PSNH

George S. Thomas
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Public Service of New Hampshire

New Hampshire Yankee Division

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SBN-938
T. F. B7.1.2

United States Nuclear Regulatory Commission
Washington, DC 20555

Attention: Mr. Vincent S. Noonan, Project Director
PWR Project Directorate #5

Reference:

(a) Construction Permits CPPR-135 and CPPR-136, Docket Nos. 50-443 and 50-444

(b) Letter from G. S. Thomas (New Hampshire Yankee) to G. W. Knighton (NRC) dated July 26, 1985, "Technical Specifications for Seabrook Station"

(c) Letter from G. S. Thomas (New Hampshire Yankee) to G. W. Knighton (NRC) dated August 23, 1985, "Supporting Analyses for Seabrook Station Technical Specifications"

(d) Letter from G. S. Thomas (New Hampshire Yankee) to V. S. Noonan (NRC) dated December 17, 1985, "Table of Risk-Based Changes Included in the Proposed Seabrook Station Technical Specifications"

(e) Letter from V. Nerses (NRC) to R. J. Harrison (PSNH) dated January 7, 1986, "Technical Specification, Request for Additional Information"

Subject: Response to Request for Additional Information Regarding Risk-Based Technical Specification Changes

Dear Sir:

Enclosed are responses to your Request for Additional Information (Reference e), questions Q1, Q3, Q6 and Q8. Response to the other questions will be submitted within 30 days.

The responses enclosed are in support of risk-based changes to Technical Specification 3.5.1.1 Accumulators, 3.5.2 ECCS Subsystems, 3.8.1.1 Electric Power Systems (offsite), and 3/4.3.4 Turbine Overspeed Protection System. An upper bound estimate of the change in risk due to these Technical Specification changes is provided in the attachment.

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P.O. Box 300 • Seabrook, NH 03874 • Telephone (603) 474-9521

The detailed analyses supporting these results are given in the enclosure to this letter. The delta risks given for Q1, Q3 and Q6 are judged to be very conservative - i.e., the best estimate of the delta risk is much smaller than the values given above. The primary source of conservation was the assumption that the mean repair time is equal to the Allowed Outage Time (AOT). This and other conservatisms are discussed in more detail in the enclosure. In addition, there are additional risk benefits gained by making the above changes that have not been quantified. These benefits have been outlined in Reference d, in the column labeled "Basis for Changes." In total, these changes are considered to have a very small and insignificant effect on the risk of core melt and an even smaller effect on public risk.

We trust that the enclosed information provides adequate response to your questions. If you require additional information, please contact Mr. Kenneth Kiper at (603) 474-9574, extension 4049.

Very truly yours,

George S. Thomas

GST:KLK:cjb

Enclosure

ATTACHMENT

SUMMARY OF RESULTS

NRC Question	System	Technical Specification Change	Upper Bound Estimate of Delta Risk*
Q1	Accumulator	Increase AOT from 1 hour to 8 hours	6.1 E-7
Q3	ECCS Subsystem	Increase AOT from 72 hours to 7 days	6.2 E-6
Q6	Electric Power (offsite)	Increase AOT from 72 hours to 7 days	3.1 E-6
Q8	Turbine Overspeed Protection	Delete specification, increase testing interval from weekly to quarterly	No change

* Delta Risk represents delta core melt frequency risk - events per reactor year

ENCLOSURE 1

Q1. NRC REQUEST:

3.5.1.a Accumulators: The request for relaxation of the allowed outage time is not adequately supported. The PSA does not even include accumulator outage in the analysis. To evaluate the probabilistic significance of this change, we need:

1. A list of sequences that are affected by accumulator outages. Each sequence should identify the events that make up the sequence and the quantification of each event. One event in each sequence would obviously be the unavailability of the accumulators.

2. Industry data on the frequency (per year) and duration of accumulator outages broken down by plant and year.

RESPONSE:

A more detailed analysis of accumulator unavailability was performed which includes the contribution for maintenance outage. (See Enclosure 2: PLG Letter Report dated 1-27-86.) This analysis is summarized below.

Data -

A data search of NPE was performed to determine an industry average for frequency of accumulator outages. (See Section 6.1 of Enclosure 2.) To summarize, a total of 105 outages was found in about 300 years of PWR operation for a median rate of 1 outage per 2.9 years of reactor operation. This rate is conservative (i.e., the best estimate would be much smaller) because most outages involved conditions only slightly out of spec for which the accumulators were still available. The values used for the duration of outage were the current and proposed Δ AOT's - 1 hour and 8 hour. This conservative assumption was made because of the difficulty in acquiring outage duration data.

Sequences -

The highest frequency core melt sequence with accumulator outage is

LLOCA * ACL = 3.17 E-7 per year

where

LLOCA is the frequency of large LOCA's = 2.03 E-4 per year

ACL is the unavailability of the accumulator system with an AOT of 1 hour = 1.56 E-3

With an AOT of 8 hours, ACL' = 4.58 E-3 and the sequence frequency is 9.30 E-7. The delta sequence frequency is 6.13 E-7. This delta is judged to be very conservative (i.e., the best estimate of the delta is much smaller) because of the assumption that the mean restoration time is equal to the AOT. While the 1 hour restoration time is only slightly conservative, the assumption of the 8 hour restoration is very conservative. Most of the outages will continue to be conditions (e.g., level, pressure, boron concentration) only slightly out of spec which can easily be restored within 1 to 2 hours. In addition, the delta value is conservative because of the conservatism in the frequency of accumulator outages, discussed above.

