U.S. NUCLEAR REGULATORY COMMISSION
REGION I

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Licensee:	PENNSYLVANIA POWER AND LIGHT COMPANY 2 NORTH NINTH STREET ALLENTOWN, PENNSYLVANIA 18101
Facility Name:	SUSQUEHANNA STEAM ELECTRIC STATION
Inspection Period:	April 30, 1996 through June 10, 1996
Inspectors:	M. Banerjee, Senior Resident Inspector B. McDermott, Resident Inspector C. Poslusny, NRR Project Manager R. Urban, Project Engineer
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EXECUTIVE SUMMARY

Susquehanna Steam Electric Station, Units 1 & 2
NRC Inspection Report 50-387/96-06, 50-388/96-06

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection; in addition, it includes the results of announced inspections by regional and NRR staff.

Operations

While reviewing a list of maintenance work requests, the inspector determined that in April the control room operators did not identify an abnormal reading of the fuel zone level recorder channel for four days. This is considered an isolated incident as the control room operators at Susquehanna have generally shown good familiarity and cognizance of control room instrument readings. The licensee's identification of inconsistency in the Final Safety Analysis Report and the plant Technical Specification on vessel level instrumentation was a good initiative.

During a Plant Operations Review Committee (PORC) meeting, the inspector observed good management oversight and PORC involvement in planning and reviewing the river water tie-in work for supplemental decay heat removal.

Good procedure compliance was observed during testing of the semi-automatic operation of the refueling platform. The inspector noted good supervisory involvement and communication.

Maintenance

The licensee-developed maintenance performance parameters provide an overall assessment of the effectiveness of the maintenance activities at Susquehanna. The licensee is revising certain performance goals for further improvement of the timeliness of completion of higher priority work. The licensee's effort to develop these performance parameters was a noteworthy effort. The licensee also developed a set of maintenance standards in four key areas involving work preparation, physical work, policies and programs, and human performances, which are expected to enhance assessment of maintenance.

Engineering

The licensee identified deviations from certain licensing basis assumptions that could potentially affect offsite dose calculations. The contribution of control rod drive system leakage to the offsite dose calculation, and impact of this leakage to the 30 day water seal assumed for certain primary containment penetrations had not been adequately considered. The licensee review is ongoing, and is considered adequate.

Nuclear System Engineering review of the turbine bypass valve operability determination did not identify the potential consequences of an inoperable fast acting solenoid on bypass system operability. Their operability determination was based on observed bypass valve motion, but did not confirm proper operation of the fast acting solenoid. Although additional testing four days later revealed acceptable valve performance, the inspector considered the timeliness of the licensee's response inadequate when compared with the Technical Specification (TS) allowed action time for valve inoperability.

A 10 CFR Part 21 notification issued by Rosemount indicated that some of their pressure transmitters were subject to failure due to hydrogen permeation into the sensor cell. The inspector concluded that the licensee's review of the Rosemount Part 21 notification on hydrogen permeability, and corrective actions were adequate. It involved sufficient verification to ensure the vendor identified the affected transmitter at Susquehanna.

Plant Support

The inspector concluded the licensee's actions to improve access/egress control and monitoring of personal items removed from the radiologically controlled areas properly addressed the concerns.

The failure to barricade access to a high radiation area was a violation of Technical Specifications. However, since this violation was identified by licensee staff, and appropriate and timely corrective actions were implemented, it is being treated as a Non-Cited Violation, consistent with the NRC Enforcement Policy.

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Report Details

Summary of Plant Status

Unit 1 was operated at or near 100% rated power throughout most of the inspection period. Short duration power decreases were made for rod pattern adjustments and routine turbine valve testing. During the weekend of May 25, 1996, a dual unit power reduction to 40% was made to limit evaporation of circulating water in support of a modification on the river water makeup line to the cooling towers.

Unit 2 was operated at 100% power throughout most of the inspection period. Short duration power reductions were made in support of routine turbine valve testing. The most significant reduction in power was made to support the river water makeup line modification noted above.

