volts as acceptance criteria for Diesel Generator start will have no detrimental effect on the Diesel Generator or its associated components. Electrical equipment associated with the Diesel Generator includes bus, instrument transformers, relays and transducers. These components are capable of withstanding, continuously, a variation of ± 10% rated voltage. When the diesel generator breakers are closed, the emergency loads that are sequenced on step 0 are energized. These loads consist of 4000 volt class IE motors, 460 volt class IE motors and 4000/480 volt distribution transformers. All of these components are capable, by industry standards, of operating continuously with a ± 10% voltage variation at their terminals.

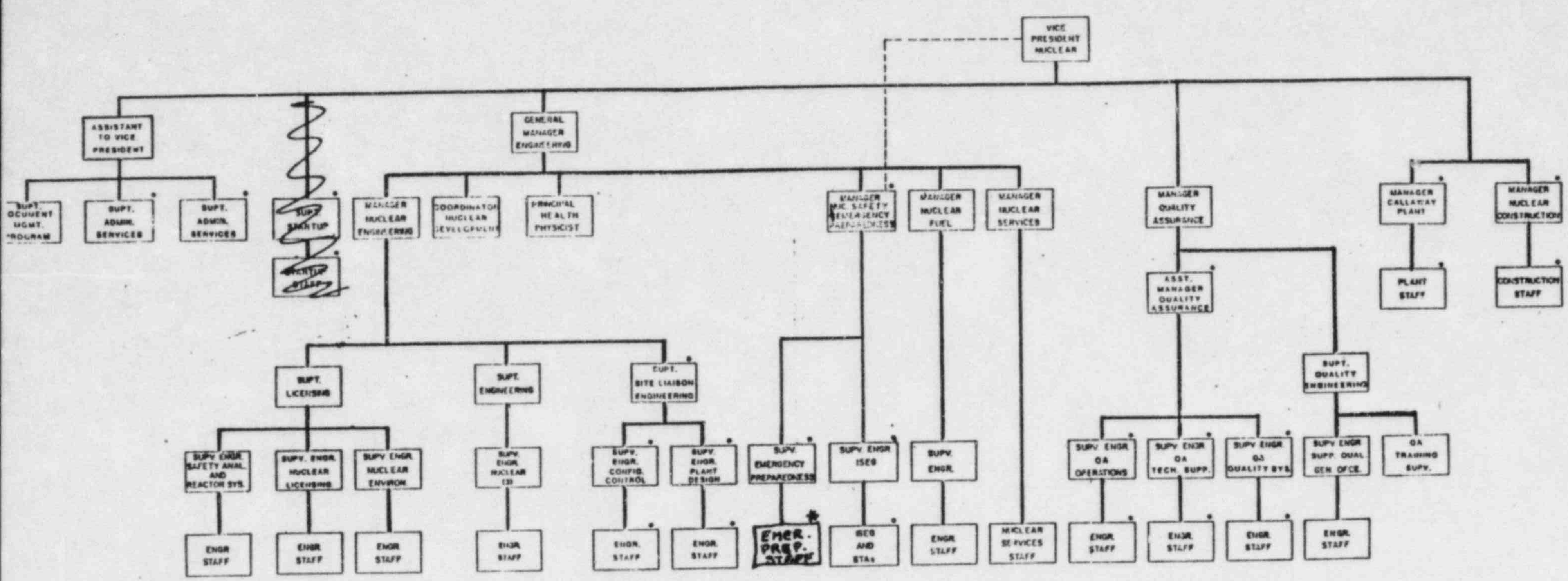
Based on these capabilities, expansion of the voltage tolerance acceptance criteria into Technical Specification section 4.8.1.1.2 remains within the design parameters of all associated components and is therefore acceptable.

TABLE 3.8-1

CONTAINMENT PENETRATION CONDUCTOR

OVERCURRENT PROTECTIVE DEVICES

PROTECTIVE DEVICE NUMBER AND LOCATION	TRIP SETPOINT (Amperes)	BREAKER RESPONSE TIME AT MAX. SHORT CIRCUIT (Sec/Cycles)	POWERED EQUIPMENT
13.8-kV SWITCHGEAR			
Primary (P) 252PA0107	3600 (50)/ 372 (51) & 840 (51)	0.1	Reactor Coolant Pump DPBB01A
P-252PA0108	3600 ~~3163~~(50)/372 (51) & 840 (51)	0.1	Reactor Coolant Pump DPBB01B
P-252PA0205	3600 ~~3163~~ (50)/372(51) & 840 (51)	0.1	Reactor Coolant Pump DPBB01C
P-252PA0204	3600 ~~3163~~ (50/372 (51) & 840 (51)	0.1	Reactor Coolant Pump DPBB01D
480-V LOAD CENTER			
P-52NG0304 B-52NG0301	1200 (Inst.) 4320 (S.T.)	0.05 0.5	Hydrogen Recombiner SGS01A
P-52NG404 B-52NG0401	1200 (Inst.) 4320 (S.T.)	0.05 0.5	Hydrogen Recombiner SGS01B
P-52PG2102 Through 52PG2112 B-350 A Fuse	375 (Inst.)	0.025 N.A.	Pressurizer Backup Heater



