Mail Envelope Properties (3B9779FB.533 : 15 : 21310)

Subject:	The proposed Technical Specification Bases Section 3/4.5.1
Creation Date:	9/6/01 9:28AM
From:	Mohan Thadani
Created By:	MCT@nrc.gov

Recipients	**Action**	**Date & Time**
stpegs.com Jrmorris (Internet:Jrmorris@stpegs.com)	Transferred	09/06/01 09:28AM

Post Office	**Delivered**	**Route**
stpegs.com		Internet

Files	**Size**	**Date & Time**
MESSAGE	2338	09/06/01 09:28AM

Options

Auto Delete:	No
Expiration Date:	None
Notify Recipients:	Yes
Priority:	Standard
Reply Requested:	No
Return Notification:	None
Concealed Subject:	No
Security:	Standard
To Be Delivered:	Immediate
Status Tracking:	Delivered & Opened

From: Mohan Thadani
To: Internet:Jrmorris@stpegs.com
Date: 9/6/01 9:28AM
Subject: The proposed Technical Specification Bases Section 3/4.5.1

DRAFT REQUEST FIR ADDITIONAL INFORMATION

Please review the following draft request for additional information and indicate a date by which STPNOC can respond to the staff's questions. You can formally respond to this draft request or advise me if you prefer to get formal NRC RAI request.

1. The proposed Technical Specification Bases Section 3/4.5.1, "Accumulators," states "If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 24 hours. In this Condition, the required contents of two accumulators cannot be assumed to reach the core during a LOCA."

It is our understanding that if one accumulator is inoperable, and you have a LOCA with a single failure, then the contents of three accumulators cannot be assumed to reach the core. Please explain why only two accumulators cannot be assumed to reach the core.

2. Also in Technical Specification Bases Section 3/4.5.1, "Accumulators," you state, "Should closure of a valve occur in spite of the interlock, the SI signal provided to the valves would open a closed valve in the event of a LOCA."

Given that you proposed removing all surveillance requirements that test whether the SI signal opens the isolation valves, please describe what assurance you have that the SI signal would open an accumulator isolation valve.

Mail Envelope Properties (3BA112D5.533 : 15 : 21310)

Subject:	Re: South Texas Project Accumulator AOT- Draft Request For Additional Information
Creation Date:	9/13/01 4:11PM
From:	Mohan Thadani
Created By:	MCT@nrc.gov

Recipients	**Action**	**Date & Time**
nrc.gov		
owf2_po.OWFN_DO	Delivered	09/13/01 04:11PM
FMA CC (Frank Akstulewicz)	Opened	09/14/01 06:53AM
SEP CC (Sean Peters)	Opened	09/17/01 06:54AM
stpegs.com	Transferred	09/13/01 04:11PM
awharrison (INTERNET:awharrison@stpegs.co		

Post Office	**Delivered**	**Route**
owf2_po.OWFN_DO	09/13/01 04:11PM	nrc.gov stpegs.com

Files	**Size**	**Date & Time**
MESSAGE	2670	09/13/01 04:11PM

Options

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Expiration Date:	None
Notify Recipients:	Yes
Priority:	Standard
Reply Requested:	No
Return Notification:	None
Concealed Subject:	No
Security:	Standard
To Be Delivered:	Immediate
Status Tracking:	Delivered & Opened

From: Mohan Thadani
To: INTERNET:awharrison@stpegs.com
Date: 9/13/01 4:11PM
Subject: Re: South Texas Project Accumulator AOT- Draft Request For Additional Information

Wayne:

The staff is reviewing the subject amendment request and has identified a need for additional information. The staff is seeking response to the follwing draft questions. We can discuss these questions during a conference call next week. If you determine that you will require formal request for information, we can discuss the schedule for NRC issuance of RAI and STPNOC response during the next week's conference call.

Mohan

DRAFT REQUEST FOR ADDITIONAL INFORMATION

1. The proposed Technical Specification Bases Section 3/4.5.1, "Accumulators," states "If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 24 hours. In this Condition, the required contents of two accumulators cannot be assumed to reach the core during a LOCA."

It is our understanding that if one accumulator is inoperable, and you have a LOCA with a single failure, then the contents of three accumulators cannot be assumed to reach the core. Please explain why only two accumulators cannot be assumed to reach the core.

2. Also in Technical Specification Bases Section 3/4.5.1, "Accumulators," you state, "Should closure of a valve occur in spite of the interlock, the SI signal provided to the valves would open a closed valve in the event of a LOCA."

Given that you proposed removing all surveillance requirements that test whether the SI signal opens the isolation valves, please describe what assurance you have that the SI signal would open an accumulator isolation valve.

CC: Frank Akstulewicz; Sean Peters

From: "Philip Walker" <plwalker@stpegs.com>
To: <MCT@nrc.gov>
Date: 10/16/01 10:29AM
Subject: Proposed Technical Specification Change for ContainmentStructural Integrity

South Texas Project correspondence NOC-AE-01001137, dated August 2, 2001, contains a statement in section 4.0 (page 2 of 5) that the proposed change"does not have a significant impact on safe operation of the South Texas Project." Use of the word "significant" is reflective of the terminology used in the regulations. The proposed change only incorporates the tendon surveillance requirements by reference into the Containment Post-Tensioning System Surveillance Program and there is no actual change in the requirements. Consequently, there is no impact on safe operation of the South Texas Project as a result of this proposed change.

If there are any further questions, please contact me at 361-972-8392.

Philip Walker
Staff Licensing Engineer
South Texas Project

CC: "Scott Head" <smhead.GWPO_NASSUR.GWDOM_STP@stpegs.com>

Mail Envelope Properties (3BCC441B.B1F : 2 : 60191)

Subject:	Proposed Technical Specification Change for ContainmentStructural Integrity
Creation Date:	10/16/01 10:24AM
From:	"Philip Walker" <plwalker@stpegs.com>
Created By:	plwalker@stpegs.com

Recipients
nrc.gov
owf4_po.OWFN_DO
MCT (Mohan Thadani)

stpegs.com
smhead.GWPO_NASSUR.GWDOM_STP CC (Scott Hea

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owf4_po.OWFN_DO	nrc.gov
	stpegs.com

Files	**Size**	**Date & Time**
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Mime.822	1604	

Options

Expiration Date:	None
Priority:	Standard
Reply Requested:	No
Return Notification:	None
Concealed Subject:	No
Security:	Standard

Mail Envelope Properties (3BA64035.533 : 15 : 21310)

Subject:	DRAFT QUESTIONS-STEAM GENERATORS 90 DAY REPORT
Creation Date:	9/17/01 2:25PM
From:	Mohan Thadani
Created By:	MCT@nrc.gov

Recipients	**Action**	**Date & Time**
stpegs.com	Transferred	09/17/01 02:26PM
jtconly (Internet:jtconly@stpegs.com)		
nrc.gov		
owf2_po.OWFN_DO	Delivered	09/17/01 02:26PM
KJK1 CC (Kenneth Karwoski)	Opened	09/17/01 02:27PM

Post Office	**Delivered**	**Route**
stpegs.com		Internet
owf2_po.OWFN_DO	09/17/01 02:26PM	nrc.gov

Files	**Size**	**Date & Time**
MESSAGE	23769	09/17/01 02:26PM

Options	
Auto Delete:	No
Expiration Date:	None
Notify Recipients:	Yes
Priority:	Standard
Reply Requested:	No
Return Notification:	None
Concealed Subject:	No
Security:	Standard
To Be Delivered:	Immediate
Status Tracking:	Delivered & Opened

From: Mohan Thadani
To: Internet:jtconly@stpegs.com
Date: 9/17/01 2:25PM
Subject: DRAFT QUESTIONS-STEAM GENERATORS 90 DAY REPORT

John:

The NRC staff has identified draft questions on the STP Unit 2 steam generator 90 day report. Ken Karwoski discussed these questions with you by phone. Please advise if you will need formal transmittal of these questions or will respond formally to the following **draft.**

Thanks.

Mohan

DRAFT QUESTIONS ON SOUTH TEXAS PROJECT UNIT 2 STEAM GENERATOR 90 DAY REPORT.

By letter dated June 28, 2001, the licensee for South Texas Project Unit 2 (STP 2) submitted its steam generator 90-day report which summarizes the implementation of the steam generator tube voltage-based repair criteria during refueling outage 2RE08. In order to complete the review of this report, the NRC staff requests information related to the following topics be provided.

1. Accuracy of EOC voltage predictions

Implementation of the voltage-based repair criteria requires determination of the probability of burst and the postulated primary-to-secondary leakage following a steam line break event. To perform this analysis, the expected number of locations with degradation and the severity of the degradation at these locations at the end of the next operating cycle is needed. In projecting the end-of-cycle (EOC) conditions, the indications known to be left in service at the beginning-of-cycle (BOC) are adjusted to account for missed indications (due to equipment and personnel limitations) and the development of new indications. These adjustments are made through the use of a probability of detection (POD) factor of 0.6. This adjustment determines the number of indications expected at the end of the next operating interval. To determine the anticipated severity of these indications (i.e., voltage for GL 95-05 indications) at the end of the next operating interval, these indications are adjusted for potential growth during the next operating cycle and for an uncertainty in the measurement due to wearing of the probe and due to analyst variability. The resultant distribution of indications is then used in determining the probability that a tube will burst and the leakage under postulated accident conditions. If the distribution of indications (number and/or severity) at the EOC is under-predicted, it is likely that the resultant probability of burst and/or postulated leakage may be under-predicted.

Historically, the methodology for predicting the EOC voltage distribution has been conservative in predicting the number of indications (i.e., through the use of a 0.6 POD) and has reasonably predicted the severity of indications (through the use of historic growth rates and models for measurement uncertainty). In the case of STP 2 where the postulated leakage during a steam line break event is approaching the limit, it is important to evaluate the "conservatism" in the prediction of EOC voltage distributions, particularly the larger voltage indications which tend to contribute the most to burst probability and leakage estimates.

Based on the staff's review of the material provided in References 1 through 3, several instances where the EOC voltage distribution was under predicted both in terms of the number and severity of indications were identified. The following tables illustrate the results.

Table 1: Comparison of Number of Indications Predicted versus Observed for Cycles 6, 7, and 8

Steam Generator	Cycle 6 (1997-1998)	Cycle 7 (1998-1999)	Cycle 8 (1999-2001)

	Projected		Actual	Projected		Actual	Projected	Actual
A	322	188	293	330	509	611		
B	565	500	836	815	1294	1229		
C	437	456	749	602	927	972		
D	437	340	558	515	792	767		
Total	1761	1484	2436	2262	3522	3579		

Source: Table 7-4 of Ref. 3, Table 6-4 of Ref. 2, and Table 6-3 of Ref. 1 of 90-day reports.

As can be seen from Table 1, the number of indications exceeded projections in one steam generator in Cycle 6, one steam generator in Cycle 7, and in two steam generators in cycle 8. The projections for the number of indications in the other steam generators were comparable to what was observed for the last 2 cycles.

With respect to the severity of the indications detected, the methodology tended to under predict the number of larger voltage indications. Table 2 provides the number of indications detected that were greater than 1 volt for Cycles 6 through 8 and compares it to the projected results. Table 3 provides similar information for indications greater than 2 volts. As can be seen from Table 3, the larger voltage indications tended to be under predicted.

Table 2: Comparison of Severity of Indications Predicted versus Observed for Cycles 6, 7, and 8 (greater than 1 volt indications)

Steam Generator Cycle 6 (1997-1998) Cycle 7 (1998-1999) Cycle 8 (1999-2001)
Projected > 1 V Actual
> 1 V Projected > 1 V Actual
> 1 V Projected > 1 V Actual
> 1 V

A	94	18	35	33	127	106
B	28	3	26	37	244	108
C	55	10	37	48	227	117
D	12	8	44	42	158	117
Total	189	39	142	160	758	448

Source: Table 7-4 of of Ref. 3, Table 6-4 of Ref. 2, and Table 6-3 of Ref. 1

Table 3: Comparison of Severity of Indications Predicted versus Observed for Cycles 6, 7, and 8 (greater than 2 or 3 volt indications)

Steam Generator Cycle 6 (1997-1998) Cycle 7 (1998-1999) Cycle 8 (1999-2001)
Projected > 2 V Actual
> 2 V Projected > 2 V Actual
> 2 V Projected > 2 V Actual
> 2 V

A	2	4	6	7	18	43
B	1	0	1	8	34	33
C	0	1	2	11	32	41
D	0	1	3	8	24	46
Total	3	6	12	34	108	163

Source: Table 7-4 of Ref. 3, Table 6-4 of Ref. 2, and Table 6-3 of Ref. 1

The under prediction of the severity of the degradation could be attributed to higher than expected growth rates and/or a lower probability of detection at STP 2 with a bobbin coil. With respect to the growth rates,

Table 4 illustrates the average growth rate has been increasing since cycle 6. With respect to the probability of detection, the staff notes that the RPC confirmation rate of bobbin indications appears to be very high (nearly 100%) at STP 2. Based on staff recollection, the confirmation rate at other plants is lower.