I. Operations

02 Operational Status of Facilities and Equipment[1]

02.1 Fuel Zone Level Monitor

a. Inspection Scope (71707)

The inspector reviewed corrective actions taken by the licensee after PP&L identified that a control room indication channel for the fuel zone level instrument was not correctly reading for four days.

b. Observations and Findings

On April 16, 1996, a control room operator noted that the control room fuel zone level recorder was reading mid scale, and the small mylar strip with the chart scale was missing. The fuel zone recorder is the division 1 indicator for reactor vessel level, and covers a range from the top of the active fuel to near the bottom of active fuel. During normal operating conditions, this instrument is expected to read upscale. A review of the strip chart showed that the recorder had been reading mid scale since April 12, 1996. On that date I&C had performed a calibration on the recorder.

At Susquehanna, various level instruments (narrow, wide, extended and fuel zone) are provided to cover the whole spectrum of the reactor vessel level for different plant conditions. However, the accident monitoring instrumentation TS does not identify which level instrumentation it applies to. The Updated Final Safety Analysis Report (FSAR) section 18.1.31.3.3 discusses water level as an indicator of inadequate core cooling. Section 7.5.1a.4.2.1 indicates the fuel zone

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[1]Topical headings such as 01, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

water level instrumentation provides vessel level from over the top of active fuel to near the bottom of active fuel, and is calibrated at saturated atmospheric conditions at which it is used. However, the FSAR section continues to say that the extended range and not the fuel zone level indication is used for post accident tracking. Section 7.5.2a.4.2 of the FSAR indicates that the wide range level instrumentation is used for post-accident tracking. Thus the FSAR is inconsistent. The inspector noted that the FSAR did not indicate that under certain accident conditions fuel zone level would be the only reliable level instrument.

The licensee, during their improved TS review, initiated a condition report (CR 96-0394) to clarify the current design/licensing basis requirements of vessel level monitoring instrumentation and the needed surveillance requirements to meet the TS. This Condition Report (CR) is currently being reviewed by the licensee for determining appropriate corrective actions. The licensee stated that the inconsistencies in the FSAR would be properly addressed during the submittal of the improved TS.

Throughout the time period that the fuel zone recorder was inoperable, a redundant control room instrument (level indicator) was operable and displaying the normal upscale reading for fuel zone level. The inspector noted that licensee's resolution of corrective actions for CR 0418 required the Operations Manager to review with each shift the need to check indicators for proper operation when restored to service. The inspector noted that licensee's resolution did not address the fact that the operators of multiple shifts were not cognizant that the fuel zone level indication on a control room main panel was not reading correctly for four days. The anomalous reading was not identified during multiple shift turn-overs between the operators. The licensee indicated that the operator response did not meet management expectations. The Operation Manager will reinforce this issue with the operators.

c. <u>Conclusions</u>

The inspector concluded that the control room operators missing the status of the fuel zone level recorder channel for four days was an isolated incident. This is because the control room operators at Susquehanna have generally shown good familiarity and cognizance of control room instrument readings. The licensee's identification of inconsistency in the FSAR and implementation of the TS on vessel level instrumentation was a good initiative.

02.2 <u>Refueling Platform Upgrade Project (71707)</u>

The inspector witnessed implementation of a portion of Test Procedure 181-001 relating to the semi-automatic operation of the refueling platform in the Unit 1 and Unit 2 spent fuel pools on May 21, 1996. The procedure included selection, via computerized controls (touch screen methodology), of the position of a stored dummy fuel assembly, lifting it with the fuel hoist and relocating it to a selected second position in the fuel pool where the dummy assembly was inserted. This was repeated a number of times within the Unit 1 pool, then the platform was manually moved to the Unit 2 pool and the procedure was repeated there. A problem arose in the Unit 2 test in that the resting place for the dummy assembly was about 2-3" off from the center of the desired position. This problem was attributed to incorrect coordinates for the software inputs for the Unit 2 pool, and was subsequently corrected.

The inspector noted the procedure involved use of three-part communication between the parties. The supervisor read each step to the operator, who in turn performed each function and repeated it back as it was performed. The supervisor documented completion of each step on the procedure check form being used. This process is expected to continue until all functions are checked out and verified. The system will be utilized during the upcoming outage in September. The inspector found that the procedure was closely and precisely followed, and noted good supervisory involvement and communication.