The next most frequent sequence involves a large LOCA initiated by a large seismic event (E0.7L). This sequence is not of importance because of its low frequency (<1.0 E-7) and because it is not sensitive to outage times of an accumulator (i.e., the seismic event results in failure of RWST or failure of RHR to start). The next non-seismic large LOCA sequence involves a turbine missile initiated LLOCA (TMLL) with a frequency of about 1.3 E-10. It is judged that the delta for 1 hour vs. 8 hours AOT for this and any other LLOCA sequences are neglibible in frequency.

Thus, the conservative estimate of the delta in core melt frequency due to changing the AOT for accumulators from 1 hour to 8 hours is 6.13 E-7.

Q2. NRC REQUEST:

3.5.5 RWST: There is no supporting documentation on RWST outages. We need the following to evaluate this request:

1. An analysis which shows that the NPSH is adequate with 431,000 gallons in the RWST when there is a switchover from injection to recirculation with all pumps running following a large LOCA.

2. Reference to an analysis that shows that 1800 ppm boron is adequate to cover the spectrum of DBA's analyzed in the FSAR.

RESPONSE:

(Later)

Q3. NRC REQUEST:

3.5.2 ECCS Subsystems: The request for relaxation of the allowed outage time is not adequately supported. To evaluate the probabilistic significant of this change, we need:

1. List of components considered in a subsystem and the frequency, duration, and type of maintenance normally performed on each component.

2. A list of sequences that are effected by the ECCS subsystem outages. Each sequence should identify the events that make up the sequence and the quantification of each event. One event in each sequence would obviously be the unavailability of the ECCS subsystems.

3. Industry data on the frequency (per year) and duration of ECCS outages broken down by plant, year, and 3 or 7 day Tech Spec AOT.

RESPONSE:

An analysis was performed of the ECCS unavailability to determine the sensitivity of a change in AOT from 72 hours to 7 days. (See Enclosure 2: PLG Letter Report dated 1-27-86). The modeling for the ECCS in this report was taken from the Seabrook Station Probabilistic Safety Assessment (SSPSA) Appendix D.8. The analysis is summarized below.

ECCS Components -

Table 1 of Enclosure 2 contains a list of the active components in the ECCS with a notation indicating how each component was treated with regard to maintenance. For these components, the type of maintenance modeled is unplanned maintenance only. No scheduled maintenance (preventive maintenance) is done on any of these components during power operation unless the maintenance can be done without affecting the operability of the components. Thus, surveillances and lubrications (e.g. topping of oil levels) are the only type of routine maintenance scheduled during operation. The major maintenance work, such as rebuilding pumps, is done infrequently and is scheduled during plant outages. Also, if a component is found to be failed, "routine" maintenance might be performed as a part of the restoration procedure. However, this is done on an unplanned basis.

Data -

The data used for frequency of maintenance outages for various components in the ECCS is discussed in Section 6.2 of Enclosure 2. The values used for duration of outages are the current and proposed AOT's - 72 hours and 7 days. This conservative assumption was used because of the difficulty in acquiring outage duration data which is better than the data developed for the SSPSA (Section 6.4).

Sequences -

A list of sequences is given in Appendix A of Enclosure 2 for each ECCS function. For each function, a delta was calculated for the difference in sequence frequency with an AOT of 72 hours and 7 days. The conservative, upper bound estimate of the delta core melt due to a change in AOT from 72 hours to 7 days for the ECCS subsystem is 6.16 E-6. This is judged to be a conservative estimate of the delta core melt (i.e., the best estimate delta would be much smaller) because of the assumption that the mean outage duration time is equal to the AOT. In addition, this delta value is dominated one top event SLRHRM, small LOCA with failure of RHR in the minimum flow recirculation path. This model is judged to be conservative because of the absence of operator action in the model, as discussed in Section 7.2 of Enclosure 2.

Q4. NRC REQUEST:

3.7.5 Ultimate Heat Sink: The request for relaxation of the allowed outage time for the cooling tower is not adequately supported. To evaluate the probabilistic significance of this change, we need:

1. A list of sequences that are affected by service water and cooling tower outages. Each sequence should identify the events that make up the sequence and the quantification of each event.

   At least two events in each sequence would cover the service water and cooling tower outages and/or failure probabilities so that the staff can modify the quantification as deemed necessary.

2. Industry data on the frequency (per year) and duration of service water and/or cooling tower outages broken down by plant, year, and AOT of 7 days.

RESPONSE:

(Later)

Q5. NRC REQUEST:

(No question)

Q6. NRC REQUEST:

3.8.1.1 Electric Power Systems: The request for relaxation of the availability of offsite power sources is not adequately supported. To evaluate the probabilistic significance of the proposed change, we need:

1. A list of sequences that are affected by the offsite power sources. Each sequence should identify the events that make up the sequence and the quantification of each event. One event in each sequence would obviously represent the unavailability of one of the offsite sources or associated onsite transformers.