Table 4: Average Growth Rates for Cycles 5, 6, 7, and 8

Cycle	Period	Duration (EFPD)	Average BOC Voltage	Number of Indications	Average Growth Rate per EFPY
5	1995-1997	450	703	31	0.31
6 (2RE06)	1997-1998	564.9	1484	27	0.31
7 (2RE07)	1998-1999	342.5	2262	45	0.41
8 (2RE08)	1999-2001	458	3580	82	0.37
9	2001-2002	485 (planned)			

Source: Table 3-5 and page 6-2 of Ref. 1, and Ref. 4 (page 12 of 17).

Table 5 presents the indications left in service at BOC 8 and 9 as a function of voltage indicating that a similar distribution of indications was left in service for these 2 cycles.

Table 5: Indications Left in Service as a Function of Voltage

Voltage		BOC 8 (1999)		BOC 9 (2001)
0.1	0b27	972		
D	437	3	1	
0.2	35	45		
0.3	215	292		
0.4	450	552		
0.5	435	539		
0.6	353	475		
0.7	224	246		
0.8	146	150		
0.9	95	80		
1.0	61	39		
1.1	0	19		
1.2	1	11		
1.3	0	2		
1.4	0	4		
1.5	0	1		
	TOTALS		2015	2456

Source: Table 3-1 of Ref. 2 and Table 3-1 of Ref. 1

To summarize the above, (1) the number of indications was under predicted for 1 of the 4 steam generators at EOC 7 and for 2 of the 4 steam generators at EOC 8, (2) the number of indications above 2 volts was under predicted in all 4 steam generators at EOC 7, and the number of indications above 3 volts was under predicted in all 4 SG at EOC 8, (3) the composite growth rate increased from Cycle 6 (27%) to Cycle 7 (45.4%) to Cycle 8 (81.9%), and (4) more BOC indications were left in service this cycle than last (although the number of indications above 0.9 volts is comparable to prior cycle)

The above results appear to question the use of a 0.6 POD and/or the use of historic growth rates to predict EOC conditions at STP 2. As a result, please provide the basis for assuming the methodology used to predict the expected EOC 9 voltage distribution (and the resultant primary-to-secondary leakage and probability of burst estimates) will be conservative for Cycle 9.

2. Secondary Side Pressure Test Implications

As discussed in Reference 4, operational primary-to-secondary leakage was identified during Cycle 8, and a 600 psi secondary side pressure test was conducted during the subsequent refueling outage to identify possible leaking tubes. The leakage rate under the test conditions was no greater than 1 drop per minute and many tubes did not drip at all rather they were just wet. In Reference 1, 54 tubes with indications above 4 volts were identified as leakers during this pressure test. In addition, in Reference 5, it was indicated that approximately 40 tubes were preventively plugged due to being suspected leaking tubes (presumably these were below the repair limits). For the tubes suspected of being leakers as a result of the secondary side pressure test, please provide the nature of all eddy current indications in these tubes. Based on this information, please discuss whether the results from the secondary side pressure tests draw into question the use of the generic probability of leakage model at STP 2.

3. Correlation between in-situ leakage test results and actual operating leakage

During 2RE08, six indications at the tube support plate elevations were in-situ leak and pressure tested as discussed in Reference 4. All of these indications leaked during the secondary side pressure test discussed above. With this information, the information provided in Attachment 2 to Reference 1, the information discussed during conference calls and at the April 19, 2001, public meeting, the staff attempted to correlate the total leakage observed from a steam generator during actual plant operation to the leakage actually measured during the in-situ pressure tests discussed above. Based on the information provided the staff could not reconcile the amount of leakage observed during plant operation to the amount of leakage reported during the in-situ pressure tests as discussed below.

The total leakage from steam generator B during normal operation was 7.5 gallons per day (gpd) at the end of cycle 8. One of the more "severe" indications was pressure tested and the "best estimate normal operating leak rate" was determined by the licensee to be 0.03 gpd. Assuming this was just an average indication (which is probably a non-conservative assumption), it would take approximately 250 such indications in steam generator B to account for the 7.5 gallons per day total steam generator leakage (assuming the 7.5 gpd and 0.03 gpd are reported for the same temperature conditions).

As a result of the above, the staff requests the licensee assess how the leakage measured during the in-situ pressure tests corresponds to the leakage measured during actual plant operation. The assessment should address the conditions under which the in-situ measurements were made (i.e., all pressures and temperatures) and the subsequent adjustments to the data to account for differences in temperature and pressure. All data should be provided including data collected under normal operating and steam line break conditions. The assessment should also assess the possibility that the leakage was coming from other types of degradation and/or very low voltage indications. Please consider the information from this assessment in responding to question 1 above.

References:

1. June 28, 2001 letter from Mark E. Kanavos, South Texas Project Nuclear Operating Company, "2REO8 Steam Generator Tube Voltage-Based Repair Criteria 90-day Report"

2. January, 25, 2000 letter from S.E. Thomas, South Texas Project Nuclear Operating Company, "Unit 2 Seventh Refueling Outage Steam Generator Tube Voltage Based Repair Criteria 90 day Report"

3. January 19, 1999 letter from S.E. Thomas, South Texas Project Nuclear Operating Company, "2REO6 Steam Generator Tube Voltage-Based Repair Criteria 90-day Report"

4. May 10, 2001 letter from Mark Kanavos, South Texas Project Nuclear Operating Company, "Licensee Event Report 2-01-003, Steam Generator 2C Classified as Category C-3"

5. June 27, 2001 letter from M.E. Kanavos, South Texas Project Nuclear Operating Company, "Special Report - 2RE08 Refueling Outage Inservice Inspection Results for Steam Generator Tubing"

CC: Kenneth Karwoski

From: Kenneth Karwoski
To: Internet:jtconly@stpegs.com
Date: 9/19/01 12:54PM
Subject: REVISED QUESTION 2

John,

Per our phone discussion, I revised question 2 as follows:

2. As discussed in Reference 4, operational primary-to-secondary leakage was identified during Cycle 8, and a 600 psi secondary side pressure test was conducted during the subsequent refueling outage to identify possible leaking tubes. The leakage rate under the test conditions was no greater than 1 drop per minute and many tubes did not drip at all rather they were just wet. In Reference 1, 54 tubes with indications above 4 volts were identified as leakers during this pressure test. In addition, in Reference 5, it was indicated that approximately 40 tubes were preventively plugged due to being suspected leaking tubes (presumably these were below the repair limits). During the April 19th meeting, a table listing all of the tubes identified as leakers during the secondary side pressure test was provided along with the voltages for tube support plate indications. Several of these tubes leaked even though the indications in the tube were of relatively small voltages (and the differential pressure during the pressure test was less than would be experienced during a steam line break). Are the results of the secondary side pressure test consistent with the generic probability of leakage model? For the tubes that leaked during the pressure test, please provide a list of any other eddy current indications detected in these tubes (e.g., wear, free span indication, etc.) and address the possibility that these indications were contributing to the leakage.

Please let me know if you have any questions.

Thanks,

Ken
301-415-2752

CC: Edmund Sullivan; Mohan Thadani

Mail Envelope Properties (3BA8CDD1.4E4 : 15 : 20032)

Subject:	REVISED QUESTION 2
Creation Date:	9/19/01 12:54PM
From:	Kenneth Karwoski
Created By:	KJK1@nrc.gov

Recipients
stpegs.com
jtconly (Internet:jtconly@stpegs.com)

nrc.gov
owf2_po.OWFN_DO
EJS CC (Edmund Sullivan)

nrc.gov
owf4_po.OWFN_DO
MCT CC (Mohan Thadani)

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Files	**Size**	**Date & Time**
MESSAGE	2462	09/19/01 12:54PM

Options

Expiration Date:	None
Priority:	Standard
Reply Requested:	No
Return Notification:	None
Concealed Subject:	No
Security:	Standard

Maine Yankee
50 - 309

MAINE YANYEE/NRC DISCUSSION (TELECON SEPTEMBER 15, 2001) ON EARLY RELEASE OF BACKLAND

Purpose: Discuss issues related to the MY Partial Site Release (PSR) submittial dated August 16,2001, RA-010131. Telecon closes DCB-263 & N200200126

Information

Licensee: Maine Yankee
Subject: Summary of Telecon with Participants
Date: Sept. 17, 2001, 1:00 PM to 2:00 PM
Participants:
NRC HQ: M. Belvins, J-C. Dehmel, L. Pittiglio, and M. Webb
NRC Region I: none
MY Staff: J. Darman, R. Decker, G. Cesare , and M. Withney
State of Maine: P. Dostie and D. Randall
Friends of the Coast: none

Comments/Discussion:
In summary, the NRC comments and discussions involved:

1. MY needs to carry forward into the next version of the LTP all commitments made in the current PSR package.

2. MY needs to make Attach. 2A (Sect. 2) of the LTP consistent with the PSR since Attach. 2A presents information (data from REMP and special surveys) that is not presented in the current PSR package.

3. The PSR needs to precisely refer to the areas of the MY site and total acreage covered by the PSR, rather than using approximate estimates. The information presented in App. H needs to be cited into the main section.

4. The PSR needs to elaborate on the basis of selecting Cs-137 as the surrogate radionuclide and how the results of surveys are being interpreted for the disposition of nine other radionuclides (non-gamma emitters).

5. The discussion on the past use of the sanitary system used by MY staff on Eaton Farm needs to be revised since the current discussion implies that discharge of materials were made in that septic system.

6. Any comparison to survey results with or conclusions reached by State the Maine's staff and data inferred from other sources must be fully referenced/documented in the PSR package.

7. Appendix D presenting the results of the Kruskal-Wallis test needs to be revised to make it consistent with the method of NUREG-1575 and -1505. The test can only be conducted on treating the three reference areas as separate areas rather than combining them as one area.

8. The PSR package needs to describe the system used to conduct *in situ* gamma spectroscopy for Cs-137 and NORM in a manner that is consistent with the descriptions of the other systems used to conduct site surveys.

9. The PSR needs to note that drive over surface scan surveys (using the TSA Systems, Ltd, VRM-1X) were conducted only for qualitative purposes and all discussions related to quantitative calibration and its basis must be revised since the calibration data (cps to pCi/g) were not used in presenting the results obtained with that system.

10. The PSR needs to qualify whether any of the exposure rate measurements were corrected for the difference in gamma radiation responses between the sodium iodide survey meter and that of the pressurized ion chamber (PIC) system. The discussion needs to indicate the implication in interpreting the results if the results were not corrected by this ratio. Similarly, the PSR needs to cite the basis of the calibration factor and radionuclide used for calibrating the sodium iodide system.

11. The delineation of the site property boundary along Westport Bridge Road shown in Fig. 2 is different than that described in App. H, based on surveyor's data. The two site maps contained in the PSR must be made consistent with one another.

12. NRC noted that it still needs to review the information presented in the Site Characterization Report and Historical Site Assessment Report since they are both referenced in the PSR as supporting documents. MY indicated that they expect to submit the reports to the NRC within the next two weeks.

AGREEMENTS/RESPONSE

1. Regarding the above comments, MY indicated that they will issue to the NRC revised sections and/or pages of the PSR within the next 30 to 60 days, depending on workload. MY has significant obligations based on the Settlement Agreement and has given that the highest priority.

2. MY noted that they indicated they may wait until they receive the NRC's RAI on the LTP Revision 2 before issuing a third revision of the LTP. This approach was found acceptable to the NRC as it would eliminate an extra iteration.

All discussions were adjourned shortly before 2:00 PM.

Maine Yankee
50-309

Memo to File

Licensee: Maine Yankee
Subject: Summary of Telecon
Date: Sept. 19, 2001, 1:00 PM to 2:00 PM
Participants:
NRC HQ: J-C. Dehmel, R. Nelson, and L. Pittiglio
NRC Region I: none
MY Staff: G. Cesare, J. Darman, R. Decker, G. Pillsbury, T. Williamson, and M. Withney
State of Maine: P. Dostie
Friends of the Coast: R. Shadis

MY provided an overview of its ongoing activities. The topics addressed work completed to date in support of the Settlement Agreement (signed on Aug. 31) with the State of Maine and Friends of the Coast, and action items still due to the NRC. The items still due to the NRC include the Site Characterization Report, Historical Site Assessment Report, calculation package, dose modeling sensitivity study (backfill vs dose), and groundwater reports. MY noted that the Site Characterization Report and Historical Site Assessment Report are expected to be mailed on/or about Sept. 28 and the balance should go out by Oct. 4. In light of the settlement agreement and possible future ramifications on the LTP, MY pointed out that there may even be a fourth revision to the LTP, depending on how the issues noted in the settlement are addressed in both scheduling and technical terms. MY affirmed that its objective is to get the LTP approved and SER issued as soon as is feasible, given that it has undertaken some site activities at risk. MY briefly outlined its understanding of the remaining issues still to be resolved in the Partial Site Release Application package and noted that it expects to address them within the next 30 to 60 days.

MY highlighted the content of the Settlement Agreement and presented a brief discussion on some of the technical issues raised by the State of Maine and Friends of the Coast. The agreement ends the hearing process before the ASLB. The major issues include defining the status of the intertidal zone, radionuclide distributions and ratios in concrete, method to address the variability in characterization results in the LTP process, assessment of alpha emitting radionuclides, free release criteria, license conditions, ground water sampling, compliance with the enhanced state cleanup standards, marine sampling, dose modeling, radiological assessment of the forebay and diffuser discharge piping, storm drain flow rate measurements, vegetation and soil sampling, background determination, enhance historical site assessment, resolution and decision making process in resolving the noted technical issues.