07 Quality Assurance in Operations

07.1 Corrective Action Team and PORC Meetings

a. Inspection Scope (71707)

The inspectors periodically attended Plant Operations Review Committee (PORC) and Corrective Action Team meetings, and observed management participation and oversight of the station corrective action process. The following observations pertain to PORC meeting No. 96-049, and the Correcting Action Team (CAT) meeting on May 23, 1996.

b. Observations and Findings

The presentation for Technical Specification (TS) change 96-007, concerning minimum critical power ratio (MCPR) safety limits in support of the installation of ABB Lead Use Assemblies (new fuel) during the 10th refueling outage for Unit 1, was reviewed by PORC without any significant questions during the presentation.

The second presentation to PORC addressed Temporary Procedure 009-006 for the tie-in of the river water makeup system to the supplemental decay heat removal system. Plans to hook up the tie-in hardware to the manhole cover near the north gate were discussed. The river water system maintains water level in the cooling tower basin that the circulating and service water pumps take suction from. To minimize impact on the cooling tower operation and chemistry conditions, power for both units was reduced during the weekend of May 25-26, thus providing a maximum work window of about 8-9 hours. Depressurization and draindown of the makeup system occurred to facilitate the tie-in modification, and both cooling tower basin water level and chemistry had to be closely monitored. Significant controls and precautions were established in the procedure to preclude fouling the condensers and plant shutdown due to loss of service water or circulating water that would cause a plant shutdown.

A duty manager and an activity manager were assigned to be present during the work to ensure that all precautions were maintained and contingencies were established. Questions from a PORC member about worst case scenarios were adequately addressed by the presenter, and the Operations Manager provided his overall perspective on the quality of the planning that had been done and the preparations by his staff in anticipation of the work process.

The inspector attended the CAT meeting on May 23 and noted good management participation, particularly in providing guidance and expectations on unavailability of the environmental monitoring composite sampling requirement of the TS.

c. <u>Conclusions</u>

The inspector concluded that good management oversight and PORC involvement were evident in planning and reviewing the river water tie-in work. Management participation at the CAT meeting was noted to be strong.

08 Miscellaneous Operations Issues (92700)

08.1 <u>(Closed) VIO 50-387/E94-22-01013 (Inspection Report 50-387/93-80)</u>: Two examples of failure to follow procedures during refueling resulted in a Severity Level III violation. A fuel bundle was incorrectly removed from the core, and then placed back in its original location contrary to the refueling procedure requirements.

The second example of the violation involved replacement of a damaged fuel grapple with a "non-Q" grapple in violation of the plant procedure that required a "Q" qualified grapple. Although a non-conformance report (NCR) was written to document the "non-Q" status of the grapple, loss of segregation control happened when the NCR tag was removed to prevent possible foreign material entry into the reactor cavity.

The licensee's review identified that flow pattern and mast bending resulted in grapple drift, and the bridge operator's sole reliance on the bridge encoder resulted in picking up the wrong fuel bundle. Poor communication between some of the involved personnel resulted in the procedure violation when the fuel bundle was returned to its core location instead of the fuel pool.

The inspector verified completion of the licensee's corrective actions, training given to the refueling bridge operators, and the necessary procedure upgrades to ensure correct grapple alignment. Additional procedure and program changes resulted in a better defined chain of command for refueling activities. NRC inspection reports 95-22 and 95-08 noted that during the last two refueling outages, refueling operations were conducted in a well-controlled manner, and procedures were followed with good management oversight and appropriate consideration of safety issues.

Regarding the second example, enhanced procedure controls were instituted regarding components released for installation that had NCRs associated with them, and for refueling bridge work. An engineering evaluation was performed to justify use of "non-Q" grapple, and the Updated FSAR was revised to reflect its non-seismic nature. The licensee also reviewed the open NCRs and did not identify any other non-Q equipment released for installation.