* LOCATED ON SITE
------ COMMUNICATION PATH

FIGURE 6.2-1
OFFSITE ORGANIZATION

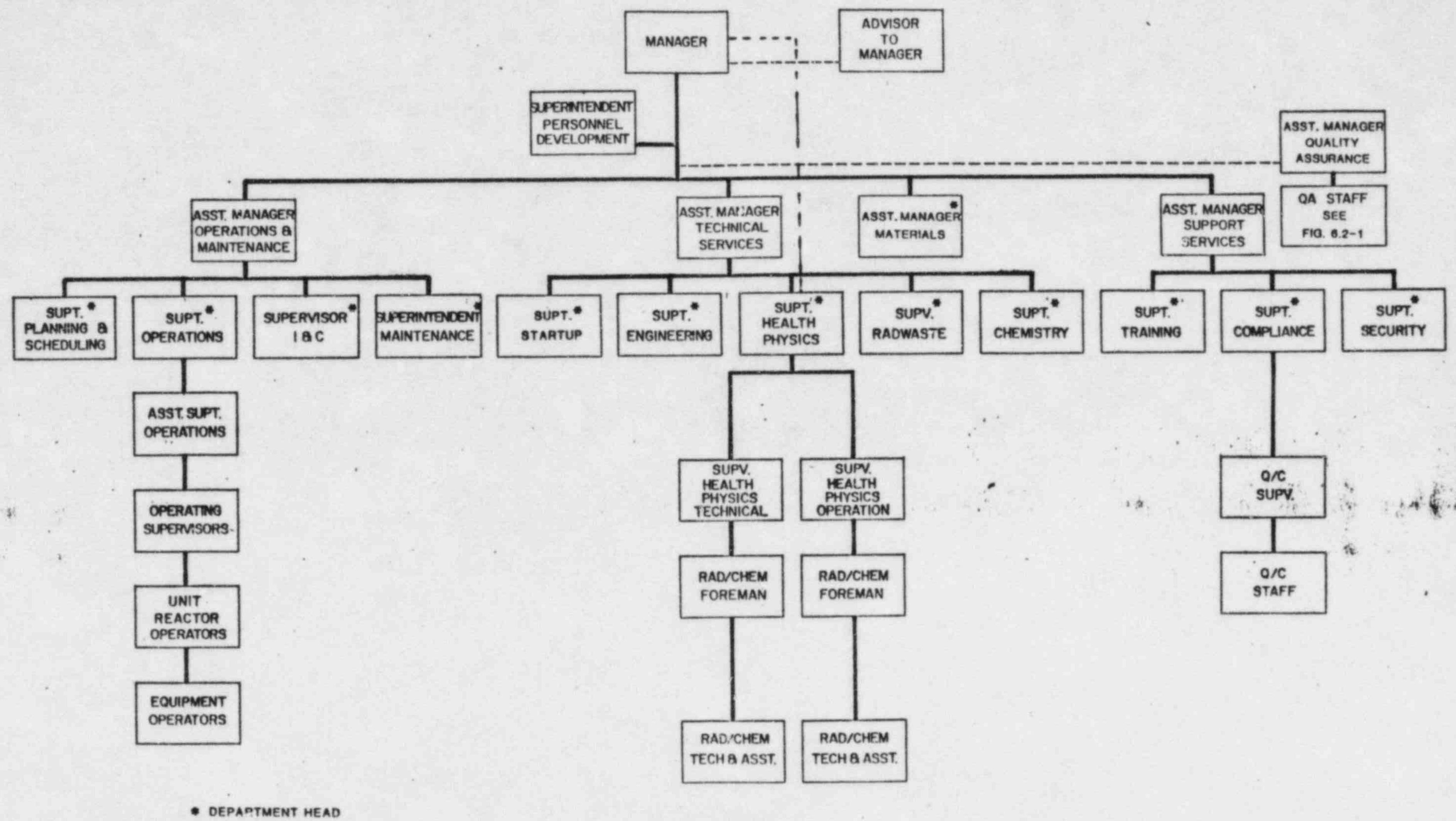


FIGURE 6.2-2

UNIT ORGANIZATION

Attachment 3

BACKGROUND INFORMATION ON THE

REQUESTED CHANGE TO SPECIFICATION 3.2.3

(RCS Flowrate and Nuclear Enthalpy
Rise Hot Channel Factor)

BACKGROUND

During a telecon with the NRC Project Manager for Callaway (J. Holonich), SNUPPS was requested to provide background information on the development of the 2% RCS flow uncertainty for Callaway. Then on March 22, 1984, the NRC forwarded a copy of an SER written for Catawba describing the following specific areas of concern:

1) The licensee shall either incorporate in its Technical Specifications a provision requiring that the measurement instruments be calibrated within seven days prior to the performance of calorimetric flow measurement or incorporate in its uncertainty analysis the drift effects of the measurement instrumentations.

2) The licensee shall institute a trending monitoring program capable of detecting feedwater venturi fouling of 0.1 percent.

3) The licensee shall identify any measurement instrumentation having an uncertainty value larger than the Westinghouse bounding value.

Responses to the above are contained herein or in the attached information from Westinghouse.

The following are Callaway's positions on the three items immediately above:

1) Since incorporation of this surveillance is a new issue, there is some confusion over whether the requirement should be listed in the bases or as part of the specification itself. Therefore, Callaway has included changes for both specification 3.2.3 and its basis, and will leave the decision as to where to include the requirement up to the NRC. In either case, Callaway's commitment is to calibrate the instrumentation used in the performance of the precision flow balance within seven days of the calorimetric. This commitment involves the instruments used for the following parameters:

   a) steam pressure
   b) feedwater pressure
   c) feedwater temperature
   d) feedwater venturi delta P

2) In order to avoid having to take the 0.1 percent uncertainty for feedwater venturi fouling, Callaway has committed to a visual inspection of the feedwater venturi every refueling to detect any buildup of fouling and correct the situation before it can affect the delta P measurement. This inspection can easily be performed through one of the handholes in the venturi itself.

3) All of the uncertainties of the instrumentation used by Callaway are bounded by the assumptions in the attached Westinghouse writeup with the exception of:

   a) steamline pressure span
   b) primary side temperature measurements performed with a DVM

Background continued

c) feedwater flow delta P cell calibration
d) feedwater flow delta P cell readout
e) feedwater enthalpy temperature uncertainty, consisting of
   (1) RTD calibration
   (2) RTD drift
   (3) DVM accuracy

As documented in the Foreward of the attached Westinghouse writeup, Westinghouse has done an evaluation of these uncertainties and determined that the changes in the parameter values have no significant impact on the final results.

Attached hereto is the Westinghouse proprietary response to the issue of RCS flow uncertainty. The proprietary material for which withholding is being requested applies to the Kansas City Power & Light Company and Kansas Gas and Electric Company's Wolf Creek Generating Station (STN 50-482) and the Union Electric Company's Callaway Plant (STN 50-483).