The NRC briefly discussed its current activities and noted that questions are being identified during the review of the current LTP (Rev. 2). Because of manpower commitments, a possible delay of a few weeks is expected to impact the issuance of the RAI; however, the NRC may decide to issue its RAIs in two phases to expedite the process. MY will be updated on the NRC's schedule as time progresses.

All technical discussions were adjourned and the next telecon was set for Oct. 3, 1:00 PM.

Second Request for Additional Information on
Materials and Chemical Engineering Issues
Extended Power Uprate License Amendment Application
Arkansas Nuclear One, Unit 2

In Section 2.4.3.1, "Primary-side Chemistry," on page 2-16 of the application, the licensee states that:

"The SAR [Safety Analysis Report] section is unaffected except for the following:

CE Nuclear Power Co., LLC (CENP, formerly ABB-CE) has evaluated a concern with RSG [replacement steam generator] and core designs regarding deposition of nickel on the core. Based on CENP recommendations, a new lithium strategy is being incorporated starting in Cycle 15."

The staff requests the licensee to provide details on this new lithium strategy (i.e., a description of the strategy, its purpose, its frequency and basis for its use). In addition, the staff requests information regarding the effects of this strategy on the power uprate conditions of flow, pressure, and temperature, and the results of the licensee's evaluation for power uprate.

Version	Power (MWt)	MSSV (%)	HPSI Curve @ 990 psia	Limiting PCT (F)	Delta (F)
S1M – 30% Plugging	2900	1	Base	2011	
S2M – 30% Plugging	2900	3	-3.2 %	1798	-213
S2M – RSG	2900	3	-5.9 %	1905	+107
S2M – Power Uprate	3087	3	-5.9 %	2066	+161

Post-it™ brand fax transmittal memo 7671	# of pages ▸ 1
To Tom Alexion	From Dennis Boyd
Co. NRC	Co. Entergy
Dept.	Phone #
Fax #	Fax #

Response to Request for Additional Information on Probabilistic Risk Assessment Regarding the ANO-2 Power Uprate License Application

NRC Question 1

Totaling up the individual impacts for the fire analysis, ANO-2 shows a change in core damage frequency (CDF) of 1.6E-5, with a base CDF value of just over 1E-4. This is in Region I on the chart in Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," where "applications ... would not normally be considered." Please provide additional discussion and any additional analyses to justify why these high resulting values are acceptable and/or describe any mitigative or compensatory features that would reduce the major risk contributors (i.e., Cable Spreading Room, Diesel Corridor, Lower South Electrical/Piping Penetration Room, North and South Switchgear Rooms, MCC2B63 Room, etc.). Many of these impacts seem to be due to operator recovery actions available times, which were determined using the CENTS code by calculating the time to core uncovery as opposed to the time to core melt. Thus, the resulting human error probabilities (HEPs) have high, conservative values. What other conservatisms in the modeling may account for the resulting high fire CDFs? How would the results be affected by using the time to core melt and removing these other conservatisms from the CENTS code?

ANO Response

The fire portion of the ANO-2 Individual Plant Examination for External Events (IPEEE) response was performed using the Electric Power Research Institute (EPRI) Fire Induced Vulnerability Evaluation (FIVE) Methodology as documented in EPRI TR-100370s. This methodology was approved for this use in a letter from the NRC to the Nuclear Utility Management and Research Council (NUMARC) dated August 21, 1991, "NRC's Staff Evaluation Report on Revised NUMARC/EPRI Fire Vulnerability Evaluation (FIVE) Methodology."

As stated in the Introduction to EPRI Report TR-100370s, "FIVE is oriented toward uncovering limiting plant design or operating characteristics (vulnerabilities) that make certain fire-initiated event more likely than others." The FIVE methodology is not a fire risk analysis, but a fire vulnerability analysis; as such, it produces a conservatively high screening estimate, not a best-estimate value, for the Core Damage Frequency (CDF) for each fire zone. The CDF of each of the significant fire compartments (i.e., those with a CDF > 1E-6/rx-yr) was compared to the closure guidelines provided in Section 4.3 of NEI 91-04, Revision 1, "Severe Accident Issue Closure Guidelines," dated December 1994. Closure was obtained individually on each significant fire compartment. Consistent with the fact that the FIVE process is a vulnerability analysis and not a risk analysis, a single fire CDF (i.e., the sum of fire zone CDFs) was not reported, nor should be used, as an estimate for the ANO-2 fire-induced CDF.

This perspective on the conservative nature of the FIVE methodology and on the conservative nature of its CDF results is apparently shared by the Staff in its draft version of NUREG-1742, Vol.1, "Perspectives Gained from the Individual Plant Examination of External Events (IPEEE) Program," dated April 2001 (Draft Report for Public Comment). In Section 3.4.1 of this report, it was noted that "FIVE ... is largely equivalent to a fire area/zone screening analysis. It is not intended to produce a detailed quantification of fire CDF, but rather, to identify those plant areas/zones that might represent important fire CDF contributors." Section 1.3 of the report notes that "IPEEEs are intended to yield predominantly qualitative perspectives, rather than more quantitative findings." Section 3.3 further elaborates that although "CDF is the primary measure of fire-induced plant risk that emerges from the IPEEE fire analyses ... the direct comparison of absolute CDF results was not generally considered to be appropriate ...". Section 3.4.1 states that the "perception that FIVE is generally a conservative approach in comparison to fire PRA methods appears to be confirmed when the total CDF for various methodologies are compared. Those submittals based solely on FIVE, in general, reported larger fire-induced CDF results than the submittals that used other methods."

The conservative nature of the FIVE methodology described in NUREG-1742 applies to the ANO-2 fire analysis. The ANO-2 IPEEE fire analysis was performed via a series of screening analyses of the various zones. The first of those screenings assumed failure of all components in the zone and components with cables (i.e., power, control, or instrumentation cables) in the zone. Any zone not screened using this approach was identified for further analysis. This additional analysis involved identifying the dominant failures in each unscreened zone. For each unscreened zone, these dominant failures were individually assessed to determine whether a fire would indeed have failed the component of interest. If a determination was made that a component would not be affected by a fire in the zone, the zone was requantified with the component set to its nominal failure value. Iterations were performed on the unscreened zones until they screened or until the CDF for the zone was reduced to some frequency that was deemed to be acceptable. Potential fire vulnerabilities were identified based on the unscreened zones. Since the iterations on the unscreened zones were concluded when it was felt that the intent of GL-88-20 was met, CDF results are not indicative of a true fire risk.

Besides the conservative nature of the ANO-2 FIVE methodology, other conservatisms are present in the ANO-2 fire IPEEE analysis and the fire analysis submitted as part of the ANO-2 power uprate submittal. Important among these conservatisms is the use of operator recovery action available times that are based on the CENTS-generated time to core uncovery as opposed to the time to core melt. Another important conservative assumption of the fire analyses is that for each fire zone it was assumed that all failure modes occur for all equipment in the zone. The Appendix R cable routing database and additional investigations were used to identify the unaffected equipment. It should also be noted that the fire analyses conservatively took no credit for the Alternate AC (AAC) Diesel Generator (also known as the Station Blackout Diesel Generator).

Thus, the conservative nature of the ANO-2 FIVE-based fire analysis and conservatisms used in this analysis make it inappropriate to make a direct comparison of the sum of the fire zone CDFs with the Regulatory Guide 1.174 risk acceptance guidelines. If the total fire CDF is used as a figure of merit, it is probably more appropriate to compare the change in the fire CDF to the change in the internal events CDF expected as a result of the 7.5% increase in power: the 14% increase in the sum of the fire zone CDFs is very consistent with the estimated 15.8% increase in the internal events CDF. The fire risk results should be considered acceptable, given that they are consistent to the internal events CDF results, which is acceptable using the Regulatory Guide 1.174 risk acceptance guidelines. Based on this perspective, additional analysis of the ANO-2 fire-induced risk associated with the extended power uprate was not performed.

NRC Question 2

The licensee indicated that the potential for creating an initiating event due to a spurious main steam isolation signal (MSIS) or containment spray actuation signal (CSAS) is compensated by trip hardening their signals. Though this modification is argued to compensate for the potential increases in spurious signals, it is stated that it is not quantified. How are these signals addressed in the ANO-2 probabilistic risk assessment (PRA) models? Does the ANO-2 EPU PRA explicitly model these signals as designed (and to be installed), considering their benefits (i.e., reduced frequency due to trip hardening) and potential adverse impacts (e.g., spurious operation) on initiating event frequency and following an initiating event? If not, will these signals be incorporated as part of a future update of the model and is this planned update prior to entering EPU operations?

ANO Response

A containment spray actuation signal (CSAS) has been added to main feedwater and main steam components to ensure isolation of these systems following a main steam line break (MSLB) on high containment pressure. This modification was added as part of the replacement steam generator effort and is already installed in the plant. The larger steam generator inventory to accommodate power uprate necessitated this new signal; hence, this plant change was added to the power uprate model.

The CSAS signals and relays are modeled in the power uprate as basic events in the fault trees to each component as a potential failure to actuate when the signal is needed for the event mitigation. The spurious actuation causing a loss of feedwater inappropriately was not modeled in the power uprate effort due to the minimal impact it has on the model and the difficult model update required. This additional detail will be implemented in the next revision to the ANO-2 model.

The spurious actuation of an MSIS or CSAS relay is also considered in the initiating event frequency, %T16. The pre-uprated model only considered the MSIS signal. The power uprate model considered the additional CSAS signal in the basic events but did not update the initiating event frequency. Hence, the additional system failures due to the new CSAS signal have been considered in the model, however, no credit has been taken for a reduction in the initiating event frequency. The reduction in the initiating event frequency is due to the logic change.

A new signal was added to critical main feedwater and main steam components. Actuation of these components can cause a plant trip and loss of feedwater; however, the logic was improved by installing two relays in series. With the old plant configuration, an individual relay failure could cause a plant trip and loss of feedwater. The revised plant configuration adds the CSAS signal to feedwater and main steam components but changes the relay configuration to require two relay failures to initiate a spurious actuation of CSAS or MSIS.

NRC Question 3

The information states in a couple [of] places that the uprate could cause components to wear out more quickly or involve more often preventive maintenance. How did the licensee address these conditions within the EPU PRA model? Were failure rates and/or maintenance outage rates increased for selected equipment that would be affected by the EPU? If so, please identify the equipment affected and provide the old and new failure rate/maintenance outage values (or if multiple components were increased by a proportional amount, provide the percentage increase). If not, please briefly explain why not and the basis for the acceptability of the potential increases in equipment being unavailable due to maintenance without modeling them in the EPU PRA (e.g., maintenance times used in model bound EPU projected maintenance times).

ANO Response

The effects of increased component wear out and increased frequency of preventive maintenance were not explicitly incorporated into the ANO-2 Power Uprate PRA model. Per our response in our letter [Ref. 3a], we recognized the increased potential for equipment wear out and indicated that the existing component monitoring programs will trend and minimize any additional wear that may result from the power uprate. Component failure rates are not expected to change with the power uprate. It is noted that train-level changes to equipment unavailability for systems modeled in the ANO-2 PSA are tracked as part of our PSA model maintenance. We periodically review equipment unavailabilities and update the model with their values. It should be noted that the periodic updating of plant failure and unavailability data used in the PSA model is only one aspect of maintaining the PSA model consistent with the as-built plant. By procedure, all plant changes, including hardware and procedural changes, are periodically reviewed, prioritized in terms of their impact on the model, and incorporated into the model in a manner consistent with their priority. In addition, although currently an informal process, we review our CDF history on a quarterly basis. This process provides further assurance that we identify risk-significant trends.

NRC Question 4

For shutdown operations, what is the shortest "time to boiling" calculated during a typical outage and when in the outage does this occur (e.g., mid-loop operations)? Describe other typical shutdown operations in which the containment cannot be closed within the estimated "time to boiling." For these shutdown operations and any other times of extremely short "time to boiling" duration, does ANO-2 take any additional precautionary/mitigative actions other than those cited in their response of June 28, 2001?

ANO Response

The shortest time to boiling following entry into cold shutdown conditions during a "typical" outage is approximately 20 minutes. This shortest time is most likely to occur during the first reduced inventory window (i.e., during mid-loop operation). However, typical shutdown operations never result in a containment closure time that exceeds the estimated time to boiling, even during mid-loop operation. Of all containment breaches that usually occur during an outage, closure of the equipment hatch is most limiting in terms of the amount of time required. In numerous tests, ANO-2 has demonstrated its ability to effect equipment hatch closure in 5 to 15 minutes, usually in less than 10 minutes. Even so, during mid-loop operation, the containment equipment hatch is typically closed. For other breaches during this time, the ANO-2 Outage Risk Management Guidelines (ORMGs) require that closure materials be staged in advance and when possible, closure capability be established from the outside. A person capable of quickly closing the flow path through the penetration must also be present. These actions assure that any breach of containment will be closed well in advance of any boiling should a loss of shutdown cooling occur.

The ORMGs also state:

> "During Reduced Inventory conditions, the only containment breaches allowed without specific approval of the Operations Manager are LLRT openings and via the containment ventilation/purge system. All containment breaches will have the capability to be closed within 45 minutes and, where possible, within the estimated time to boiling."