The inspector concluded that the licensee has taken appropriate corrective actions. This item is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62703)

The inspectors observed all or portions of the following work activities:

Maintenance Observations:

- TP-024-133 Deenergization of E Diesel Generator Auto Transfer Switch for Breaker Repair, May 7, 1996
- P51887 ESW Loop B Cooling to B Dx Unit Check Valve Inspection, May 9, 1996
- P61339 Diesel Generator A Lube Oil Cooler Cleaning and Inspection, May 16, 1996
- P60066 Diesel Generator A Pressure Indicators, May 17, 1996
- V63266 RCIC MOV Wiring Inspection for Heat Damage, May 30, 1996

Surveillance Observations:

- SI-258-303 Quarterly Calibration of Steam Dome Pressure, April 30, 1996
- SO-150-002 Quarterly RCIC Flow Verification, May 14, 1996
- SE-070-B09 18 Month SGTS HEPA and Charcoal Filter Test, May 15, 1996
- SO-252-002 HPCI Quarterly Flow Verification, June 5, 1996

b. Observations and Findings

The inspector found that the observed portion of the work was performed safely, work plans and procedures were followed, test equipment was within calibration period, foreign material exclusion measures were taken, radiation control measures were in place when specified, and the technicians were knowledgeable of their assigned tasks and appropriate level of supervisory attention was given to the work depending on its priority and potential impact.

M7 Quality Assurance in Maintenance Activities

M7.1 Maintenance Performance Indicators and Backlog

a. Inspection Scope (62703)

The inspector reviewed the April 1996 Maintenance Performance Indicator report to determine the results of the licensee's self assessment in the area of maintenance, and the backlog of open safety related work.

b. Observations and Findings

The licensee's current self assessment consists of monitoring performance indicators in six areas. These indicators address nuclear safety, personnel safety, maintenance backlog, work force productivity, training and cost performance.

The work code 1 work authorizations (WAs) consist of primarily non-outage related corrective maintenance on equipment that could affect plant reliability, power generation or safety. Historically, approximately 600 to 650 work code 1 WAs are open at one time, about half of which are safety related. The April 1996 status summary report indicated out of 114 priority 1 and 2 (the highest priority items in work code 1) WAs, 24 were open more than one week. The licensee stated that 30 (i.e., six for each of the five groups in maintenance) has been used as the monthly goal. The licensee plans to revise this goal to 20 for the entire maintenance organization (over a period of one month) and further enhance the timeliness.

The inspector, on a sample basis, reviewed a May 7, 1996, list of priority 1 and 2 open code 1 WAs. The inspector noted that WA S66436 was initiated to correct a loose cable harness connection and missing indicator scale on the reactor vessel fuel zone range level recorder. The WA was opened on April 16, 1996, and work was completed on May 9, 1996. The inspector considered a three week repair time to be too long, as this instrument is needed by the operators under certain post accident conditions for reactor vessel level monitoring. However, the inspector noted that the licensee did not consider this instrument as a post accident monitoring instrument, and hence, did not treat it with additional priority. See Section O2.1 for further discussion.

To improve self assessment and determine the effectiveness of the maintenance program, in March 1995, the licensee developed and issued maintenance standards. These standards are to be utilized in every day work, and in assessing performance. However, full implementation of these standards has not yet been realized. The effort was relaunched in

1996 by forming a group that represented the end users (the maintenance craft personnel). Added emphasis was provided to obtain user buy-in. The standards are being developed in four key areas involving work preparation, physical work, policies and programs, and human performance. Utilization of these standards would be through the use of four checklists that addressed necessary elements of the standards. The licensee expects to implement these check-lists soon.

c. Conclusion

The inspector concluded that the maintenance performance indicators provided an overall assessment of the effectiveness of the maintenance activities. The licensee is revising certain performance goals for further improvement of the timeliness of completion of higher priority work. The licensee's effort to develop systematic standards of performance was a noteworthy effort, and expected to enhance assessment of maintenance.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) URI 50-387,388/93-11-02: Lack of reactor coolant temperature indication during performance of reactor protection system (RPS) surveillance test. In IR 93-11, the inspector found that shutdown cooling was secured with a significant amount of decay heat present and no temperature indication available. Although operators were briefed on the evolution, the inspector concluded that the pre-planning for the surveillance did not adequately consider a number of shutdown risk factors.