2. Data on the frequency (per year) and duration of failure of offsite power sources broken down by line and year.

RESPONSE:

The following response first explains how the offsite electric power system is modeled and analyzes the affect on the system of changing the AOT from 72 hours to 7 days. Then the sequences in which failure of offsite power show up are discussed along with the effect on the system frequency due to changes in AOT. Offsite power data is discussed in general in the system analysis and is included in detail in Attachment Q6-1.

System Analysis -

The offsite power sources and offsite circuits presently consist of two 345 KV offsite transmission lines (two lines for Unit 1, three lines for Units 1 and 2), the 345 KV switchyard, two UAT's (unit auxiliary transformers) supplying power through the GSU (generator startup transformer), two RAT's (reserve auxiliary transformers) supplying power directly to the emergency busses, and the associated breakers and bus work to connect to the emergency busses. Because of the redundancy of the transformers, the Tech Spec condition (two physically independent circuits between offsite and onsite) is not entered as long as any two transformers are available. Outage of one transformer (or associated breakers or bus work) is not a Tech Spec limited condition. It is not envisioned that more than one transformer will be out at any one time while at power. Thus, Tech Spec AOT is not modeled for the transformers and associated breakers and bus work. (See the SSPSA Appendix D.2 and FSAR § 8.2 for more details of the system).

The quantification of offsite power sources and circuits is included in the initiating event LOSP (loss of station power). Losses of station power due to any and all causes (grid, transmission lines, switchyard, transformers, etc.) are included in this number. The LOSP number used in the SSPSA (0.135 events/year) was based on extensive review by PLG of historical losses of offsite power at all nuclear power plants. Since that review, a similar review of LOSP events by NSAC (documented in NSAC-80) yielded 0.088 events per site year. Because the present discussion (i.e., change in AOT from 72 hours to 7 days) is not strongly dependent on the exact value of LOSP, a general value of 0.1 events/year will be used.

The SSPSA used the LOSP as a "super component" number and did not attempt to model the offsite electrical system in any detail. For the purpose of this study, a simple model has been developed:

$$LOSP = Q_{IND} + Q_{CC}$$

where

LOSP is assumed to be 0.1 event per year with a Tech Spec AOT of 72 hours,

Q_{IND} = Q (independent failure of transmission lines) is the rate of failure of both lines within a short time period due to independent causes, i.e., the probability that the first line has failed and is down for repair when the second line fails. This quantification is based on utility data on transmission line reliability.

Q_{CC} = Q (common cause failure of offsite power sources) is the rate of failure of both lines in a short period of time due to a common cause which, presumably, is not affected by the Tech Spec AOT (i.e., not affected by the likelihood of one line being down due to maintenance). Thus, Q_{CC} is assumed to be constant with changing AOT.

The model for Q_{IND} is the following:

$$Q_{IND} = \lambda_1 \cdot (\lambda_2 \tau) + \lambda_2 \cdot (\lambda_1 \tau)$$

where

λ_1 = outage rate of line 1 (the Newington line),
λ_2 = outage rate of line 2 (the Scobie Pond Line), and
τ = mean time to restore.

Based on data from PSNH on the 345 KV transmission lines (see Attachment Q6-1), the forced outage rate is 2.05 outages per 100 circuit miles per year. The Newington line (no. 369) is about 20 miles and the Scobie Pond line (no. 363) is about 30 miles. Thus, λ_1 = 0.410 outages per year and λ_2 = 0.615 outages per year. It is assumed, for simplicity, that τ is equal to the Tech Spec AOT, i.e., 72 hours and then 7 days. This assumption is judged to be a conservative estimate of mean time to restore for the case of the 72 hour AOT (many line outages are recovered very quickly - see Attachment Q6-1). The assumption for the 7 day AOT is very conservative - i.e., the restoration time is not expected to change drastically with the additional allowed outage time.

For τ = 72 hours,

Q_{IND} = 0.0041 loses of offsite power due to independent transmission line failures per year

With LOSP = 0.1, Q_{CC} = 0.0959 common cause losses of offsite power per year.

Thus, if a LOSP occurs at Seabrook with the same frequency as the national average, it is very likely (about 96 chance out of 100) that the loss is due to common causes (e.g., weather, human error).

In support of this conclusion, the LOSP data reported in NSAC-80 was studied to determine how many of the LOSP's were due to independent vs. dependent failures. Of the 47 events in 533 site years, no more than 4 events involved independent failures (e.g., one line down for maintenance, other breaker was inadvertantly opened). This gives an independent LOSP rate of 0.0075 events per year or about 1 out of 10 LOSP's. While this is a factor of 2 larger than the Seabrook number, the conclusion is the same - that if a LOSP occurs, it is most likely due to common cause failures. The independent failure rate is smaller at Seabrook due to presumably more reliable 345 KV transmission lines than the national average. In fact, the 345 KV grid that Seabrook is connected to has never suffered a total grid unavailability. The general conclusion that common cause failures dominate LOSP is understandable based on the interdependence of the offsite grid. While the incoming circuits are physically independent, the lines are influenced by the dependencies at the grid side and on the plant side.