The 45-minute closure time is based on a requirement of NRC Generic Letter 88-17, Loss of Decay Heat Removal." However, in recognition that the containment could become "uninhabitable" very quickly after the onset of boiling, ANO makes every effort to ensure containment closure can be completed in less than the estimated time to boiling. A Shutdown Operations Protection Plan (SOPP) is developed for each outage based on the ORMGs. This plan identifies the minimum set of "safety functions/systems" required for various expected plant conditions during the outage. One of the "safety functions" addressed in the SOPP is containment closure. The outage schedule is then reviewed against the requirements of the ORMGs and SOPP to ensure all requirements are met, including minimizing containment breaches while fuel is in the reactor and ensuring the capability to close containment prior to the estimated time to boiling for those breaches that are scheduled. Thus, while the ORMGs allow for a containment breach that cannot be closed prior to the estimated time to boiling, such a breach is not planned for in the outage schedule and would most likely only occur if a gross penetration failure is found while at reduced inventory. Even then, the Operations Manager would have to be convinced that acceptance of the temporary condition is prudent, versus exiting the reduced inventory condition, after weighing all plant conditions at the time.

While decay heat will increase due to power uprate, the above guidelines and philosophy for managing ANO-2 outages will not. That is, the time to boiling at any given time following plant shutdown will decrease slightly following power uprate, compared to the current licensed power level, but ANO-2 will continue to plan its outages to ensure that containment breaches can be closed prior to the estimated time to boiling.

NRC Question 5

Is all equipment operated within its rated design capacity (e.g., transformers, switchgear, pumps, etc.)? If not, please identify the equipment operated beyond its rating and state why the equipment operations are acceptable (e.g., operator actions required to manually load shed overloaded transformer within a set time). If there are operator actions involved in the actions to protect the equipment, what are these actions and have they been assessed and incorporated into the EPU PRA?

ANO Response

All equipment will operate within its rated design capacity for power uprate with no increase in operator actions. Since the inception of the replacement steam generators and power uprate projects, significant changes have been made to major ANO-2 structures, systems and components (SSCs) to make this statement true. A significantly long list of equipment changes is listed in Table 2-2 of the power uprate licensing report (PULR).

A review of the table indicates that no safety-related equipment has been modified for power uprate. As part of containment uprate, the safety-related containment service water cooling coils were replaced. These are now installed and available for service during accident conditions. As stated in the various sections of the PULR, all other safety-related equipment has adequate margin to perform its design basis function.

There are other examples that demonstrate that the engineering review for power uprate has made changes to SSCs or plant procedures in order to keep equipment within its rated design capacity:

1. The procedure for operating the auxiliary feedwater (AFW) system is revised to require a valve lineup so the associated piping and piping components cannot be overpressurized when AFW pumps are placed into service.

2. ANO engineering is working with the equipment manufacturer of two high pressure feedwater heaters to re-rate the equipment for power uprate conditions. The feedwater heaters have been in service for approximately twenty years. Therefore, the as-found equipment nozzle wall thickness is measured and documented as part of this re-rating rather than assume the wall thickness shown on original equipment drawings.

3. ANO has an on-going flow accelerated corrosion (FAC) program. Increases in fluid velocities due to power uprate are evaluated as part of this program. As cited in the PULR Table 2-2, the heater drain pump recirculation lines and control valves are being replaced with larger size components in order to reduce wear by reducing the velocities through these lines.

In summary, ANO has been diligent in making modifications for power uprate to all equipment, including some very major equipment as listed in the PULR Table 2-2. This equipment has adequate margin to operate within its design capacity.

NRC Question 6

The operator action available times affected by the EPU are expected to change inversely proportionally with the increase in decay heat resulting from the EPU. However, many of the available times for operator actions listed by the licensee decrease by a larger percentage (17-23%) than expected, considering the EPU is only a 7.5% increase. What is the reason for these larger than expected decreases in available times? If this is related to the conservatisms identified in Item 1 above, how would the results be affected by using the time to core melt instead of time to core uncovery in the CENTS code?

ANO Response

The reductions in operator action available times were based on direct comparisons of CENTS results for the time to core uncovery before and after uprate. The time to core damage is not expected to significantly change the percentage change in operator response time. The times with the larger percentage changes are related to cases in which once through cooling is initiated as a back-up cooling method. For these cases, it is critical to open the emergency core cooling system (ECCS) vent valve early enough to allow for enough inventory in the core to keep the core cool until the RCS depressurizes to the point of high pressure safety injection. Due to the more complicated cooling mode, depressurization through the ECCS vent valve, increase in decay heat rates, and moisture carryover out the vent valve, a linear change in operator response time was not seen for these events.

It is noted that the quantification methods used to assess Human Failure Events (HFEs) in the fire portion of the power uprate risk assessment are the same as those used in the original fire portion of the ANO-2 IPEEE analysis. These methods are described in Section 3.4.3 of Entergy's letter dated August 28, 1992, "ANO-2 Individual Plant Examination for Severe Accident Vulnerabilities." The quantification technique was developed for ANO by SAIC, the prime vendor supporting the ANO-2 individual plant examination analysis. This technique is nearly identical to that described as SHARP1. The primary quantification technique, the Human Cognitive Reliability (HCR) model is a Time Reliability Correlation system.

It is also noted that the assessment of HFEs in the internal events analysis portion of the power uprate risk assessment involved a compilation of state of the art Human Reliability Analysis methods. The approach incorporates the elements described in Regulatory Guide 1.174 and meets the expectations for a quality human reliability analysis as stated in draft NUREG-1560, "Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance." Pre-initiator human errors (Type A HFEs) were quantified via a simplified form of the Technique for Human Error Rate Prediction (THERP) developed for the Accident Sequence Evaluation Program (ASEP). Proceduralized post-initiator human errors (Type C_P HFEs) were quantified via two complementary approaches: (1) the HCR correlation developed by EPRI, incorporating data from the Operator Reliability Experiments, described in the EPRI reports NP-6560L, "A Human Reliability Analysis Approach Using Measurements for Individual Plant Examinations," (December 1989) and TR-100259, "An Approach to the Analysis of Operator Actions in Probabilistic Risk Assessment," (June 1992) and (2) the cause-based methodology developed by EPRI and documented in the report TR-100259. The larger of the two results was used in the probabilistic safety assessment analysis. Non-proceduralized post-initiator human errors (Type C_R HFEs) were quantified via a revised Systematic Human Action Reliability Procedure (SHARP) developed by EPRI in TR-101711, Tier 2, ""A Revised Systematic Human Action Reliability Procedure" (December 1992). Dependencies between Post-Initiator HFEs were accounted for via use of the revised Systematic Human Action Reliability Procedure developed by EPRI in TR-101711, Tier 2.

1448 S. R. 333
Russellville, AR 72802

**ARKANSAS NUCLEAR ONE
ENTERGY OPERATIONS**

Fax

To:	Tom Alexion	From:	Dennis Boyd
Fax:		Date:	10/4/01
Phone:		Pages:	5
Re:		CC:	

☐ Urgent ☐ For Review ☐ Please Comment ☐ Please Reply ☐ Please Recycle

•Comments:

Draft response to Question 10 from the Rx Systems Branch second RAI. Per our conversation, the response to Question 10 references our response to Question 15 from the Rx Systems Branch first RAI. I attached it also (in draft form)

Dennis

Please address the following areas regarding the reactor coolant pump (RCP) shaft seizure accident described in Section 7.3.5:

a) Explain why a concurrent loss of offsite power is not assumed with a RCP shaft seizure.

b) Describe the method used to determine the amount of failed fuel and state the number of failed fuel in this event.

ANO Response

a) A concurrent loss of off-site power was not considered in the original licensing analyses for ANO-2; hence, it was not considered during the power uprate effort.

b) The methods used to determine the amount of failed fuel is defined in Section 7.3.5.2.4. Although, the Cycle 16 reload efforts are not complete at this time, it will be verified that the total fuel failures will be less 14%. The results in Figure 7.3.5.2-6, which present minimum DNBR for fuel pins of various radial peaks, will be used to determine the number of pin failures.

NRC Question 9

Provide the methods used in determining the allowable power level with inoperable main steam safety valves.

ANO Response

The methods used to determine the allowable power level with inoperable main steam safety valves is defined in Section 1.4.1 of Enclosure 4 to our letter dated November 29, 1999 (2CAN119901). The methods and analyses presented in the November 29, 1999, letter are utilized to define the new allowable power levels. Technical specification Table 3.7.1 and Figure 3.7-1 are based on a percentage of rated thermal power. Each of the data points in Table 3.7.1 and Figure 3.7-1 of the technical specifications is supported by an explicit evaluation of the loss of condenser vacuum event based on an initial thermal power. The technical specification limits reflect the ratio of the analysis assumed initial thermal power to the rated thermal power. No new analyses were performed to support power uprate. The proposed technical specification Table 3.7.1 and Figure 3.7-1 limits are developed from the initial thermal power assumptions for the analyses discussed in the November 29, 1999, letter and adjusted by the uprated power level.

NRC Question 10

Please address the following areas regarding the feedwater line break accident analysis described in Section 7.3.11.2:

a) *Explain the need for the change in methodology for determining the most limiting break size. Provide discussion on why the feedwater line break analysis submitted by your letter dated November 29, 1999 (Enclosure 4, Page 40 of 172) is no longer valid.*

b) *Explain why the proposed method would [be] able to determine a most limiting break size which could bound the spectrum of potential break sizes including a double ended main feedwater line break.*

c) *Is the proposed method of determining the most limiting feedwater line break size consistent with that used in the Combustion Engineering (CE) System 80+ design? Has the proposed method been applied in any other CE-designed pressurized water reactors? Provide the citation for staff approval of the revised methodology and its applicability to ANO-2.*

d) *Discuss the instrument used in the RPS to initiate a reactor trip on low water level (with 40,000 lbs of water remaining) in the failed steam generator. Is this level measurement reliable during the dynamic transient conditions of a steam generator?*

e) *Discuss the single failure assumed in the feedwater line break analysis.*

ANO Response

a) The only change in determining the limiting break size relates to the new assumption of crediting the low level trip in the affected steam generator. Not crediting the low level setpoint in the affected steam generator will result in a limited range of feedwater line breaks potentially overfilling the pressurizer. As a result of this new method break spectrum was assessed. Additionally, the analysis for the replacement steam generator effort was not performed at the uprated power level. The new break size of 0.1492 ft^2 is only slightly smaller than the current limiting break size of 0.1798 ft^2 assumed in the replacement steam generator effort.

b) We have looked at a range of break sizes as shown in Figure 7.3.11.2-1 demonstrating the bounding nature of the smaller break sizes.

c) See the response to Question 15 in our letter dated XXXXX (2CAN100110).

d) See the response to Question 15 in our letter dated XXXXX (2CAN100110).

e) A single failure of an emergency feedwater pump is assumed consistent with the current analysis assumptions.

NRC Question 11

NRC Question 13

Please provide the initial steam generator mass and the basis for that value for all Chapter 15 transient and accident analyses.

ANO Response

The initial steam generator mass is calculated by CENTS based on the event specific defined RCS initial conditions (temperature, pressure and flow) and the initial steam generator level. All Chapter 15 events are based on 70% indicated level at hot full power conditions and 60% level at hot zero power conditions. The one exception is the feedwater line break analysis which is based on an inventory of 164,400 lbm. For this event a more conservative inventory based on the high level alarm limit of 78% was assumed.

PULR Section 7.3.11.2 – Feedwater Line Break Accident

NRC Question 14

Provide the location of the feedwater line inlet in your steam generator.

ANO Response

The centerline of the inlet nozzle is 361" above the top of the tubesheet. SAR Figure 5.5-7 (Amendment 16) shows the relative position of the elevated feed ring. The J nozzle outlet is 386" above the top of the tubesheet.

NRC Question 15

Justify that the low level trip occurs with at least 40,000 pounds mass (lbm) of liquid remaining in the faulted steam generator (page 7-135 of the PULR). The justification should be based on the accuracy of the instrumentation under the conditions and the physics of two phase flow. What is the impact of not being able to take credit for this trip?

ANO Response

The instrument uncertainty calculations have taken into consideration the steam generator conditions when determining the mass of inventory in the steam generator at time of trip. The blowdown effects of density changes and velocities following a feedwater line break (FWLB) have been accounted for. An inventory of 40,000 lbm credited in the FWLB is conservative with respect to the approximate 78,000 lbm at the low level trip setpoint credited in the loss of feedwater analysis.

Credit for low level indication during a FWLB on the affected steam generator is similar to the credit taken by Westinghouse plants as presented in WCAP 9230, "Report on the Consequences of a Postulated Main Feedline Rupture" (January 1978) and WCAP 9236, "NOTRUMP: A Nodal Transient Steam Generator and General Network Code" (September 1977). The replacement steam generators for ANO-2 are Westinghouse designed steam generators.

The 40,000 lbm was determined consistently and conservatively with the methods documented in WCAP 9230 and WCAP 9236 using the NOTRUMP code. This 40,000 lbm assumption was then used in the CENP CENTS code for determination of the effects on the reactor coolant system versus the Westinghouse LOFTRAN code.

Not crediting the low level setpoint in the affected steam generator will result in a limited range of feedwater line breaks potentially overfilling the pressurizer.