In 1993, Revision 6 of SO-158-003, "Semi Annual Division I RPS EPA Functional Test," resolved this issue by requiring available temperature indication, establishing the reactor heatup rate, and calculating of the time to reach 200°F. If heatup to 200°F was calculated to take less than two hours, the surveillance required additional management approval to proceed.

Revision 8 of SO-158-003, dated September 16, 1995, relocated some prerequisites of the surveillance's earlier revisions to Attachments A and B of OP-158-001, "RPS System." The controls implemented via these operating procedure attachments prevent the automatic isolation of the reactor water cleanup (RWCU) system and residual heat removal (RHR) valves that would otherwise isolate shutdown cooling and letdown flow paths, and make reliable RCS temperature indication unavailable. The inspector concluded that the current procedures ensure more reliable decay heat removal, core circulation, vessel letdown, and coolant temperature indication during the RPS surveillance. This item is closed.

III. Engineering

E1 Conduct of Engineering

E1.1 Containment Leakage-(Closed) IFI 50-387; 388/96-01-02

a. Inspection Scope (37551)

The inspector reviewed the licensee's operability/reportability analysis, and action plan for resolving the FSAR discrepancies involving containment leakage and its potential impact on offsite dose calculation.

b. Observations and Findings

The licensee initiated Condition Reports (CRs) to resolve deviations from certain licensing basis assumptions identified during their review of the updated FSAR. These issues could potentially affect offsite dose calculations by impacting (1) the secondary containment bypass leakage assumptions, (2) the contribution to the offsite dose from various systems leakage into the secondary containment, and (3) the 30 day water seal assumed for certain primary containment penetrations. Contribution to post accident environmental release from various system leakage into the secondary containment is filtered through the Standby Gas Treatment System (SGTS), whereas the contribution from the bypass leakage is not.

Bypass Leakage:

FSAR dose analysis assumed a secondary containment bypass leakage of 5 standard cubic feet per hour (scfh) and no leakage through the feedwater penetrations due to an assumed long term water seal. However, a recent review identified that the expected water seal in the feedwater lines, and the HPCI, RCIC, RWCU discharge lines connected to the feedwater lines were not achievable. With no water seal in the lines, the leakage through the feedwater penetrations needed to be added to the total bypass leakage for accident dose calculations. This issue was discussed in detail in inspection report 96-01, and was left open (IFI 50-387; 388/96-01-02) for completion of licensee's review and long term corrective actions (CRs 96-046, 96-310).

The licensee, while reviewing the above issue, identified discrepancies among the FSAR, plant Technical Specifications (TSs), and the leak test program regarding the RHR and core spray keepfill connections. The FSAR and the licensee's leak rate test program reflect the RHR and core spray keepfill connections as secondary containment bypass leakage pathways. However, the TS does not reflect this status. Also, the leak rate test program acceptance criterion of 5 scfh is the same as the offsite dose analysis assumption. Thus adequate margin to account for valve performance degradation or test sensitivities is not included. When the leak rates measured during the last outage for the keep-fill connections are added to the other contributors to the bypass leakage, namely the main steam line drain valves and the feedwater penetrations, the total bypass leakage value is well within the acceptance criterion of 5 scfh. Thus, operability of the secondary containment is not affected (CR 96-356).

System Leakage:

There are two issues involving various system leakage into the secondary containment. The first one deals with the impact of this leakage on offsite dose calculation, and the second one deals with the impact of this leakage on the 30 day water seal assumed in the licensing basis for certain primary containment penetrations.

TS 6.8.4.a requires a program to reduce leakage from systems outside the primary containment that could contain highly radioactive fluid during an accident. The post accident offsite dose calculations in FSAR Section 15.6.5 assumed a 5 gpm leak in the secondary containment from Engineered Safety Feature system pumps, seals and valves. CR 96-504 indicated that this value did not include potential leakage from other sources including the non-seismic control rod drive (CRD) header. The licensee first identified this in 1985 and intended to include this leakage into the design basis. However, the needed followup did not take place.