Enclosed are:

1. 1 copy of the Reactor Coolant System Flow Measurement Uncertainty for SNUPPS (Proprietary).

2. 1 copy of the Reactor Coolant System Flow Measurement Uncertainty for SNUPPS (Non-Proprietary).

Also enclosed are:

1. One (1) Application for Withholding (CAW-84-28). (Non-Proprietary)

2. One (1) copy of the affidavit. (Non-Proprietary)

As this submittal contains information proprietary to Westinghouse Electric Corporation, it is supported by an affidavit signed by Westinghouse, the owners of the information. The affidavit sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b) (4) of Section 2.790 of the Commission's regulations.

Accordingly, it is respectfully requested that the information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10CFR Section 2.790 of the Commission's regulations. Correspondence with respect to the proprietary aspects of this application for withholding or the supporting Westinghouse affidavit should reference CAW-84-28 and should be addressed to R. A. Weisemann, Manager Regulatory and Legislative Affairs, Westinghouse Electric Corporation, P. O. Box 355, Pittsburgh, Pennsylvania 15230.

JHR/dck2a10

ATTACHMENT 2

REACTOR COOLANT SYSTEM FLOW

MEASUREMENT UNCERTAINTY

FOR SNUPPS

FOREWORD

The following documents in a generic manner the Reactor Coolant System (RCS) Flow Measurement Uncertainty for four loop plants with RdF RTDs. The instrument uncertainties assumed normally have sufficient conservatism to envelope all plants. Base assumptions made are:

1. All measurements are made with the most accurate means reasonably available; this generally involves the use of what Westinghouse has identified as "special test instrumentation",
2. The "special test instrumentation" is calibrated no more than seven days prior to the performance of the measurement, and
3. Pressurizer pressure measurements are performed using the protection system transmitters, thus an allowance has been made for drift effects.

Based on discussions with SNUPPS and Callaway, Westinghouse understands that the above assumptions will be met. The uncertainties identified in Tables 1 and 2 are applicable with the following exceptions:

1. Steamline Pressure span is 1300 psi,
2. Primary side temperature measurements are performed with a DVM accuracy of $\pm 0.15^{\circ}F$
3. Feedwater Flow Δp cell calibration is $\pm 0.75\%$ span,
4. Feedwater Flow Δp cell readout is $\pm 0.75\%$ span, and
5. Feedwater Enthalpy temperature uncertainty consists of the following:

RTD Calibration	$\pm 0.7^{\circ}F$
RTD Drift	$\pm 0.33^{\circ}F$
DVM Accuracy	$\pm 0.5^{\circ}F$.

Westinghouse has performed an evaluation based on these exceptions and has determined that the uncertainties identified in Table 2 remain unchanged, i.e., the change in parameter values identified above have no significant impact on the final results. It is Westinghouse's judgement that the RCS Flow Calorimetric Uncertainty of $\pm 1.9\%$ flow, and Total Flow Measurement Uncertainty for Calorimetric plus one elbow tap/loop of $\pm 2.0\%$ flow are applicable to Callaway.

It has been identified to Westinghouse that only the first exception applies to Wolf Creek, thus the conclusions stated for Callaway are also applicable to Wolf Creek.

REACTOR COOLANT SYSTEM FLOW MEASUREMENT UNCERTAINTY

I. INTRODUCTION

RCS flow is monitored by the performance of a precision flow calorimetric measurement at the beginning of each cycle. The RCS loop elbow taps can then be normalized against the precision calorimetric and used for monthly surveillance (with a small increase in total uncertainty) or a precision flow calorimetric can be performed on the small surveillance schedule. The analysis presented in this report documents both measurements, i.e., the calorimetric and the elbow tap normalization uncertainties.

Since 1978 Westinghouse has been deeply involved with the development of several techniques to treat instrumentation uncertainties, errors, and allowances. The earlier versions of these techniques have been documented for several plants; one approach uses the methodology outlined in WCAP-8567 "Improved Thermal Design Procedure"[1,2,3] which is based on the conservative assumption that the uncertainties can be described with uniform probability distributions. The other approach is based on the more realistic assumption that the uncertainties can be described with normal probability distributions. This assumption is also conservative in that the "tails" of the normal distribution are in reality "chopped" at the extremes of the range, i.e., the ranges for uncertainties are finite and thus, allowing for some probability in excess of the range limits is a conservative assumption. This approach has been used to substantiate the acceptability of the protection system setpoints for several plants with a Westinghouse NSSS, e.g., D. C. Cook II[4], North Anna Unit 1, Salem Unit 2, Sequoyah Unit 1, V. C. Summer, and McGuire Unit 1. Westinghouse now believes that the latter approach can be used for the determination of the instrumentation errors and allowances for all the parameters. The total instrumentation errors presented in this response are based on this approach.

II. METHODOLOGY

The methodology used to combine the error components for a channel is basically the appropriate statistical combination of those groups of components which are statistically independant, i.e., not interactive. Those errors which are not independent are combined arithmetically to form independent groups, which can then be systematically combined. The statistical combination technique used by Westinghouse is the [ ] +a,c,e

[ ]+a,c,e of the instrumentation uncertainties. The instrumentation uncertainties are two sided distributions. The sum of both sides is equal to the range for that parameter, e.g., Rack Drift is typically [ ]+a,c, the range for this parameter is [ ]+a,c. This technique has been utilized before as noted above and has been endorsed by the staff[5,6,7] and various industry standards[8,9].