10 CFR 50.62 – Anticipated Transients Without Scram (ATWS)

NRC Question 16

Please submit an analysis of an ATWS at the uprated power level to show that peak pressures and the percentage of cycle with an unfavorable moderator temperature coefficient are consistent with those considered by the staff in deliberations leading to promulgation of the ATWS rule.

ANO Response

The ATWS Rule, 10CFR50.62, required that the ANO-2 design be modified to include a diverse scram system (DSS), diverse turbine trip (DTT) and diverse emergency feedwater actuation system (DEFAS). Paragraph (c)(2) of the rule required the installation of a DSS system for Combustion Engineering and Babcock and Wilcox manufactured plants. These system designs were approved by the NRC in safety evaluations dated June 21, 1989 (2CNA068902) and May 1, 1990 (2CNA059001) based on their reliability, independence and diversity from the plant protection system. Power uprate does not modify the DSS, DTT or DEFAS designs, and therefore, these systems continue to comply with the ATWS Rule. Consistent with the respective safety evaluations approving these designs, the actuation setpoint for DSS/DTT remains above the reactor protection system high pressurizer pressure setpoint and below the pressurizer safety valve opening set pressure. The actuation setpoint for DEFAS is below the plant protection system setpoint for the emergency feedwater actuation system. The ATWS Rule imposed system design requirements, but ATWS events did not become design basis events requiring re-analysis.

Followup Request for Additional Information on
Mechanical and Civil Engineering Issues
Extended Power Uprate License Amendment Application
Arkansas Nuclear One, Unit 2

1. Discuss the effect of the power uprate on differential pressure, flow, temperature, and system pressure on safety-related air-operated valve (AOV) and motor-operated valve (MOV) functions.

2. Discuss the necessary revision of the AOV and MOV capability calculations such as any changes in valve factor or Electric Power Research Institute (EPRI) performance-prediction-methodology (PPM) application.

3. Discuss any loss of AOV or MOV capability margins from the power uprate, and any planned short-term or long-term actions to restore margins.

4. The licensee states that the evaluation of the effect of the power uprate regarding Generic Letter (GL) 95-07 will be completed on September 30, 2001. Discuss the potential for thermal binding or pressure locking, such as caused by temperature increases, on the scope of power-operated valves under GL 95-07 or the performance of those valves. Discuss any modifications or procedure changes necessary as a result of the power uprate to preclude thermal binding and pressure locking. The licensee will need to submit an update of its August 23, 2001, letter notifying the NRC of the completion of the GL 95-07 review and its results.

From: "Spike Ford" <Spike_Ford@pgn.com>
To: <djw1@nrc.gov>
Date: 10/11/01 11:44AM
Subject: Phase 2 Groundwater Monitoring Plans

Dave -

Enclosed are site maps showing the proposed locations for the phase 2 groundwater monitoring wells (PDF files) and a summary of the analytical results from phase 1 monitoring program samples (excel file). I am also faxing copies of the draft well logs from the phase 1 drilling. Please note that these documents are all in the draft stage and are being provided to support discussion regarding phase 2 of the groundwater monitoring program. Thank You

Spike Ford

CC: "Lanny Dusek" <LANNY_DUSEK@pgn.com>, "Spike Ford" <SPIKE_FORD@pgn.com>, "Tom Meek" <TOM_MEEK@pgn.com>

Mail Envelope Properties (3BC5BE51.9DA : 17 : 18906)

Subject:	Phase 2 Groundwater Monitoring Plans
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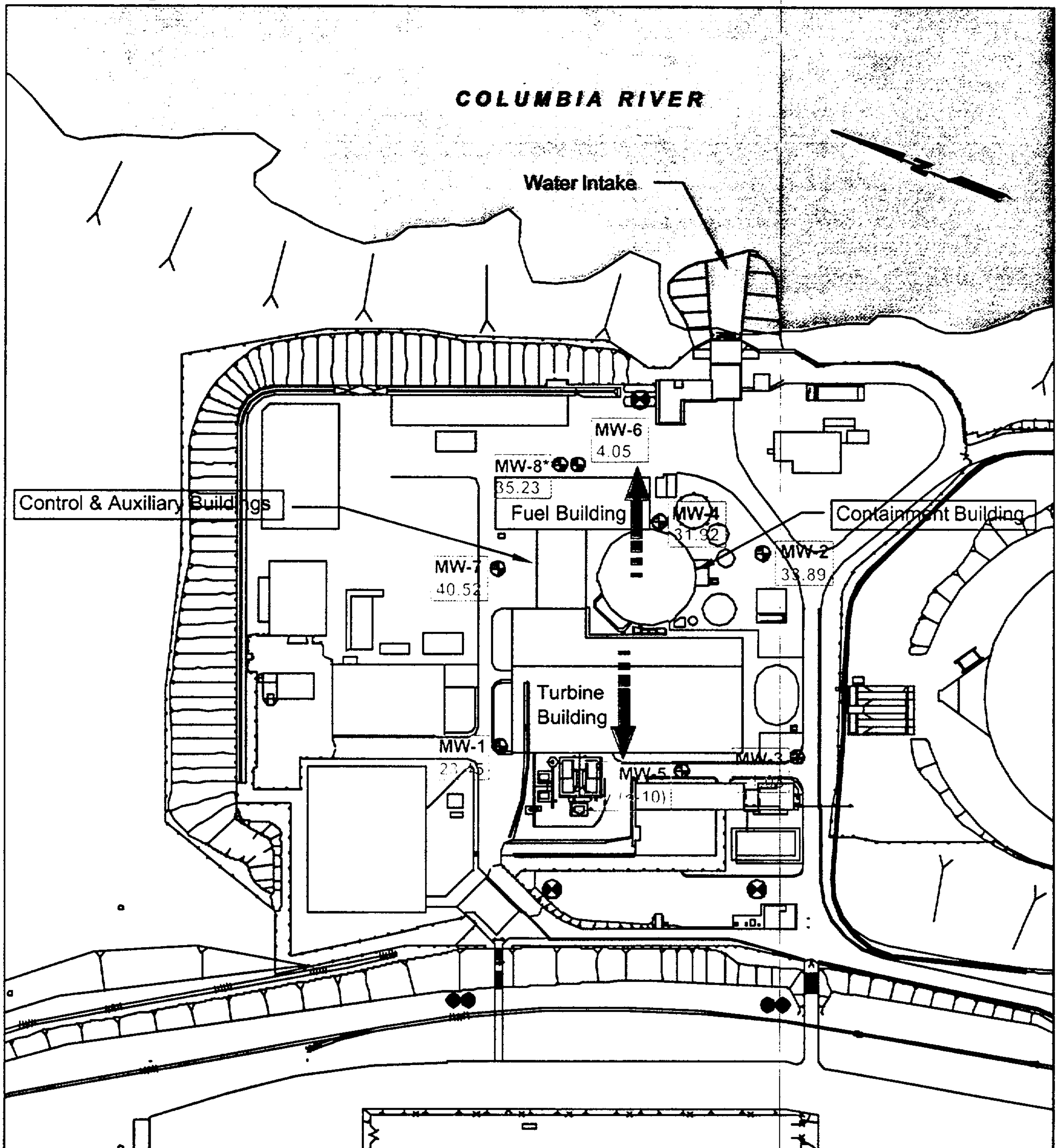
Trojan Nuclear Plant
Rainier, Oregon

DRAFT



Notes: (1) Base map prepared from an AutoCAD file provided by PGE. (2) *All wells screened at approximately the same interval (+10 to -10 feet MSL), except MW-8 which is screened at 25 to 35 feet MSL.

Legend:

MW-1 ⊕	Monitoring Well Location and Designation
23.35	Groundwater Elevation in Feet Above Mean Sea Level (MSL): August 9, 2001
▪▪▬▶	General Groundwater Flow Direction
●●	Proposed Nested Monitoring Well Location
⊗	Proposed Shallow Monitoring Well Location

0 200 400

Approximate Scale in Feet

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15154-01 ***8/01***

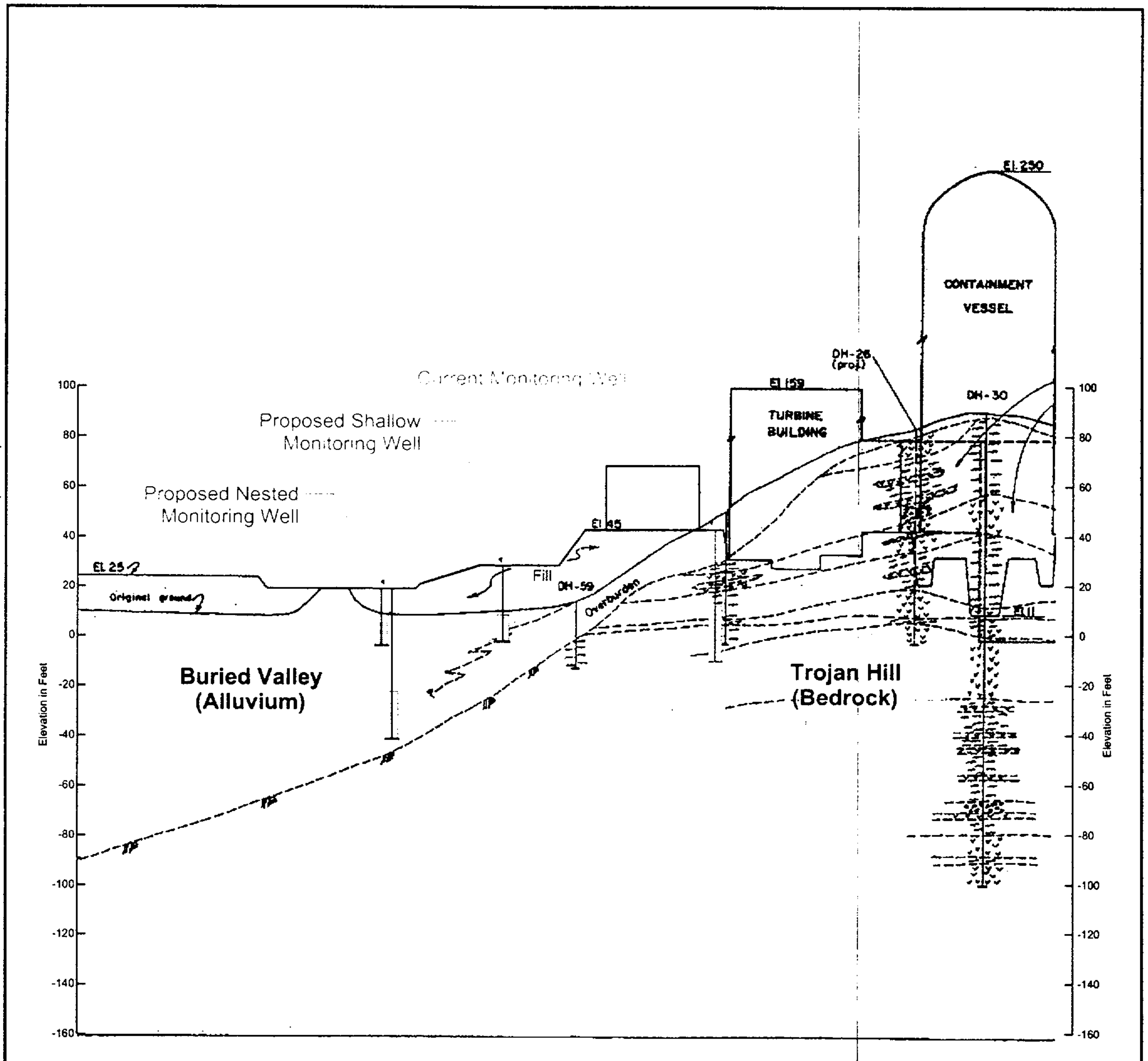
Figure 1

F:\DATA\Jobs\15154 Bridgewater - Trojan\Proposed Wells 15154-01\1515401 01 (Prop Wells)

JAB 1=1

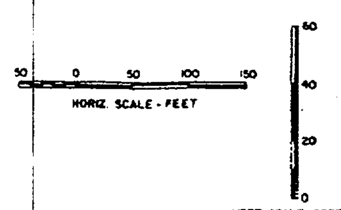
Cross Section with Proposed Monitoring Wells
Trojan Nuclear Plant
Rainier, Oregon

DRAFT



F:\DATA\Jobs\15154 Bridgewater - Trojan\Proposed Wells 15154-01\1515401 02 (X-Sect)

Note: Base cross section from Figure 2.5-5 of Final Safety Analysis Report for the Trojan Nuclear Plant.