For τ = 7 days and assuming the same common cause contribution (Q_{CC}),

$$\begin{aligned} LOSP' &= Q_{IND}' + Q_{CC} \\ &= 0.0097 + 0.0959 = 0.1056 \end{aligned}$$

where

LOSP' is the new rate of loss of station power assuming a 7 day AOT, and

Q_{IND}' is the new rate failure of both lines within a short time period due to independent cases, assuming a 7 day AOT.

Thus, the change in LOSP initiating event frequency is about 5.6% when the AOT is increased from 72 hours to 7 days.

Sequence Analysis -

(See Report No. PLG-0431 "Risk Based Evaluation of Technical Specifications for Seabrook Station," dated August 1985, Section 5, for details of the accident squences.)

There are several types of sequences which include loss of station power: the station blackout sequences - loss of all A.C. (e.g., sequence 7D-1) and general transient sequences (e.g., sequence 4A-5). The station blackout sequences are much higher in frequency (7D-1/4A-5 = 100). Station blackout sequences can be divided between sequences initiated with a "normal" LOSP and sequences intiated with an "external event" (e.g., seismic, fire or flood in turbine building). External events are excluded from this analysis because they are in general common cause initiators and the sequences would not be affected by a line out for maintenance. Also, station blackout sequences can be divided between early and late core melt.

The late core melt/station blackout sequences are discussed first:

7D-1: LOSP * GA1 * GBA * NEF2 * ER1 = 3.40 E-5 per year

where

LOSP = loss of station power initiating event
GA1 = failure of diesel A
GBA = failure of diesel B given diesel A failure
NEF2 = no failure (i.e., success) of emergency feedwater (EFW)
ER1 = failure to recover electric power before core melt.

This sequence leads to core uncovery and melt due to loss of RCP seal cooling which causes a RCP seal LOCA and no means to makeup primary inventory. Successful EFW (turbine driven EFW pump) delays the core melt and allows additional time to recover electric power.

There are similar sequences (station blackout sequences) such as failure of service water system causing failure of diesel generators (due to no cooling) e.g., sequence 7D-2. However, these sequences are much lower in frequency. All similar sequences with frequency greater than 1 E-7 (7D-1, 7D-2, 7D-3, 7D-4, 7D-9, 7D-11, 7D-14, 7D-15) sum to 4.90 E-5. With a 5.6% increase in LOSP frequency due to change of AOT from 72 hours to 7 days, the frequency increases to 5.17 E-5 or a delta of 2.7 E-6. This delta is believed to be very conservative as discussed below.

The early core melt/station blackout sequences are characterized by the following sequence:

3D-2: LOSP * GA1 * GBA * EF2 * ER2 * FR1 = 2.21 E-6 per year

where

EF2 = failure of emergency feedwater
ER2 = failure to recover electric power before core melt
FR1 = failure to recover emergency feedwater before core melt.

This sequence is similar to the station blackout sequences discussed above except that the turbine driven EFW pump has also failed. This leads to earlier core melt and thus less time to recover electric power. All similar sequences with a frequency greater than 1 E-7 (3D-2, 3D-3, 3D-4, 3D-8, 3D-10, 3D-11, 3D-17, 3D-18) sum to 5.6 E-6. With a 5.6% increase in frequency of LOSP due to change in AOT, the frequency increased to 5.9 E-6 or a delta of 3 E-7.

Finally, LOSP also appears in squences as a general transient:

4A-5: LOSP * NGA1 * NGB1 * EFB * OR5 * ERA * FR1 = 3.3 E-7 per year

where

NGA1 = success of diesel generator A
NGB1 = success of diesel generator B
EFB = failure of emergency feedwater system
OR5 = failure of operator action to initiate feed and bleed operation
ERA = failure to recover offsite electric power before core melt
FR1 = failure to recover EFW.

This sequence involves failure of secondary cooling (EFW) and failure of primary cooling (feed and bleed) with failure of recovery actions. All similar sequences with a frequency greater than 1 E-7 (4A-5, 4A-6, 4A-7, 4A-12, 4A-13, 4A-14, 4A-15) sum to 2.0 E-6. With an increase in LOSP frequency of 5.6%, the frequency increases to 2.1 E-6 or a delta of 1 E-7.

Summing up the three delta's yields a delta frequency of 3.1 E-6 for LOSP events with a 72 hour vs. 7 day AOT. While this delta is relatively small, it is believed that this far overestimates the true change in core melt frequency. The main assumption contributing to this conservatism is that the outage duration is equal to the AOT. This conservatism increases the importance of independent line failures and also increases the change in outage time.

Attachment Q6-1

FORCED OUTAGE DATA FOR PSNH 345 KV TRANSMISSION LINES

The attached letters summarize the data for forced outages for all 345 KV transmission lines which have at least one terminal under PSNH control. This data is representative of the transmission lines connecting Seabrook to the grid (line no. 369 connecting Seabrook with Newington and line no. 363 connecting Seabrook with Scobie Pond substation).

To summarize this data, a total forced outage rate of 2.05 outages per 100 circuit miles per year was calculated from the data for the period December 4, 1972, to June 30, 1985, with a total of 3762 circuit mile years. Approximately half of the outages lasted longer than 1 hour; 15% lasted longer than 10 hours. Only 4 of the 106 outages exceeded 72 hours, including 2 at Seabrook. (The Seabrook lines are supplying power to the site rather than distributing power so the incentive to restore the lines was not as great as will be during operation.) The mean outage time was about 8 hours.