The relationship between the error components and the statistical instrumentation error allowance for a channel is defined as follows:

1. For parameter indication in the racks using a DVM;

2. For parameter indication utilizing the plant process computer;

where:

CSA	=	Channel Statistical Allowance
PMA	=	Process Measurement Accuracy
PEA	=	Primary Element Accuracy
SCA	=	Sensor Calibration Accuracy
STE	=	Sensor Temperature Effects
SPE	=	Sensor Pressure Effects
RCA	=	Rack Calibration Accuracy
RD	=	Rack Drift
RTE	=	Rack Temperature Effects
DVM	=	Digital Voltmeter Accuracy
ID	=	Computer Isolator Drift
A/D	=	Analog to Digital Conversion Accuracy

The parameters above are as defined in reference 4 and are based on SAMA standard PMC-20-1973[10]. However, for ease in understanding they are paraphrased below:

PMA - non-instrument related measurement errors, e.g., temperature stratification of a fluid in a pipe,

PEA - errors due to metering devices, e.g., elbows, venturis, orifices,

SCA - reference (calibration) accuracy for a sensor/transmitter,

SD - change in input-output relationship over a period of time at reference conditions for a sensor/transmitter,

STE - change in input-output relationship due to a change in ambient temperature for a sensor/transmitter,

SPE - change in input-output relationship due to a change in static pressure for a Δp cell,

RCA - reference (calibration) accuracy for all rack modules in loop or channel assuming the loop or channel is tuned to this accuracy. This assumption eliminates any bias that could be set up through calibration of individual modules in the loop or channel.

RD - change in input-output relationship over a period of time at reference conditions for the rack modules,

RTE - change in input-output relationship due to a change in ambient temperature for the rack modules,

DVM - the measurement accuracy of a digital voltmeter or multimeter on it's most accurate applicable range for the parameter measured,

ID - change in input-output relationship over a period of time at reference conditions for a control/protection signal isolating device,

A/D - allowance for conversion accuracy of an analog signal to a digital signal for process computer use.

A more detailed explanation of the Westinghouse methodology noting the interaction of several parameters is provided in reference 4.

III. Instrumentation Uncertainties

Current NRC Technical Specifications (11) require an RCS flow measurement with a high degree of accuracy. It is assumed for this error analysis, that this flow measurement is performed within seven days of calibrating the measurement instrumentation therefore, drift effects are not included (except where necessary due to sensor location). It is also assumed that the calorimetric flow measurement is performed at the beginning of a cycle, so no allowances have been made for feed-water venturi crud buildup.

The flow measurement is performed by determining the steam generator thermal output, corrected for the RCP heat input and the loop's share of primary system heat losses, and the enthalpy rise (Δh) of the primary coolant. Assuming that the primary and secondary sides are in equilibrium; the RCS total vessel flow is the sum of the individual primary loop flows, i.e.,

$$W_{RCS} = \sum W_L \quad \text{(Eq. 3)}$$

The individual primary loop flows are determined by correcting the thermal output of the steam generator for steam generator blowdown (if not secured), subtracting the RCP heat addition, adding the loop's share of the primary side system losses, dividing by the primary side enthalpy rise, and multiplying by the specific volume of the RCS cold leg. The equation for this calculation is:

$$W_L = \frac{(\gamma)\left\{Q_{SG} - Q_p + \left(\frac{Q_L}{N}\right)\right\}(V_C)}{(h_H - h_C)} \quad \text{(Eq. 4)}$$

where;
- W_L = Loop flow (gpm)
- γ = 0.1247 gpm/(ft^3/hr)
- Q_{SG} = Steam Generator thermal output (Btu/hr)
- Q_p = RCP heat adder (Btu/hr)
- Q_L = Primary system net heat losses (Btu/hr)
- V_C = Specific volume of the cold leg at T_C (ft^3/lb)
- N = Number of primary side loops
- h_H = Hot leg enthalpy (Btu/lb)
- h_C = Cold leg enthalpy (Btu/lb).

The thermal output of the steam generator is determined by the same calorimetric measurement as for reactor power, which is defined as:

$$Q_{SG} = (h_s - h_f)\, W_f \qquad \text{(Eq. 5)}$$

where; h_s = Steam enthalpy (Btu/lb)
h_f = Feedwater enthalpy (Btu/lb)
W_f = Feedwater flow (lb/hr).

The steam enthalpy is based on measurement of steam generator outlet steam pressure, assuming saturated conditions. The feedwater enthalpy is based on the measurement of feedwater temperature and an assumed feedwater pressure based on steamline pressure plus 100 psi. The feedwater flow is determined by multiple measurements and the same calculation as used for reactor power measurements, which is based on the following:

$$W_f = (K)\,(F_a)\left\{\sqrt{\rho_f \Delta p}\right\} \qquad \text{(Eq. 6)}$$

where; K = Feedwater venturi flow factor
F_a = Feedwater venturi correction for thermal expansion
ρ_f = Feedwater density (lb/ft^3)
Δp = Feedwater venturi pressure drop (inches H_2O).

The feedwater venturi flow coefficient is the product of a number of constants including as-built dimensions of the venturi and calibration tests performed by the vendor. The thermal expansion correction is based on the coefficient of expansion of the venturi material and the difference between feedwater temperature and calibration temperature. Feedwater density is based on the measurement of feedwater temperature and feedwater pressure. The venturi pressure drop is obtained from the output of the differential pressure cell connected to the venturi.

The RCP heat adder is determined by calculation, based on the best estimates of coolant flow, pump head, and pump hydraulic efficiency.

The primary system net heat losses are determined by calculation, considering the following system heat inputs and heat losses:

Charging flow
Letdown flow
Seal injection flow
RCP thermal barrier cooler heat removal
Pressurizer spray flow
Pressurizer surge line flow
Component insulation heat losses
Component support heat losses
CRDM heat losses.

A single calculated sum for full power operation is used for these losses/heat inputs.

The hot leg and cold leg enthalpies are based on the measurement of the hot leg temperature, cold leg temperature and the pressurizer pressure. The cold leg specific volume is based on measurement of the cold leg temperature and pressurizer pressure.

The RCS flow measurement is thus based on the following plant measurements:

Steamline pressure (P_s)
Feedwater temperature (T_f)
Feedwater pressure (P_f)
Feedwater venturi differential pressure (Δp)
Hot leg temperature (T_H)
Cold leg temperature (T_C)
Pressurizer pressure (P_p)
Steam generator blowdown (if not secured)

and on the following calculated values:

Feedwater venturi flow coefficients (K)
Feedwater venturi thermal expansion correction (F_a)
Feedwater density (ρ_f)
Feedwater enthalpy (h_f)
Steam enthalpy (h_s)
Moisture carryover (impacts h_s)
Primary system net heat losses (Q_L)

RCP heat adder (Q_p)
Hot leg enthalpy (h_H)
Cold leg enthalpy (h_C).