Legend:

Monitoring Well

Screened Interval

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15154-01 8/01

Figure 2

Trojan well water analyses		(results in pCi/L)																						
			Tritium		Co-60		Cs-137		Fe-55	Ni-63	Sr-89	Sr-90	Am-241	Cm-243,244	Cm-242	Pu-238	Pu-239,240	Pu-241	U-238	U-235	U-234	Boron (mg/L)
Well #	ID #	pH	Trojan	Duke	Trojan	Duke	Trojan	Duke														
MW-1	135132-01	9.36	<395	<38	<14	<5.1	<13	<4.1	<16	<16	<8.8	<1.7	<0.33	<0.14	<0.16	<0.065	<0.043	<6.7	0.126	<0.073	0.108	2.450
MW-2	135133-01	9.42	<403	<38	<15	<4.4	<13	<3.9	<17	<12	<8.4	<1.8	<0.30	<0.12	<0.14	<0.084	<0.046	<8.6	0.236	<0.032	[illegible]	1.310
MW-3	135134-01	9.2	<403	<38	<14	<3.6	<12	<3.5	<18	<13	<7.0	<1.5	<0.30	<0.16	<0.18	<0.12	<0.064	<8.5	0.451	<0.058	0.536	2.120
MW-4	135135-01	9.23	<395	<38	<10	<4.2	<12	<3.5	<10	<12	<5.9	<1.2	<0.30	<0.12	<0.13	<0.035	<0.021	<9.9	0.138	<0.034	0.435	0.723
MW-5	135136-01	dry	dry	dry	dry	dry	dry	dry	dry	dry	dry	dry	dry	dry	dry	dry	dry	dry	dry	dry	dry	dry
MW-6	135137-01	9.5	<403	<38	<13	<7.1	<13	<6.1	<19	<14	<5.7	<1.2	<0.35	<0.21	<0.22	<0.054	<0.048	<7.2	0.269	<0.065	0.373	[illegible]
MW-7	135138-01	9.26	<395	<38	<11	<6.7	<13	<5.8	<14	<17	<6.1	<1.2	<0.37	<0.16	<0.18	<0.027	<0.016	<6.2	<0.058	<0.076	<0.065	1.450
MW-8	135181-01	8.17	2433	174	<13	<4.8	<12	<5.9	<16	<18	<7.8	<1.6	<0.43	<0.24	<0.22	<0.066	<0.035	<8.8	0.094	<0.068	[illegible]	[illegible]
MW-9	135139-01	8.23	<398	<38	<13	<5.9	<13	<4.8	<11	<15	<9.0	<1.8	<0.38	<0.16	<0.18	<0.033	<0.022	<6.3	0.711	<0.064	2.33	0.158
MW-10	135140-01	9.23	<403	<38	<13	<4.6	<12	<4.4	<19	<15	<6.6	<1.5	<0.36	<0.19	<0.17	<0.10	<0.061	<2.8	0.761	<0.051	1.25	0.210

red cells =results are above background

green cells are positive results that are background

MW-5 was dry therefore no analyses performed

Spent Fuel pool tritium concentration

08/13/2001 2.76E7 pCi/L
09/10/2001 2.68E7 pC/L

TROJAN NUCLEAR PLANT
71760 COLUMBIA RIVER HWY.
RAINIER, OREGON 97048

C O V E R

S H E E T

FAX

To: Dave Wrona

From: SPIKE FORD

Subject: Phase 2 Groundwater Monitoring

Date: 10-11-2001

Pages: 12 + Cover

COMMENTS:

If you have any difficulty with this transmission please contact:

Pat Schaffran
503-556-7529
Fax: 503-556-7002

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MEMORANDUM

DATE: October 10, 2001

TO: Tom Meek, PGE

FROM: Rick Ernst, Hart Crowser

RE: **Draft Monitoring Well Logs**
Trojan Nuclear Plant, Rainier, Oregon
15154-01

CC: Stu Brown, Bridgewater Group

Attached are draft versions of logs for the monitoring well logs installed at the Trojan Nuclear Plant in July 2001. These logs show subsurface geological conditions and well construction details. The following information should be considered when reviewing these logs.

- Drill cuttings were used to describe subsurface geological conditions. Due to the relatively "soft" nature of the bedrock, the air rotary drill rig pulverized the bedrock, which precluded detailed identification of geologic strata. Based on cores taken prior to plant construction, bedrock consists of layers of tuffs, flow breccias, and basalt. We have generally described bedrock based on drill action (i.e., easy or hard drilling) and color.
- Indications of moisture (e.g., dry, damp, moist, or wet) were based on perceived moisture content of the drill cuttings. As moisture increased, the fine particles would adhere together as "clumps." To the extent practicable, drilling was performed dry. For several wells, water was added to cool the drill bit. If water was added, it is noted on the logs. From thereon, natural moisture content could not be ascertained.
- Surface elevations are approximate. PGE will be surveying the elevations of the well top of casings and monuments.
- Groundwater elevations on the logs were measured during the August 9, 2001, groundwater monitoring event.

Five Centerpointe Drive, Suite 240
Lake Oswego, Oregon 97035-8652
Fax 503.620.6918

Key to Exploration Logs

DRAFT

Sample Descriptions

Classification of soils in this report is based on visual field and laboratory observations which include density/consistency, moisture condition, and grain size, and should not be construed to imply field nor laboratory testing unless presented herein. Visual-manual classification methods of ASTM D 2488 were used as an identification guide.

Soil descriptions consist of the following:
Density/consistency, moisture, color, minor constituents, MAJOR CONSTITUENT with additional remarks.

Density/Consistency

Soil density/consistency in borings is related primarily to the Standard Penetration Resistance. Soil density/consistency in test pits and push probe explorations is estimated based on visual observation and is presented parenthetically on test pit and push probe exploration logs.

SAND and GRAVEL Density	Standard Penetration Resistance in Blows/Foot
Very loose	0 - 4
Loose	4 - 10
Medium dense	10 - 30
Dense	30 - 50
Very dense	>50

SILT or CLAY Density	Standard Penetration Resistance in Blows/Foot	Approximate Shear Strength in TSF
Very soft	0 - 2	<0.125
Soft	2 - 4	0.125 - 0.25
Medium stiff	4 - 8	0.25 - 0.5
Stiff	8 - 15	0.5 - 1.0
Very Stiff	15 - 30	1.0 - 2.0
Hard	>30	>2.0

Moisture

Dry	Little perceptible moisture.
Damp	Some perceptible moisture, probably below optimum.
Moist	Probably near optimum moisture content.
Wet	Much perceptible moisture, probably above optimum.

Minor Constituents

Minor Constituents	Estimated Percentage
Not identified in description	0 - 5
Slightly (clayey, silty, etc.)	5 - 12
Clayey, silty, sandy, gravelly	12 - 30
Very (clayey, silty, etc.)	30 - 50

Legends

Sampling Symbols

BORING AND PUSH PROBE SYMBOLS

- Split Spoon
- Tube (Shelby, Push Probe)
- Cuttings
- Core Run
- Temporarily Screened Interval
- N Standard Penetration Resistance
- * No Sample Recovery
- PID Photoionization Detector Reading

TEST PIT SOIL SAMPLES

- Grab (Jar)
- Bag
- Shelby Tube

Groundwater Observations and Monitoring Well Construction

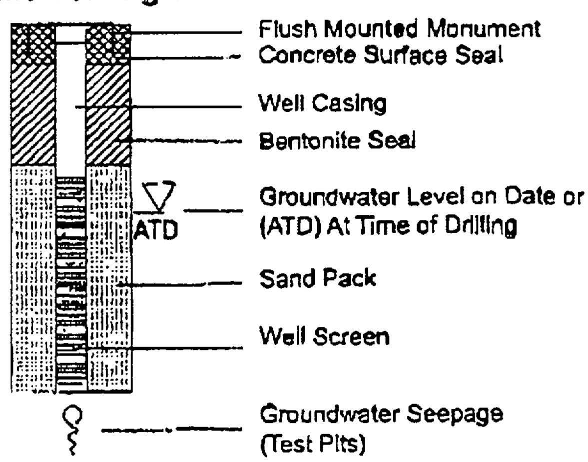

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Figure A-1

Monitoring Well Log MW-1

DRAFT

Soil Descriptions

(Medium stiff), damp, brown, slightly silty SAND (FILL).

Becomes moist.

Damp, blue-gray BEDROCK (Easy drilling).

Becomes gray.

Becomes blue-gray.

Becomes gray.

Becomes dry.

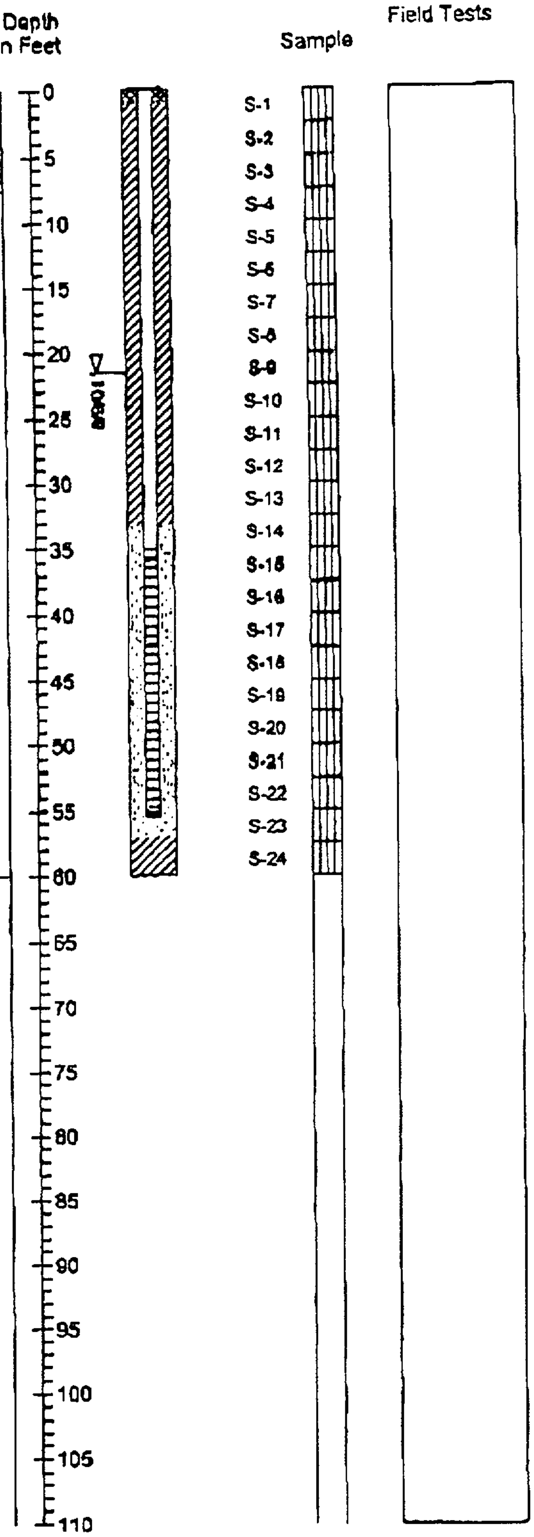
Becomes green.

Becomes gray.

Becomes light gray.

Bottom of Boring at 60.0 Feet.
Completed 7/23/01.

Start Card: #135132
Well ID: #L49987
Casing Stickup in Feet
Top of PVC in Feet
Inside Diameter of PVC: 2"



MW_15154.GPJ HC_CORP.GDT 10/10/01

1. Refer to Figure A-1 for explanation of descriptions and symbols.
2. Soil descriptions and stratum lines are interpretive and actual changes may be gradual.
3. Groundwater level, if indicated, is at time of drilling (ATD) or for date specified. Level may vary with time.
4. Approximate elevation: 45 feet MSL.

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Figure A-2

Monitoring Well Log MW-2

DRAFT

Soil Descriptions

Gravel surface.

Dry, dark gray BASALT (Bedrock). (Hard drilling).

Dry, dark gray, green, and light gray layers of BEDROCK (Easy drilling).

Becomes dark gray.

Becomes moist.

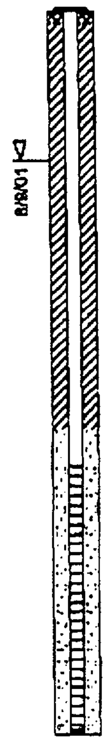
Thin zone of groundwater. Thereafter becomes dry.

Bottom of Boring at 55.0 Feet.
Completed 7/23/01.

Start Card: #135133
Well ID: #L49986
Casing Stickup in Feet:
Top of PVC in Feet:
Inside Diameter of PVC: 2"

Depth in Feet

0, 5, 10, 15, 20, 25, 30, 35, 40, 45, 50, 55, 60, 65, 70, 75, 80, 85, 90, 95, 100, 105, 110



Sample

S-1, S-2, S-3, S-4, S-5, S-6, S-7, S-8, S-9, S-10, S-11, S-12, S-13, S-14, S-15, S-16, S-17, S-18, S-19, S-20, S-21, S-22

Field Tests

MW_15154.GPJ HC_CORP.GDT 10/4/01

1. Refer to Figure A-1 for explanation of descriptions and symbols.
2. Soil descriptions and stratum lines are interpretive and actual changes may be gradual.
3. Groundwater level, if indicated, is at time of drilling (ATD) or for date specified. Level may vary with time.
4. Approximate elevation: 45 feet MSL.

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Figure A-3

Monitoring Well Log MW-3

DRAFT

Soil Descriptions

Gravel surface.

(Loose), damp, brown SAND (FILL).

Dry to damp, gray BEDROCK (Easy drilling).

0.5-Foot-thick lens of green BEDROCK.