PSNH

Public Service of New Hampshire

August 1, 1985

Mr. George Tsouderos
Yankee Atomic Electric Company
1671 Worcester Road
Framingham, Mass. 01701

Dear George:

As indicated in J. A. S. Breton's letter of July 29, 1985, I have recalculated the forced outage experience for 345 KV transmission which has at least one terminal under PSNH control. 345 KV transmission can and usually does experience high trip out rates during its early operation. I have, as was done in past calculations, therefore eliminated the first two years of outages for each line. This information should be more reflective of Seabrook transmission outage rates as that will have been in operation for 2 1/2 - 5 1/2 years prior to commercial operation of Seabrook.

The lightning design for these lines and for the Seabrook associated transmission is one outage/100 circuit miles/year. Insulation coordination for Seabrook transmission will be equal or better to that used historically in PSNH 345 KV transmission design. For perspective, I have also time differenciated the forced outage rates.

Data: 12/4/72 - 6/30/85 (3761.7 circuit mile years)

Source: PSNH E-SCC (J. A. S. Breton 7/29/85 memo)

ALL OUTAGES

Clearance Related Problems	.40	Outages/100 Circuit Miles/Year
Relay Related Problems	.58	"
Lightning and Unknown Problems	.51	"
All Other Problems	.56	"
Total Forced Outages	2.05	Outages/100 Circuit Miles/year

OUTAGES OF GREATER THAN 5 MINUTES DURATION

Clearance Related Problems	.32	Outages/100 Circuit Miles/Year
Relay Related Problems	.45	"
Lightning and Unknown Problems	.24	"
All Other Problems	.53	"
Total Forced Outages	1.54	Outages/100 Circuit Miles/Year

OUTAGES OF GREATER THAN 1 HOUR DURATION

Clearance Related Problems	.19	Outages/100 Circuit Miles/Year
Relay Related Problems	.27	"
Lightning and Unknown Problems	.13	"
All Other Problems	.45	"
Total Forced Outages	1.04	Outages/100 Circuit Miles/Year

OUTAGES OF GREATER THAN 3 HOURS DURATION

Clearance Related Problems	.08	Outages/100 Circuit Miles/Year
Relay Related Problems	.11	"
Lightning and Unknown Problems	.05	"
All Other Problems	.43	"
Total Forced Outages	.67	Outages/100 Circuit Miles/Year

OUTAGES OF GREATER THAN 10 HOURS DURATION

Clearance Related Problems	.00	Outages/100 Circuit Miles/Year
Relay Related Problems	.05	"
Lightning and Unknown Problems	.03	"
All Other Problems	.24	"
Total Forced Outages	.32	Outages/100 Circuit Miles/Year

If you require clarification or any additional information, please do not hesitate to contact me.

Very truly yours,

M. D. Cannata, Jr.
Director
Power Supply/Energy Management

MDC:jlm

PSNH

Public Service of New Hampshire

July 29, 1985

Mr. George Tsouderos
Yankee Atomic Electric Company
1671 Worcester Road
Farmingham, MA 01701

Reference: SBP-85-465
T.F.J16.2.99

Dear George:

Based on PSNHs historical data, it appears that approximately eight hours would be the average time required to return a 345 KV line to service following a permanent outage including catastrophic failures and equipment not restored until convenient hours. Since December 1970 through June 1985, we have experienced one hundred eight 345 KV system line or terminal outages for a total duration of 1,832.5 hours. Two of the 108 outages involve the 369 Seabrook terminal listed below.

Four outages exceeding seventy-two hours have been experienced on the 345 KV system. Two of these outages resulted from bus faults in the Seabrook Station SF6 insulated bus. The other outages were on the 326 line:

326 line 1/31/82 to 2/5/82 - bushing failure - 116.63 hours.
326 line 6/20/75 to 6/27/75 - interrupter lead failure - 176.87 hours.
369 line terminal Seabrook 10/28/83 to 11/18/83 - "B" phase fault - 493.33 hours.
369 line terminal Seabrook 2/2/85 to 2/23/85 - "B" phase fault - 521.32 hours.

Mike Cannata is preparing a revised forced outage rate up to June, 1985.

If I can be of any assistance, please call.

Sincerely,

Joseph A.S. Breton

Joseph A.S. Breton
Superintendent
Power Supply Department

JASB/csg
05:16

Attachments

cc: R.S. Johnson

SUMMARY OF 345 KV SYSTEM OUTAGES

LINE	# OF INTERRUPTIONS	TOTAL DURATION
307	22	111.76
326	35	446.89
363	3	11.71
369	5(2)	114.13(1128.75)
373	6	3.22
379	9	7.4
385	5	7.26
391	21	115.53
	106	817.90@

Average outage time = $\frac{817.90}{106}$ = 7.8 hours

@ Does not include two 369 line terminal outages at Seabrook Station (10/28/83 and 2/02/85).