These measurements and calculations are presented schematically on Figure 1.

Starting off with the Equation 6 parameters, the detailed derivation of the measurement errors is noted below.

Feedwater Flow

Each of the feedwater venturis is calibrated by the vendor in a hydraulics laboratory under controlled conditions to an accuracy of [$]^{+a,b,c}$ % of span. The calibration data which substantiates this accuracy is provided for all of the plant venturis by the respective vendors. An additional uncertainty factor of [$]^{+a,c}$ % is included for installation effects, resulting in an overall flow coefficient (K) uncertainty of [$]^{+a,c}$ %. Since RCS loop flow is proportional to steam generator thermal output which is proportional to feedwater flow, the flow coefficient uncertainty is expressed as [$]^{+a,c}$ % flow.

The uncertainty applied to the feedwater venturi thermal expansion correction (F_a) is based on the uncertainties of the measured feedwater temperature and the coefficient of thermal expansion for the venturi material, usually 304 stainless steel. For this material, a change of $\pm$ 2°F in the feedwater temperature range changes F_a by [$]^{+a,b,c}$ % and the steam generator thermal output by the same amount. For this derivation, an uncertainty of [$]^{+a,c}$ in feedwater temperature was assumed (detailed breakdown for this assumption is provided in the feedwater enthalpy section). This results in a negligible impact in F_a and steam generator output.

Based on data introduced into the ASME Code, the uncertainty in F_a for 304 stainless steel is $\pm$ 5 %. This results in an additional uncertainty of [$]^{+a,c}$ % in feedwater flow. A conservative value of [$]^{+a,c}$ % is used in this analysis.

Using the ASME Steam Tables (1967) for compressed water, the effect of a [$]^{+a,c}$ error in feedwater temperature on the $\sqrt{\rho_f}$ is [$]^{+a,c}$ % in steam generator thermal output. An error of [$]^{+a,c}$ in feedwater pressure is assumed in this analysis (detailed breakdown of this value is provided in the steam enthalpy section). This results in an uncertainty in $\sqrt{\rho_f}$ of [$]^{+a,c}$ % in steam generator thermal output. The combined effect of the two results in a total $\sqrt{\rho_f}$ uncertainty of [$]^{+a,c}$ % in steam generator thermal output.

It is assumed that the Δp cell (usually a Barton or Rosemount) is read locally and soon after the Δp cell and local meter are calibrated (within 7 days of calibration). This allows the elimination of process rack and sensor drift errors from consideration. Therefore, the Δp cell errors noted in this analysis are [$]^{+a,c}$ % for calibration and [$]^{+a,c}$ % for reading error of the special high accuracy, local gauge. These two errors are in % Δp span. In order to be useable in this analysis they must be translated into % feedwater flow at full power conditions. This is accomplished by multiplying the error in % Δp span by the conversion factor noted below:

$$\left(\frac{1}{2}\right)\left(\frac{\text{span of feedwater flow transmitter in percent of nominal flow}}{100}\right)^2$$

For a feedwater flow transmitter span of [$]^{+a,c}$ % nominal flow, the conversion factor is [$]^{+a,c}$ (which is the value used in this analysis).

As noted in Table 2, the statistical sum of the errors for feedwater flow is [$]^{+a,c}$ % of steam generator thermal output.

<u>Feedwater Enthalpy</u>

The next major error component is the feedwater enthalpy used in Equation 5. For this parameter the major contributor to the error is the uncertainty in the feedwater temperature. It is assumed that the feedwater temperature is determined through the use of an RTD or thermocouple whose output is read by a digital voltmeter (DVM) or digital multimeter (DMM) (at the output of the RTD or by a Wheatstone Bridge for RTD's, or at the reference junction for thermocouples). It is also assumed that the process components of the above are calibrated within 7 days prior to the measurement allowing the elimination of drift effects for all but the RTDs. Therefore, the error breakdown for feedwater temperature is as noted on Table 1 . The statistical combination of these errors results in a total feedwater temperature error of [ ]+a,c.

Using the ASME Steam Table (1967) for compressed water, the effect of a [ ]+a,c error in feedwater temperature on the feedwater enthalpy (h_f) is [ ]+a,c % in steam generator thermal output. Assuming a [ ]+a,c error in feedwater pressure (detailed breakdown provided in the steam enthalpy section) results in a [ ]+a,c % effect in h_f and steam generator thermal output. The combined effect of the two results in a total h_f uncertainty of [ ]+a,c % steam generator thermal output, as noted on Table 2.

Steam Enthalpy

The steam enthalpy has two contributors to the calorimetric error, steamline pressure and the moisture content. For steamline pressure the error breakdown is as noted on Table 1. This results in a total instrumentation error of [ ]+a,c %, which equals [ ]+a,c for a 1200 psi span. For this analysis a conservative value of [ ] is assumed for the steamline pressure. The feedwater pressure is assumed to be 100 psi higher than the steamline pressure with a conservatively high measurement error of [ ]+a,c. If feedwater pressure is measured on the same basis as the steamline pressure (with a DVM) the error is [ ]+a,c % span, which equals [ ]+a,c for a 1500 psi span. Thus, an assumption of an error of [ ]+a,c is very conservative.

Using the ASME Steam Tables (1967) for saturated water and steam, the effect of a [ ]+a,c ([ ]+a,c) error in steamline pressure on the steam enthalpy is [ ]+a,c % in steam generator thermal output. Thus, a total instrumentation error of [ ]+a,c results in an uncertainty of [ ]+a,c % in steam generator thermal output, as noted on Table 2.

The major contributor to h_s uncertainty is moisture content. The nominal or best estimate performance level is assumed to be [ ]$^{+a,c}$ % which is the design limit to protect the high pressure turbine. The most conservative assumption that can be made in regards to maximizing steam generator thermal output is a steam moisture content of zero. This conservatism is introduced by assigning an uncertainty of [ ]$^{+a,c}$ % to the moisture content, which is equivalent through enthalpy change to [ ]$^{+a,c}$ % of thermal output. The combined effect of the steamline pressure and moisture content on the total h_s uncertainty is [ ]$^{+a,c}$ % in steam generator thermal output.