Primary Containment Penetration Water Seals:

The leakage through the CRD header isolation valves historically exceeded the 5 gpm value, with 41 gpm used as test acceptance criterion, thus potentially placing the plant outside its licensing basis. Licensee's analysis indicated that impact of the increased leakage value on offsite dose calculation was small. As the assumed leakage value is changed from 5 to 50 gpm, the calculated two hour site boundary thyroid dose changes from 125.6 to 136.6 rem. The highest measured CRD leakage never exceeded 12.8 gpm. Hence, the licensee concluded the impact of this increased leakage to the calculated offsite dose would be very small.

TS 3.6.1.2 requires that leakage from all containment isolation valves that are hydrostatically tested be maintained within 3.3 gpm. The valves that are hydrostatically tested are identified in TS Table 3.6.3-1 by note (b), and in FSAR Table 6.2-22 by notes 14 and 26. The plant licensing basis (FSAR Section 6.2.6.3) includes an exemption from pneumatic Type C testing for penetrations that are sealed by the suppression pool (SP) for 30 days. Valves on lines connected to the reactor pressure vessel are included in these Tables as they represent a water loss from the primary containment that would affect SP water level. The Table does not include the CRD header valves. The licensee determined the 3.3 gpm test acceptance criterion was not consistent with the licensing basis, as with a 3.3 gpm leak the HPCI and RCIC turbine exhaust sparger would become uncovered in less than 30 days. Also when leakage from CRD headers are considered, this time is further shortened (CR 96-522).

The inspector noted that in addition to the above FSAR and TS references, the NRC Safety Evaluation Report (SER) in section 6.2.6 indicated that the CRD system leakage would be maintained below 3 gpm by daily inspection. The SER also indicated that leakage monitoring of the insert and withdraw lines is provided by the Type A leak test as the reactor vessel and the non-seismic portion of the CRD system are vented during the test. The licensee is currently reviewing the basis for the SER statements.

The licensee justified continued plant operation based on the latest primary containment leak rate test results that are below 5 gpm for both units including CRD header leakage. Hence, the plant is currently meeting the FSAR licensing basis of 5 gpm. Also the licensee believes that based on their engineering judgement the non-seismic CRD lines will not rupture, and with the seismic island check valves the CRD lines will maintain a 30 day water seal, thus eliminating a CRD header leak.

The licensee's operability analysis also indicated that the current values of total fluid leakage from the primary to secondary containment, considering the CRD header leakage, are 3.39 gpm and 4.59 gpm for Units 1 and 2, respectively. This will maintain a water seal for various lines between 23 and 29 days for Unit 1, and between 17 and 21 days for Unit 2, less than the licensing basis assumption of 30 days. The licensee contends that adequate time for operator action is available to supplement the water seal beyond 17 days.

Summary:

The licensee has developed action items to identify applicable regulatory requirements and licensing basis commitments; and to perform an engineering study to evaluate 1) compliance with regulatory requirements and commitments and 2) the impact on post accident dose calculations. Corrective actions will then be developed as appropriate. The leak rate test criterion for CRD header valves has been revised to 5 gpm to keep the leakage low. This value will be finalized once licensee's review is completed. The licensee does not consider additional reporting to be necessary before completion of this review. The licensee expects to issue a final action plan in September 1996.

c. <u>Conclusions</u>

The licensee's safety assessment, and the operability and reportability determinations completed to date were acceptable. A four hour notification was previously made to the NRC regarding the feedwater seal that was not achievable. This issue will remain open as an unresolved item (URI 50-387; 50-38896-06-01) pending completion of the licensee's action plan and NRC followup review. IFI 96-01-02 is closed.