LINE OUTAGE SUMMARY

LINE = 391 COMMERCIAL DATE = December 6, 1970 LENGTH (miles) 94.22
SCOBIE TO POWNAL

DATE	T = TERMINAL L = LINE	CAUSE	DURATION
12/15/70	L	False relay operation	9.07
1/29/71	L	False transfer trip relay operation.	1.75
5/11/71	L	Damaged insulator.	9.47
5/14/71	L	Unknown.	9.32
5/15/71	L	Unknown.	4.9
5/18/71	L	Flashover to adjacent line static wire.	5.1
5/29/71	L	Switchboard work at Buxton.	1.95
5/30/71	L	Unknown.	2.1
6/06/71	L	Unknown.	2.0
6/08/71	L	False transfer trip relay operation.	.58
6/10/71	L	Relay work at Pownal.	.42
6/14/71	T	False relay operation.	2.13
6/21/71	L	Unknown.	1.57
10/09/71	L	Unknown.	.07
5/11/75	L	False breaker failure relay operation.	55.18
6/21/75	L	Unknown.	.12
6/23/75	L	Relay malfunction.	2.70
11/03/77	L	Stuck breaker.	.52
		TOTALS: 18 outages.	108.95 HRS.

LINE OUTAGE SUMMARY

LINE = 391 COMMERCIAL DATE = August 15, 1978 LENGTH (miles) = 67.72
SCOBIE TO BUXTON

DATE	T = TERMINAL L = LINE	CAUSE	DURATION
7/20/83	L	Phase wire down.	6.35
8/05/83	T	Wiring work in breaker compartment.	Momentary
		TOTALS: 2 outages.	6.35 HRS

LINE OUTAGE SUMMARY

LINE = 385 COMMERCIAL DATE = December 29, 1971 LENGTH (miles) = 105.4
SCOBIE TO MAINE YANKEE

DATE	T = TERMINAL L = LINE	CAUSE	DURATION
6/09/75	L	Failed coupling capacitor at Maine Yankee and MOAB 3J-85 would not close.	6.08
3/23/77	L	Heavy wet snow.	.15
		TOTALS: 2 outages.	6.23 HRS

LINE OUTAGE SUMMARY

LINE = 385 COMMERCIAL DATE = August 10, 1978 LENGTH (miles) 49.15
SCOBIE TO BUXTON

DATE	T = TERMINAL L = LINE	CAUSE	DURATION
1/09/79	T	Unknown.	.10
10/29/79	L	Relay work.	.88
9/14/80	L	Lightning.	.05
		TOTALS: 3 outages.	1.03 HRS

LINE OUTAGE SUMMARY

LINE = 379 COMMERCIAL DATE = December 20, 1970 LENGTH (miles) = 68.11

DATE	T = TERMINAL L = LINE	CAUSE	DURATION
5/16/71	L	Unknown.	1.23
6/25/71	L	Construction crane.	.58
12/08/71	L	Relay failure.	.88
11/25/74	L	Relay work at Vermont Yankee	.78
5/11/75	T	False breaker failure relay operation	2.12
5/24/77	L	Tree.	1.65
5/18/81	L	Relay testing.	.10
1/11/85	T	Unknown.	.03
		TOTALS: 8 outages.	7.37 HRS.

LINE OUTAGE SUMMARY

LINE = 373 COMMERCIAL DATE = July 28, 1973 LENGTH (miles) = 18.63

DATE	T = TERMINAL L = LINE	CAUSE	DURATION
4/02/76	L	Unknown.	.82
6/22/76	T	Relay failure.	.13
7/12/76	T	Unknown.	.02
7/15/77	L	Tree.	2.2
11/17/78	T	Relay testing error.	.02
1/11/85	T	Unknown.	.03
		TOTALS: 6 outages.	3.22 HRS.

LINE OUTAGE SUMMARY

LINE = 369   COMMERCIAL DATE = December 15, 1980   LENGTH (miles) = 17.16

DATE	T = TERMINAL L = LINE	CAUSE	DURATION
4/08/82	T	Low gas pressure at Seabrook	.57
7/10/82	L	Kite string across conductors	.25
7/07/83	T	Lockout relay operation.	64.28
10/28/83	L	Seabrook bus fault.	493.33
7/03/84	L	Lightning and Seabrook cable fault.	41.33
1/14/85	L	Low gas pressure at Seabrook.	7.7
2/02/85	L	Seabrook bus fault.	521.32
		TOTAL: 7 outages.	1128.78 HRS.

LINE OUTAGE SUMMARY

LINE = 363 COMMERCIAL DATE = December 13, 1983 LENGTH (miles) = 29.89

DATE	T = TERMINAL L = LINE	CAUSE	DURATION
3/01/84	T	Gas leak at Seabrook.	.18
12/05/84	T	Low gas pressure at Seabrook.	9.0
1/25/85	T	Insulator failure.	2.53
		TOTAL: 3 outages.	11.71 HRS