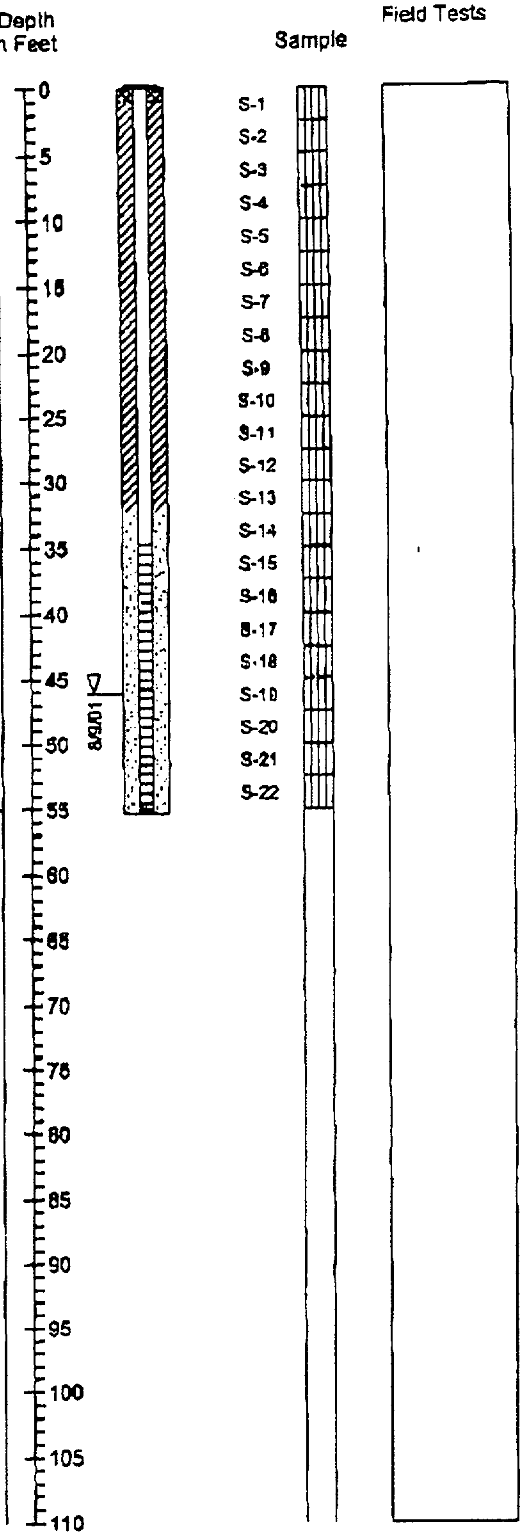
Hard drilling.

Easy drilling.

Hard drilling.

Bottom of Boring at 55.0 Feet.
Completed 7/23/01.

Start Card: #135134
Well ID: #L49989
Casing Stickup in Feet:
Top of PVC in Feet:
Inside Diameter of PVC: 2"



MW_15154.GPJ HC_CORP.GDT 10/10/01

1. Refer to Figure A-1 for explanation of descriptions and symbols.
2. Soil descriptions and stratum lines are interpretive and actual changes may be gradual.
3. Groundwater level, if indicated, is at time of drilling (ATD) or for date specified. Level may vary with time.
4. Approximate elevation: 45 feet MSL.

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Figure A-4

Monitoring Well Log MW-4

DRAFT

Soil Descriptions | Depth in Feet | Sample | Field Tests

6" Gravel over (loose), damp, brown SAND (FILL).

Damp, gray BEDROCK (Easy drilling).

Becomes moist.

Becomes wet (water present after drilling stopped for one hour).

Becomes dry.

Becomes damp.

Becomes maroon.

Becomes gray.

Becomes green.

Bottom of Boring at 45.0 Feet.

Completed 7/25/01.

Start Card: #135135

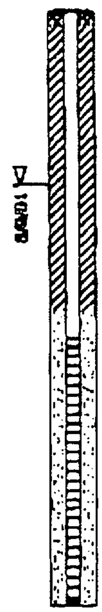
Well ID: #L49990

Casing Stickup in Feet:

Top of PVC in Feet:

Inside Diameter of PVC: 2"

Depth in Feet: 0, 5, 10, 15, 20, 25, 30, 35, 40, 45, 50, 55, 60, 65, 70, 75, 80, 85, 90, 95, 100, 105, 110



Sample: S-1, S-2, S-3, S-4, S-5, S-6, S-7, S-8, S-9, S-10, S-11, S-12, S-13, S-14, S-15, S-16, S-17, S-18

MW_15154.GPJ HC_CORP.GDT 10/10/01

1. Refer to Figure A-1 for explanation of descriptions and symbols.
2. Soil descriptions and stratum lines are interpretive and actual changes may be gradual.
3. Groundwater level, if indicated, is at time of drilling (ATD) or for date specified. Level may vary with time.
4. Approximate elevation: 45 feet MSL.

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Figure A-5

Monitoring Well Log MW-5

DRAFT

Soil Descriptions

6" Asphalt over base GRAVEL.
(Loose), damp, brown SAND (FILL).

(Loose), moist, brown, silty SAND.

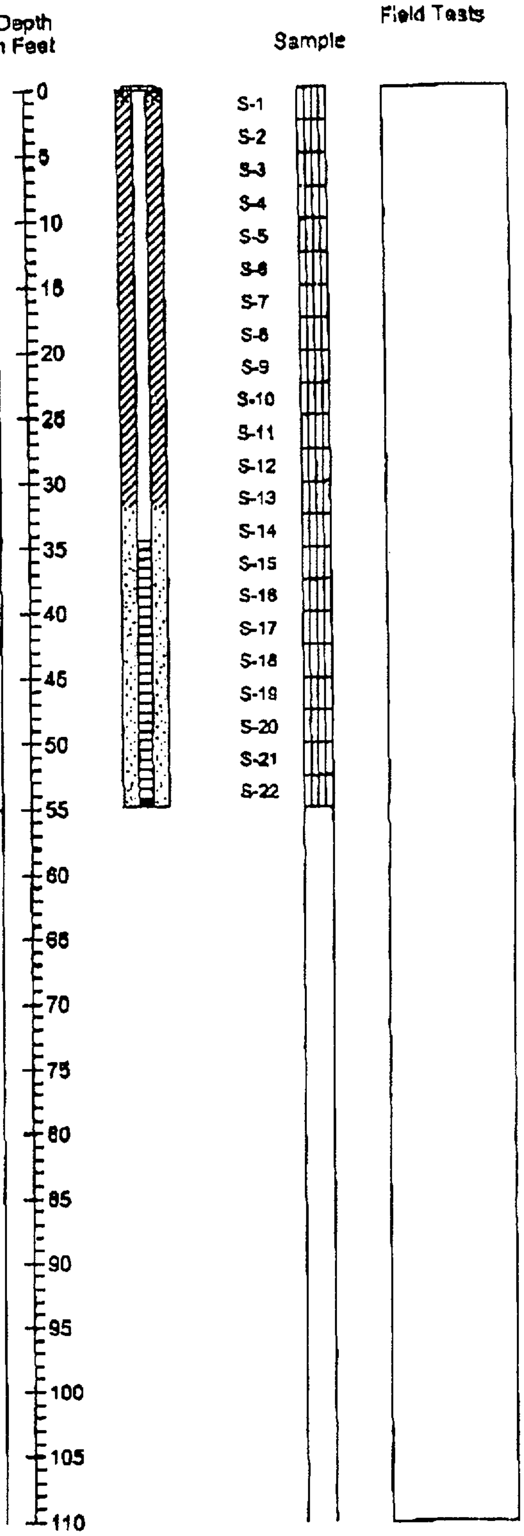
Damp, dark gray BEDROCK (Easy drilling).

Becomes dry. Hard drilling.

Becomes damp. Easy drilling.

Bottom of Boring at 55.0 Feet.
Completed 7/25/01.

Start Card: #135136
Well ID: #L49991
Casing Stickup in Feet:
Top of PVC in Feet:
Inside Diameter of PVC: 2"



1. Refer to Figure A-1 for explanation of descriptions and symbols.
2. Soil descriptions and stratum lines are interpretive and actual changes may be gradual.
3. Groundwater level, if indicated, is at time of drilling (ATD) or for date specified. Level may vary with time.
4. Approximate elevation: 45 feet MSL.
5. No groundwater present in well.

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15154-01 *7/01*

Figure A-6

Monitoring Well Log MW-6

DRAFT

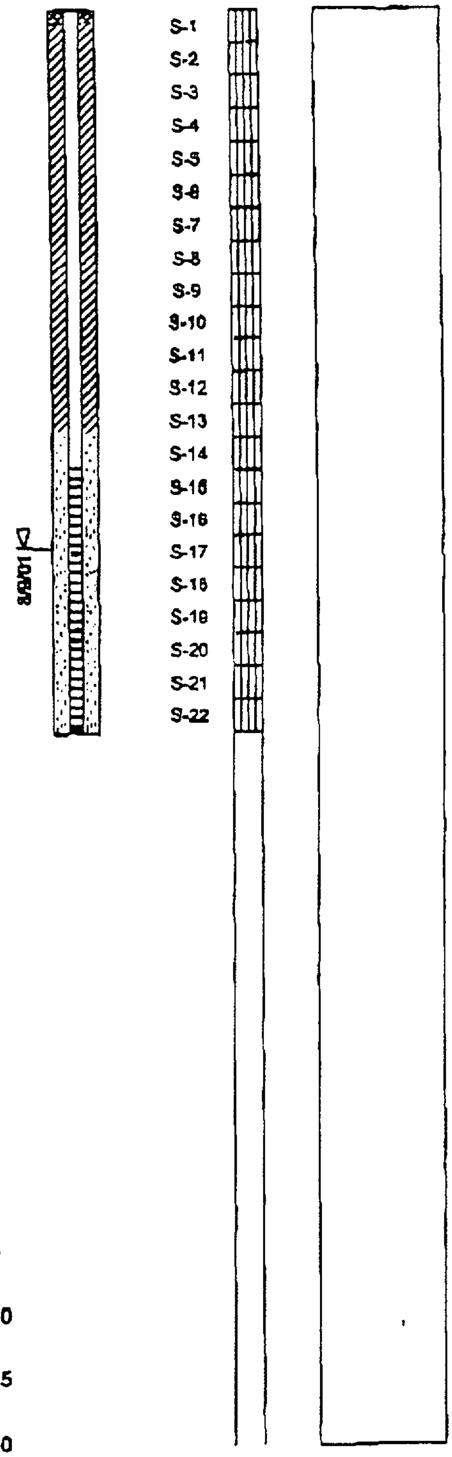
Soil Descriptions

6" Asphalt over base GRAVEL.
Damp, gray BEDROCK (Easy drilling).
Becomes dry. Hard drilling.
Becomes damp. Easy drilling.
Water added during drilling for remainder of borehole.
Becomes maroon.
Becomes gray.

Bottom of Boring at 55.0 Feet.
Completed 7/25/01.

Start Card: #135137
Well ID: #L49992
Casing Stickup in Feet:
Top of PVC in Feet:
Inside Diameter of PVC: 2"

Depth in Feet: 0, 5, 10, 15, 20, 25, 30, 35, 40, 45, 50, 55, 60, 65, 70, 75, 80, 85, 90, 95, 100, 105, 110



MW 1515A.GPJ HC CORP.GDT 10/10/01

1. Refer to Figure A-1 for explanation of descriptions and symbols.
2. Soil descriptions and stratum lines are interpretive and actual changes may be gradual.
3. Groundwater level, if indicated, is at time of drilling (ATD) or for date specified. Level may vary with time.
4. Approximate elevation: 45 feet MSL.

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Figure A-7

Monitoring Well Log MW-7

DRAFT

Soil Descriptions

Surface GRAVEL.
(Loose), damp, brown SAND (FILL).

Moist, gray BEDROCK (Easy drilling).

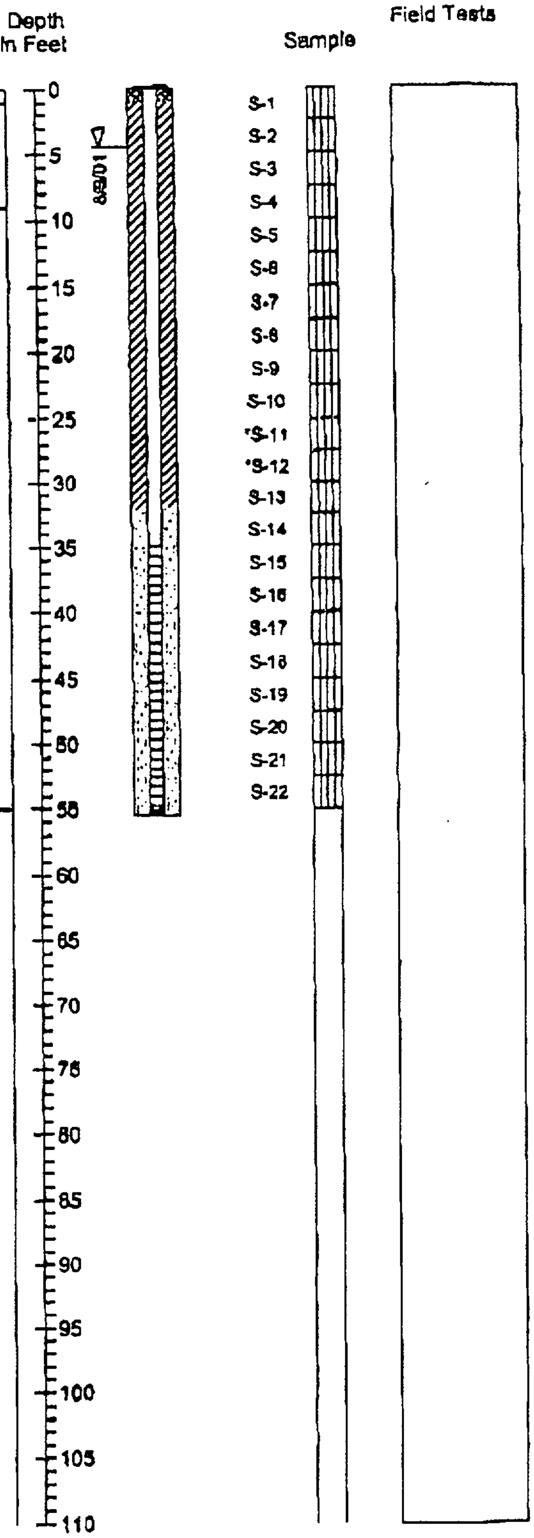
Water added during drilling for remainder of borehole.