Secondary Side Loop Power

The loop power uncertainty is obtained by statistically combining all of the error components noted for the steam generator thermal output (Q_{SG}) in terms of Btu/hr. Within each loop these components are independent effects since they are independent measurements. Technically, the feedwater temperature and pressure uncertainties are common to several of the error components. However, they are treated as independent quantities because of the conservatism assumed and the arithmetic summation of their uncertainties before squaring them has no significant effect on the final result.

The only effect which tends to be dependent, affecting all loops, would be the accumulation of crud on the feedwater venturis, which can affect the Δp for a specified flow. Although it is conceivable that the crud accumulation could affect the static pressure distribution at the venturi throat pressure tap in a manner that would result in a higher flow for a specified Δp, the reduction in throat area resulting in a lower flow at the specified Δp is the stronger effect. No uncertainty has been included in the analysis for this effect. If venturi fouling is detected by the plant, the venturi should be cleaned, prior to performance of the measurement. If the venturi is not cleaned, the effect of the fouling on the determination of the feedwater flow, and thus, the steam generator power and RCS flow, should be measured and treated as a bias, i.e., the error due to venturi fouling should be added to the statistical summation of the rest of the measurement errors.

The net pump heat uncertainty is derived in the following manner. The primary system net heat losses and pump heat adder for a four loop plant are summarized as follows:

System heat losses	-2.0 MWt
Component conduction and convection losses	-1.4
Pump heat adder	+18.0
Net Heat input to RCS	+14.6 MWt

The uncertainties for these quantities are as follows: The uncertainty on systems heat losses, which is essentially all due to charging and letdown flows, has been estimated to be [ ]+a,c % of the calculated value. Since direct measurements are not possible, the uncertainty on component conduction and convection losses has been assumed to be [ ]+a,c % of the calculated value. Reactor coolant pump hydraulics are known to a relatively high confidence level, supported by the system hydraulics tests performed at Prairie Island II and by input power measurements from several plants, so the uncertainty for the pump heat adder is estimated to be [ ]+a,c % of the best estimate value. Considering these parameters as one quantity which is designated the net pump heat uncertainty, the combined uncertainties are less than [ ]+a,c % of the total, which is [ ]+a,c % of core power.

The Total Secondary Side Loop Power Uncertainty (noted in Table 2 as [ ]+a,c %) is the statistical sum of the secondary side loop power uncertainty (Q_{SG}), [ ]+a,c %, and the net pump heat addition, [ ]+a,c %.

Primary Side Enthalpy

The primary side enthalpy error contributors are T_H and T_C measurement errors and the uncertainty in pressurizer pressure. The instrumentation errors for T_H are as noted on Table 1. These errors are based on the assumption that the DVM has been recently calibrated (within 7 days prior to the measurement) and the DVM is used to read the output of the RTD, or a bridge, thus allowing the elimination of drift effects in the racks. The statistical combination of the above errors results in a total T_H uncertainty of [$]^{+a,c}$.

Table 1 also provides the instrumentation error breakdown for T_C. The errors are based on the same assumptions as for T_H, resulting in a total T_C uncertainty of [$]^{+a,c}$.

Pressurizer pressure instrumentation errors are noted on Table 1 A sensor drift allowance of [$]^{+a,c}$ % is included due to the difficulty in calibrating while at power. It is assumed calibration is performed only as required by plant Technical Specifications.

Statistically combining these errors results in the total pressurizer pressure uncertainty equaling [$]^{+a,c}$ % of span, which equals [$]^{+a,c}$ for an [$]^{+a,c}$ span. In this analysis a conservative value of [$]^{+a,c}$ is used for the instrumentation error for pressurizer pressure.

The effect of an uncertainty of [$]^{+a,c}$ in T_H on h_H is [$]^{+a,c}$ % of loop flow. Thus, an error of [$]^{+a,c}$ in T_H introduces an uncertainty of [$]^{+a,c}$ percent in h_H. An error of [$]^{+a,c}$ in T_C is worth [$]^{+a,c}$ % in h_C. Therefore, an error of [$]^{+a,c}$ in T_C results in an uncertainty of [$]^{+a,c}$ % in h_C and loop flow. An uncertainty of [$]^{+a,c}$ in pressurizer pressure introduces an error of [$]^{+a,c}$ % in h_H and [$]^{+a,c}$ % in h_C. Statistically combining the hot leg and cold leg temperature and pressure uncertainties results in an h_H uncertainty of [$]^{+a,c}$ %, an h_C uncertainty of [$]^{+a,c}$%, and a total uncertainty in Δh of [$]^{+a,c}$ % in loop flow.

Statistically combining the Total Secondary Side Loop Power Uncertainty (in Btu/hr) with the primary side enthalpy uncertainty (in Btu/lb),

TABLE 1

TYPICAL INSTRUMENTATION UNCERTAINTIES
(using RdF RTDs)

	Feedwater Pressure Indication (DVM) (1)	Feedwater Δp Indication (Local) (1)	Pressurizer Pressure Indication (DVM) (1)	Feedwater Temperature Indication (DVM) (1)	Steamline Pressure Indication (DVM) (1)	T_H Indication (DVM) (1)	T_C Indication (DVM) (1)
PMA							
PEA							
SCA							
SD							
STE							
SPE							
RCA							
RD							
RTE							
DVM							
CSA							
	1500 psi	100% Δp	800 psi	400°F	1200 psi	100°F	100°F

$^{+a,c}$

(1) % instrument span
(2) Corresponds to an accuracy of [ ] $^{+a,c}$
(3)
(4) Determined using Eq. 1
(5) Determined using Eq. 2
(6) Corresponds to an accuracy of [ ] $^{+a,c}$
(7) Corresponds to a drift of [ ] $^{+a,c}$