LINE OUTAGE SUMMARY

LINE = 307 COMMERCIAL DATE = March 29, 1974 LENGTH (miles) = 25.58

DATE	T = TERMINAL L = LINE	CAUSE	DURATION
8/02/74	L	Unknown.	.48
8/12/74	L	Unknown.	.25
6/09/75	L	Breaker failure relay cleared bus and MOAB 3J-85 would not close.	.43
3/23/77	L	Heavy wet snow and high winds.	.15
3/23/77	L	Heavy wet snow.	5.5
7/15/77	L	Trees.	2.2
7/20/77	L	Trees.	1.43
7/09/78	L	Lightning.	1.2
8/01/78	L	Unknown.	1.73
8/19/78	L	Unknown.	1.52
10/29/79	L	Relay work in progress.	2.58
2/19/81	T	Inadvertent breaker failure relay operation during rewiring.	.12
11/29/81	L	D.C. supply to system #1 relaying interrupted.	1.05
11/07/81	L	Failed lightning arrestor.	24.0
1/19/82	T	Los gas pressure at Seabrook.	53.93
1/22/84	T	Low gas pressure at Seabrook.	5.0
5/01/84	T	Telephone company investigating transfer trip circuit.	.98
7/10/84	T	Low gas pressure at Seabrook.	.20
9/21/84	T	Gas pressure sensor isolated.	.07
1/14/85	T	Low gas pressure at Seabrook.	7.45
1/16/85	T	Relay operated by microwave noise.	
NOTE: The following outage occurred prior to the line's commerical date.			
2/15/74	T	Switching error.	.47
		TOTAL: 22 outages.	110.74 HRS

LINE OUTAGE SUMMARY

LINE = 326 COMMERICAL DATE = December 4, 1970 LENGTH (miles) = 30.5

DATE	T = TERMINAL L = LINE	CAUSE	DURATION
2/28/71	L	Tree.	24.47
8/26/71	L	Unknown.	.88
9/02/72	L	Unknown.	.13
6/12/73	T	Unknown.	.12
8/31/73	L	Lightning.	.03
9/08/73	L	Unknown.	.03
5/10/74	L	Line fault.	7.87
6/15/74	L	Tree.	.32
7/02/74	L	Tree.	.13
9/11/74	L	Unknown.	4.75
11/25/74	T	Relay testing error at Vermont Yankee	.43
2/04/75	T	Relay work at Sandy Pond	5.67
5/11/75	T	False breaker failure relay operation.	2.9
6/01/75	T	Scobie Pond reactor breaker fire.	8.75
6/20/75	T	Air blast breaker failure at Scobie	176.87
8/01/75	L	Tree	.08
9/29/75	L	Unknown.	Momentary
4/13/76	L	Stuck breaker at Sandy Pond	.17
5/10/77	T	Unknown.	Momentary
5/24/77	T	Tree.	Momentary
11/03/77	L	Stuck breaker at Scobie Pond	8.18
2/19/78	L	Insulator failure.	18.3
6/11/79	L	Tree.	8.73
6/18/79	T	Tree.	.48
8/01/79	T	Lightning.	Momentary

LINE = 326 COMMERCIAL DATE = December 4, 1970 LENGTH (miles) = 30.5

DATE	T = TERMINAL : L = LINE	CAUSE	DURATION
8/10/79	L	Lightning.	Momentary
1/02/80	L	Faulty directional distance relay.	3.13
5/18/81	L	Inadvertent breaker failure relay operation during relay testing.	.05
1/28/82	L	Insulator failure.	1.78
1/31/82	L	Bushing failure.	116.63
1/30/83	T	Insulator failure.	33.2
5/25/83	L	Wire thrown across phase.	Momentary
8/04/83	T	Wiring work in breaker compartment.	.07
11/25/84	L	Relay testing at Sandy Pond.	.02
3/09/85	L	Conductor separated by gunfire.	22.72
		TOTAL: 35 outages.	446.89 HRS

Q7. NRC REQUEST:

3.8.1.1 Electric Power Systems: The request for relaxed testing schedule for diesel generators refers to Generic Letter 84-15 as a basis for the change. Also cited in this Generic Letter is a need for a reliability assurance program to maintain and improve the reliability of DGs. Provide a description of the reliability program you will implement in consideration of Generic Letter 84-15.

RESPONSE:

(Later)

Q8. NRC REQUEST:

3/4.3.4 Turbine Overspeed Protection System: Provide copy of the nuclear power experience with the turbine valves and overspeed protection system that was cited in your evaluation of the Technical Specifications for the Turbine Overspeed Protection System.

RESPONSE:

A listing of industry data on turbine valves and the overspeed protection system is provided in Tables Q8-1, Q8-2, and Q8-3. This data is summarized below.

In the evaluation of Tech Spec 3/4.3.4, Turbine Overspeed Protection System, a data review was performed. The publication Nuclear Power Experience (NPE) by Petroleum Information Corporation was reviewed to identify failures or problems with turbine valves and the overspeed protection system for the reporting period between 1967 and 1981. Failures of the turbine valves and control systems have been identified, but no overspeed protection system failure on demand event has been identified in NPE.

Among the over four hundred reported events that were reviewed relating to the turbine, 17 were turbine valves failure to fast-close on demand (see Table Q8-1). None of these challenged the operation of the emergency overspeed trip system before the plants returned to stable conditions. Five events involved control valves failure due to failure of their fast-acting solenoid valves (four of the events occurred at one plant in 1976). However, it is most likely that if the emergency overspeed trip was challenged, it would have closed these valves independent of the fast-acting solenoid. The failure mechanism of the remaining 12 events were valve binding due to steam cutting of the shaft seal and misalignment of the shaft, valve sticky operation due to build up of phosphate derivatives, valve bolt failure, and other hardware failures.