Becomes maroon.
Becomes gray.

Becomes maroon.
Becomes gray.

Bottom of Boring at 55.0 Feet.
Completed 7/26/01.

Start Card: #135138
Well ID: #L49993
Casing Stickup in Feet:
Top of PVC in Feet:
Inside Diameter of PVC: 2"



MW 15154.GPJ HC_CORP.GDT 10/10/01

1. Refer to Figure A-1 for explanation of descriptions and symbols.
2. Soil descriptions and stratum lines are interpretive and actual changes may be gradual.
3. Groundwater level, if indicated, is at time of drilling (ATD) or for date specified. Level may vary with time.
4. Approximate elevation: 45 feet MSL.

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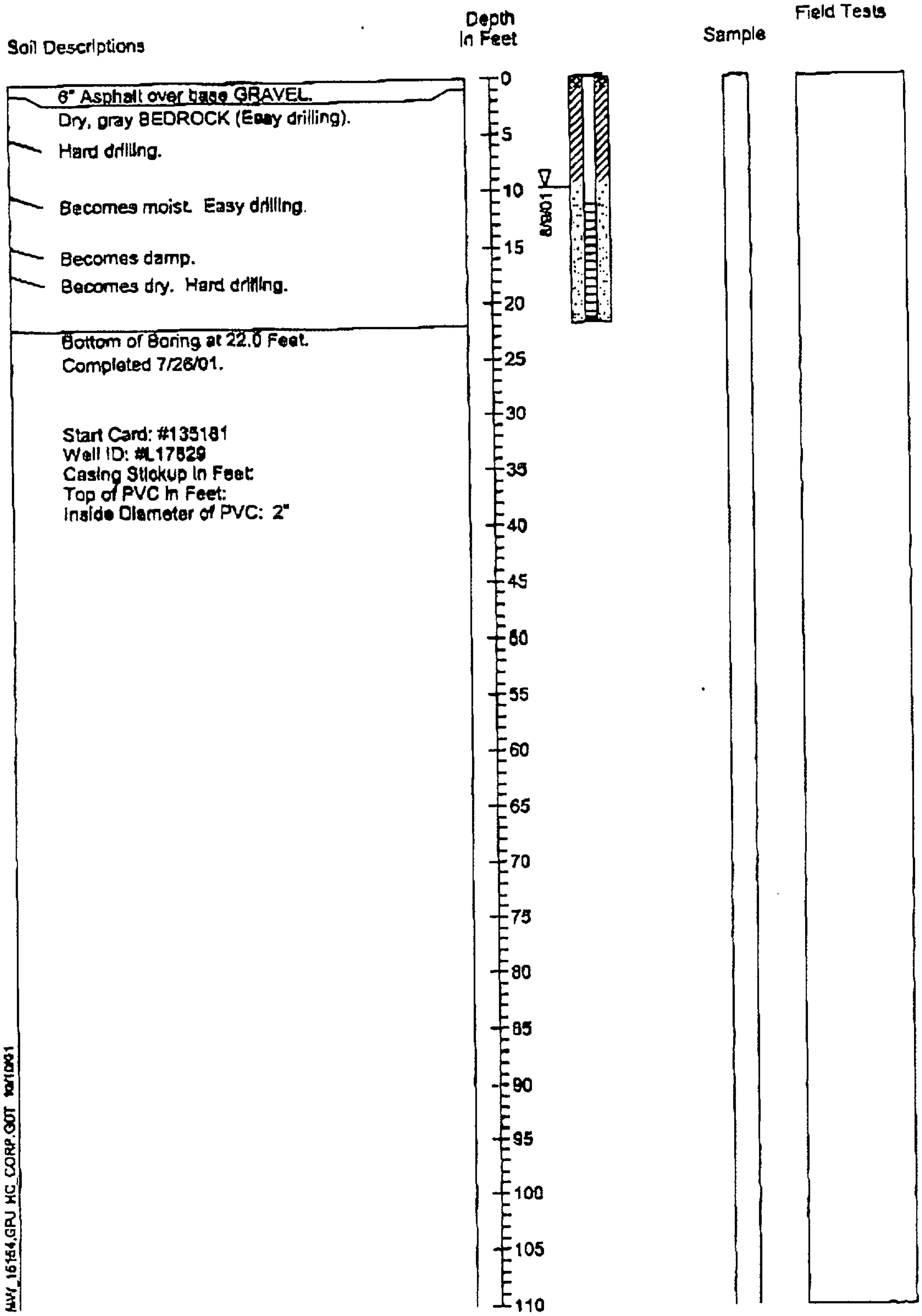
Figure A-8

Monitoring Well Log MW-8

DRAFT



1. Refer to Figure A-1 for explanation of descriptions and symbols.
2. Soil descriptions and stratum lines are interpretive and actual changes may be gradual.
3. Groundwater level, if indicated, is at time of drilling (ATD) or for date specified. Level may vary with time.
4. Approximate elevation: 45 feet MSL.

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Figure A-9

Monitoring Well Log MW-9

DRAFT

Soil Descriptions

3" Asphalt over base GRAVEL.

Dry to damp, maroon BEDROCK (Easy drilling).

Becomes gray.

Becomes maroon.

Becomes gray. Water added during drilling for remainder of borehole.

Becomes maroon.

Becomes gray.

Becomes maroon.

Becomes gray.

Becomes green.

Becomes maroon.

Becomes gray.

Hard drilling.

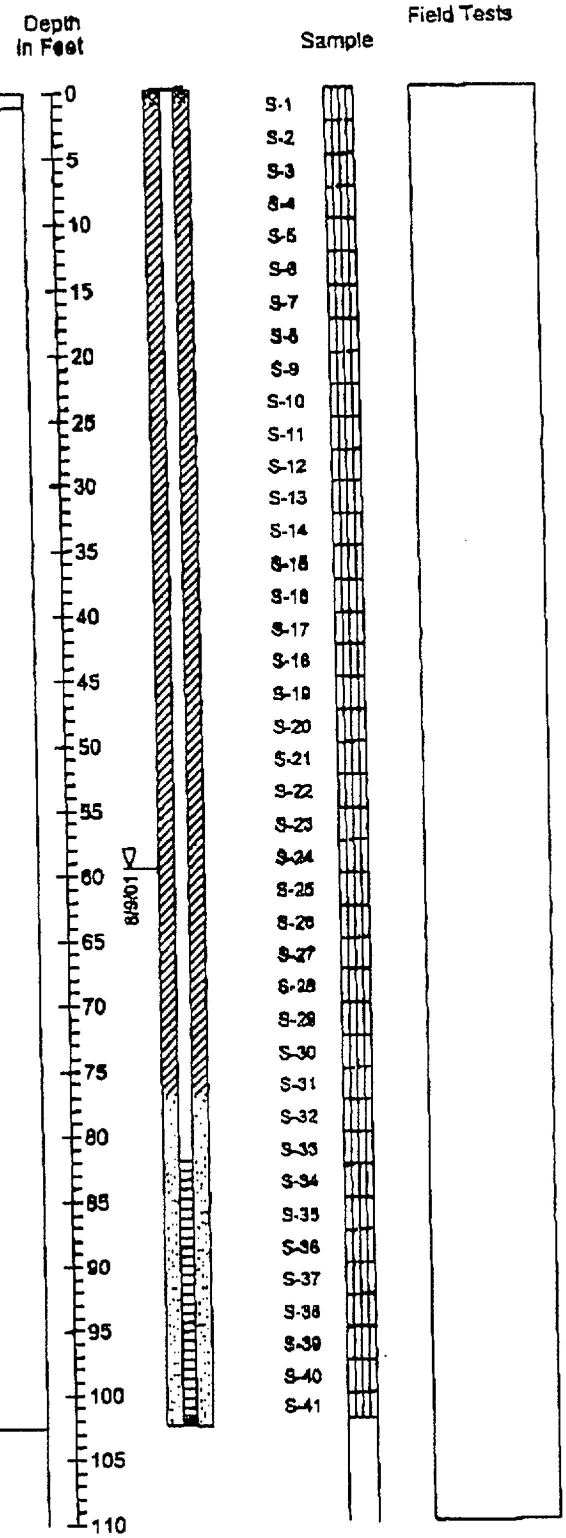
Easy drilling.

Becomes gray with white specks.

Becomes dark gray.

Becomes gray.

Bottom of Boring at 102.5 Feet.
Completed 7/27/01.



MW_15154.GPJ HC_CORP.GDT 10/9/01

Start Card: #135139
Well ID: #L49994
Casing Stickup in Feet:
Top of PVC in Feet:
Inside Diameter of PVC: 2"

1. Refer to Figure A-1 for explanation of descriptions and symbols.
2. Soil descriptions and stratum lines are interpretive and actual changes may be gradual.
3. Groundwater level, if indicated, is at time of drilling (ATD) or for date specified. Level may vary with time.
4. Approximate elevation: 92 feet MSL.

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Figure A-10

Monitoring Well Log MW-10

DRAFT

Soil Descriptions

(Medium stiff), moist, brown SILT.

Dry, gray BEDROCK (Hard drilling).

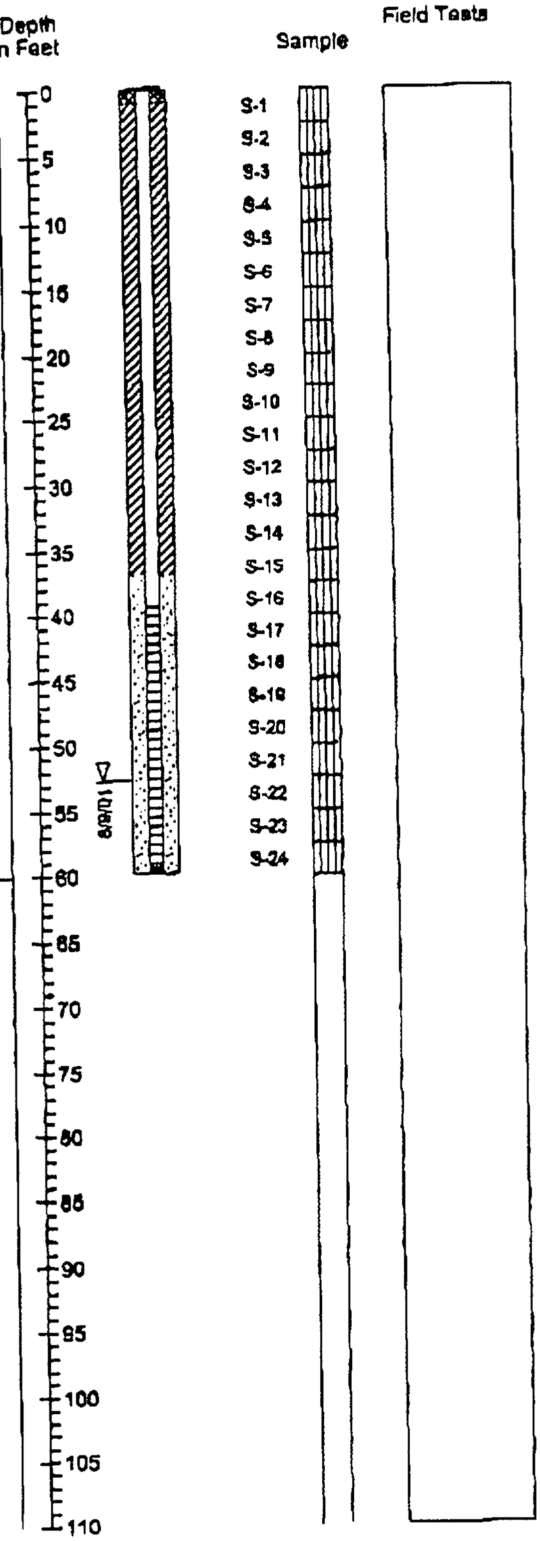
Becomes damp and maroon.
Becomes gray. Easy drilling.

1-Foot-thick maroon zone.
1-Foot-thick layer of dry, gray BEDROCK (Hard drilling).

1.5-Foot-thick layer of dry, light gray BEDROCK (Hard drilling).

0.5-Foot-thick maroon zone.

Bottom of Boring at 60.0 Feet.
Completed 7/27/01.



MW_15154.GPJ HC_CORP.GDT 10/10/01

1. Refer to Figure A-1 for explanation of descriptions and symbols.
2. Soil descriptions and stratum lines are interpretive and actual changes may be gradual.
3. Groundwater level, if indicated, is at time of drilling (ATD) or for date specified. Level may vary with time.
4. Approximate elevation: 45 feet MSL.

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Figure A-11