FIGURE 1

RCS FLOW CALORIMETRIC SCHEMATIC

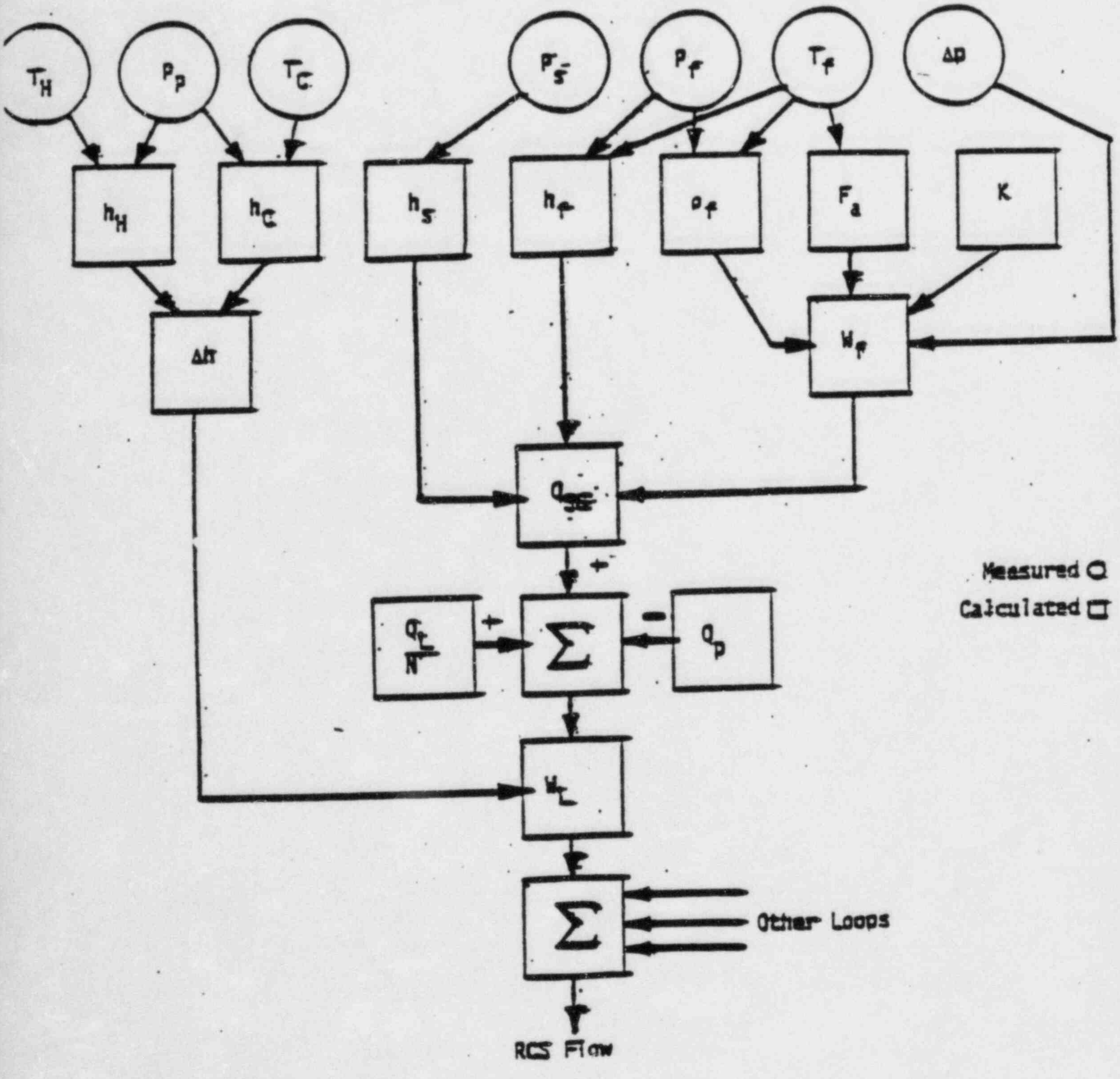


TABLE 2

CALORIMETRIC RCS FLOW MEASUREMENT UNCERTAINTIES

Component	Instrument Error(1)	Flow Uncertainty
Feedwater Flow		+a,c
Venturi, K		
Thermal Expansion Coefficient		
Temperature		
Material		
Density		
Temperature		
Pressure		
Instrumentation		
Δp Cell Calibration		
Δp Cell Gauge Readout		
Total Instrumentation Error $\sqrt{\Sigma(e)^2}$		
Total Feedwater Flow Error $\sqrt{\Sigma(e)^2}$		
Feedwater Enthalpy		
Temperature (Electronics)		
RTD Calibration		
Sensor Drift		
DVM Accuracy		
Total Temperature Error $\sqrt{\Sigma(e)^2}$		
Pressure		
Total Feedwater Enthalpy Error $\sqrt{\Sigma(e)^2}$		

TABLE 2 (Cont)

CALORIMETRIC RCS FLOW MEASUREMENT UNCERTAINTIES

Component	Instrument Error(1)	Flow Uncertainty
		+a,c
Steam Enthalpy		
Steamline Pressure (Electronics)		
Pressure Cell Calibration		
Sensor Temperature Effects		
Rack Calibration		
Rack Temperature Effects		
DVM Accuracy		
Total Electronics Error $\sqrt{\Sigma(e)^2}$		
Steamline Pressure Error Assumed -		
Moisture Carryover		
Total Steam Enthalpy Error $\sqrt{\Sigma(e)^2}$		
Secondary Side Loop Power Uncertainty $\sqrt{\Sigma(e)^2}$		
Net Pump Heat Addition Uncertainty		
Total Secondary Side Loop Power Uncertainty $\sqrt{\Sigma(e)^2}$		
Primary Side Enthalpy		
T_H (Electronics)		
RTD Calibration		
Sensor Drift		
DVM Accuracy		
T_H Instrumentation Error $\sqrt{\Sigma(e)^2}$		
T_H Temperature Streaming Error		
T_H Temperature Error $\sqrt{\Sigma(e)^2}$		

TABLE 2 (Cont)