The most commonly occurring problems with the electro-hydraulic controls (EHC) of the overspeed protection system (see Table Q8-2) include foreign material in the hydraulic fluid system, leakage in the hydraulic fluid system, and EHC System spurious actuation due to faulty electronic cards or electrical components. The major concern here is the existence of foreign material in the hydraulic fluid system since this could result in common cause failure of the overspeed protection system.

A total of 5 reported emergency trip events (i.e., demands on the overspeed protection system) were found (see Table Q8-3). All overspeed protection systems functioned properly and there were no turbine failures associated with these events. However, after one of these events, damage was found on the last stage wheel believed to be from a foreign object left in the turbine.

Table Q8-1

TURBINE VALVES FAILURE TO FAST-CLOSE ON DEMAND

PLANT	DATE	NPE	CAUSE
Connecticut Yankee	9-72	PWRVI.A.16	Stop valves - steam cutting.
Connecticut Yankee	11-72	PWRVI.A.18	Stop valves - leakage/deposits.
Robinson	5-74	PWRVI.A.35	Stop valves - phosphate derivatives. (2 failures)
Turkey Point 3	5-74	PWRVI.A.36	Stop valves - phosphate buildup. (all 4 stop valves)
Turkey Point 4	12-74	PWRVI.A.44	Control valves - bolt failure.
Kewaunee	4-79	PWRVI.A.69	Stop valves - puller mechanism.
Hatch 1	2-76	BWRIX.D.40	Control valves - fast acting solenoid valve on CV exercise.
Dresden 2	7-78	BWRIX.D.54	Control valves - fast acting solenoid valve. (electrical terminal lug)
Fitzpatrick	6-75	BWRVI.A.24	Stop valves - flange ring nut broke loose and lodged between valve follower area and the hydraulic operating cylinder.
Hatch 1	7-76	BWRVI.A.30	Control valves - fast closing solenoid valves sluggish operation (closure time > 30 ms). (3 failures)
Maine Yankee	1-73	PWRIX.D.10	Governor (control) valve spring retaining bolt failed, spring separated from the valve.
Peach Bottom 2	3-77	BWRVI.A.39	CIV #5 stuck in the 85% open position while being tested. Servo valve replaced. An inspection revealed a badly scored hydraulic actuator cylinder.

Table Q8-2

PROBLEMS WITH THE ELECTROHYDRAULIC CONTROLS OF THE TURBINE OVERSPEED PROTECTION SYSTEM

PLANT	NPE	CAUSE
Davis Besse 1	PWRVI.A.66	Trip mechanism did not operate, servo valve on #2 control valve had a defective connector. (2 failures)
San Onofre 1	PWRIX.D.3	Drift in sensor set point. (2 failures)
Ginna 1	PWRIX.D.44	Control wiring shorted due to vibration-caused insulation wear out.
ANO 1	PWRIX.D.64	Faulty electronic card.
TMI 1	PWRIX.D.67	Control power UV relay in EHC failed.
Cook 1	PWRIX.D.73	Failed o-ring, large leak caused loss of EHC control function, leak required turbine trip. (3 failures)
Trojan	PWRIX.D.140	Problem with speed control unit.
Robinson 2	PWRIX.D.169	EHC oil leak.
Cook 2	PWRIX.D.202	Leak in EHC cooler.
Sequoyah	PWRIX.D.227	EHC actuated at sensing static noise in control circuitry.
Oyster Creek 1	BWRIX.D.4	Foreign materials in EHC. (3 failures)
Peach Bottom 3	BWRIX.D.33	EHC acceleration amplifier out of calibration which caused unsatisfactory valve operations.
Quad Cities 2	BWRIX.D.42	EHC fluid leak onto cable trays.
Browns Ferry 2	BWRIX.D.45	EHC pressure switch plugged failing to give a half scram when tested.
Cooper	BWRIX.D.71	EHC spurious action.
Peach Bottom 2	BWRVI.A.39	EHC leaking caused #5 CIV to close inadvertently while #2 is being tested in the closed position. This caused turbine trip and reactor scram.

Table Q8-2

(Continued)

PROBLEMS WITH THE ELECTROHYDRAULIC CONTROLS OF
THE TURBINE OVERSPEED PROTECTION SYSTEM

PLANT	NPE	CAUSE
Peach Bottom 2	BWRVI.A.40	EHC cooler leak caused contamination of hydraulic fluid. No. 3 CV failed to open causing a reactor shutdown.

Table Q8-3

TURBINE OVERSPEED EMERGENCY TRIPS

PLANT	NPE	CAUSE
San Onofre 1	PWRIX.D.3	Turbine tripped by backup overspeed trip device, partial loss of load, generator out-of-step caused by low excitation. (2 events)
Point Beach 1	PWRIX.D.6	Turbine trip, overspeed. An improperly wired relay caused an electrical lockout.
Nine Mile Point 1	BWRVI.A.4	Overspeed trip, damaged blades.
Browns Ferry 3	BWRIX.D.52	Overspeed trip. Power-load balance circuit failed relay caused the CVs to fail and fast close. Turbine speed reached 113%.