CALORIMETRIC RCS FLOW MEASUREMENT UNCERTAINTIES

Component	Instrument Error(1)	Flow Uncertainty
		+a,c
T_C (Electronics)		
RTD Calibration		
Sensor Drift		
DVM Accuracy		
T_C Instrumentation Error $\sqrt{\Sigma(e)^2}$		
Pressurizer Pressure (Electronics)		
Pressure Cell Calibration		
Sensor Temperature Effects		
Sensor Drift		
Rack Calibration		
Rack Temperature Effects		
DVM Accuracy		
Total Pressurizer Pressure Error $\sqrt{\Sigma(e)^2}$		
Pressurizer Pressure Error Assumed		
T_H Pressure Effect		
T_H Total Error $\sqrt{\Sigma(e)^2}$		
T_C Pressure Effect		
T_C Total Error $\sqrt{\Sigma(e)^2}$		
Total Δh Uncertainty $\sqrt{\Sigma(e)^2}$		
Primary Side Loop Flow Uncertainty $\sqrt{\Sigma(e)^2}$		
Total RCS Flow Uncertainty $\sqrt{[\quad]/N}$ where N = 4 loops		

NOTES FOR TABLE 2

1. Measurements performed within 7 days after calibration thus Rack Drift, and where possible Sensor Drift, effects are not included in this analysis.

2. Conservative assumption for value, particularly if steamline pressure + 100 psi is assumed value. Uncertainty for steamline pressure noted in steam enthalpy.

3. To transform error in percent Δp span to percent of feedwater flow at 100% of nominal feedwater flow; multiply the instrument error by:

$$\left(1/2\right)\left(\frac{\text{Span of feedwater flow transmitter in percent of nominal flow}}{100}\right)^2$$

   In this analysis the feedwater flow transmitter span is assumed to be [ ]+a,c % of nominal flow.

4. Reading error for multiple readings of a Barton gauge.

5. Conservative assumption for instrumentation error for this analysis.

6. Maximum allowed moisture carryover to protect HP turbine.

7. Credit taken for the 3 tap scoop RTD bypass loop in reducing uncertainties due to temperature streaming.

8. Convoluted sum of T_H Temperature Error and T_H Pressure Effect.

9. Convoluted sum of T_C Instrumentation Error and T_C Pressure Effect.

10. Convoluted sum of T_H Total Error and T_C Total Error

results in a Primary Side Loop Flow Uncertainty of [ ]$^{+a,c}$ % loop flow. The RCS flow uncertainty is the statistical combination of the primary side loop flow error and the number of primary side loops in the plant. As noted in Table 2 the RCS Flow uncertainty for 4 loops is $\pm$1.9%flow.

NORMALIZED ELBOW TAPS FOR RCS FLOW MEASUREMENT

Based on the results of Table 2, in order for a plant to assure operation within the analysis assumptions an RCS flow calorimetric would have to be performed once every 31 EFPD. However, this is an involved procedure which requires considerable staff and setup time. Therefore, many plants perform one flow calorimetric of the beginning of the cycle and normalize the loop elbow taps. This allows the operator to quickly determine if there has been a significant reduction in loop flow on a shift basis and to avoid a long monthly procedure. The elbow taps are forced to read 1.0 in the process racks after performance of the full power flow calorimetric, thus, the elbow tap and its Δp cell are seeing normal operating conditions at the time of calibration/normalization and 1.0 corresponds to the measured loop flow at the time of the measurement.

For monthly surveillance to assure plant operation consistent with the ITDP assumptions two means of determining the RCS flow are available. One, to read the loop flows from the process computer, and two, to measure the output of the elbow tap Δp cells in the process racks with a DVM. The uncertainties for both methods and their convolution with the calorimetric uncertainty are presented below.

Assuming that only one elbow tap per loop is available to the process computer results in the following elbow tap measurement uncertainty:

	%Δp span	% flow			%Δp span	% flow	
			+a,c				+a,c
PMA				RCA			
PEA				RTE			
SCA				RD			
SPE				ID			
STE				A/D			
SD				Readout			

Δp span is converted to flow on the same basis as provided in Note 3 of Table 2 for an instrument span of [ ]$^{+a,c}$. Using Eq. 2 results in a loop uncertainty of [ ]$^{+a,c}$ flow per loop. The total uncertainty for N loops is:

$$N = 4 \left[\qquad \right]^{+a,c} \text{flow}$$

The instrument/measurement uncertainties for normalized elbow taps and the flow calorimetric are statistically independent and are 95+% probability values. Therefore, the statistical combination of the standard deviations results in the following total flow uncertainty at a 95+% probability:

4 loops ≈ ± 2.0 flow

Another method of using normalized elbow taps is to take DVM readings in the process racks of all three elbow taps for each loop. This results in average flows for each loop with a lower instrumentation uncertainty for the total RCS flow. The instrumentation uncertainties for this measurement are:

	%Δp span	% flow
PMA		
PEA		
SCA		
SPE		
STE		

+a,c

	%Δp span	% flow
SD		
RCA		
RTE		
RD		
DVM		
Readout		

+a,c

Δp span is converted to flow on the same basis as provided in Note 3 of Table 2. for an instrument span of [ ]$^{+a,c}$. Using Eq. 1 results in a channel uncertainty of [ ]$^{+a,c}$ flow. Utilizing three elbow taps (which are independent) results in a loop uncertainty of [ ]$^{+a,c}$ flow per loop. The total uncertainty for N loops is:

$$N = 4 \left[\qquad \right]^{+a,c} \text{flow}$$

The calorimetric and the above noted elbow tap uncertainties can be statistically combined as noted earlier. The 95+% probability total flow uncertainties, using three elbow taps per loop are:

4 loops ≈ ± 1.9% flow

The following table summarizes RCS flow measurement uncertainties.

TABLE 3

TOTAL FLOW MEASUREMENT UNCERTAINTIES

	Loops 4
Calorimetric uncertainty	± 1.9
Total uncertainty 3 elbow taps/loop	± 1.9
Total uncertainty 1 elbow tap/loop	± 2.0

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