E2 Engineering Support of Facilities and Equipment

E2.1 Main Turbine Bypass Valve Operability

a. Inspection Scope (37551)

On May 25, 1996, during the Unit 2 weekly turbine bypass valve test (SO-282-001), a plant control operator (PCO) observed that the #1 bypass valve motion was not smooth and that he was unable to confirm the fast acting solenoid had operated properly. The inspector reviewed applicable Technical Specifications (TS) and Bases to assess whether the licensee's determination of operability had adequately addressed the potential safety impact.

b. Observations and Findings

The five main steam turbine bypass valves (BPVs) are normally modulated by servo valves which port fluid above or below a hydraulic ram connected to the valve's stem. Each BPV also has a fast acting solenoid (FAS) valve attached to its hydraulic ram that provides a faster BPV response for mitigation of pressure transients.

Condition Report 96-612 documented the PCO's observation, and its operability determination explained that the TS 3.7.8 surveillance requirement to complete a full stroke of the valve every seven days had been met. The operability determination also stated, "Per conversation with System Engineering, Turbine Bypass Valve #1 is operable." A work authorization was written to investigate the unexpected indications observed by the PCO.

On May 28, 1996, the inspector received a copy of CR 96-612 describing this occurrence and discussed the operability determination with personnel in Operations, Reactor Engineering, and Systems Engineering. The inspector highlighted that TS Bases 3/4.7.8 requires that operability of the main turbine bypass system be consistent with the assumptions of the feedwater controller failure analysis in the cycle specific transient analysis. Based on review of the CR operability determination and discussion with licensee personnel, the inspector established that the licensee had not evaluated whether the operation of the turbine bypass system, without the #1 BPV fast acting solenoid, would be consistent with the assumptions of the feedwater transient analysis.

In response to the inspector's questions, Reactor Engineering representatives subsequently determined that the referenced feedwater transient analysis assumed that all five valves open to 80% within 0.30 seconds and fully open in 0.35 seconds. These response times correspond to the design values for the FAS operation of the BPVs.

TS 3.7.8 requires the main turbine bypass system to be operable in Condition 1 and provides three alternatives if it becomes inoperable: 1) restore it within two hours, 2) evaluate MCPR as greater than or equal to the applicable MCPR limit without the bypass system within one hour, or 3) take the actions required by TS 3.2.3. TS 3.2.3 requires the licensee to initiate corrective actions within 15 minutes and restore MCPR within two hours, or reduce thermal power to less than 25% of rated within the next four hours.

Because the licensee was unable to confirm the fast acting solenoid had operated, the inspector questioned whether the bypass system was operable and if the more restrictive MCPR limit was applicable.

On May 29, 1996, the #1 BPV was tested with additional instrumentation to evaluate whether an actual problem existed. The test data clearly showed proper operation of the #1 bypass valve. The inspector noted that a trace of valve position versus time showed a smooth stroke of the valve to 90% and the expected FAS operation for the last 10% of travel. The PCO reported a similar response was indicated on the main control board.

c. Conclusion

Assessment by Nuclear System Engineering for the turbine bypass valve operability determination did not identify the potential consequences of an inoperable fast acting solenoid on bypass system operability or the feedwater transient analysis. With the bypass system inoperable, a more restrictive MCPR limit would have been required. Although the additional testing four days later revealed acceptable valve performance, the inspector considered the timeliness of the licensee's response inadequate when compared with the two hour allowed action time for implementation of a more restrictive MCPR limit.

E7 Quality Assurance in Engineering Activities

E7.1 (Closed) Part 21-Rosemount Transmitter Hydrogen Permeation Failure

a. Inspection Scope (92903)

The inspector reviewed the licensee's response to a 10 CFR Part 21 notification issued by Rosemount involving certain transmitter failure due to hydrogen permeation.

b. Observations and Findings

NRC Information Notice 95-20, Failures in Rosemount Pressure Transmitters Due to Hydrogen Permeation into the Sensor Cell, discussed a Part 21 notification from Rosemount that stated certain Model 1152, 1153, and 1154 transmitters or sensor module spare part kits could be susceptible to failure.

Rosemount informed the licensee and NRC that the cause of the transmitter failures was hydrogen permeation of the isolating diaphragms. Improperly fabricated sensing modules that contained Monal diaphragms, as opposed to 316 stainless steel diaphragms, are highly susceptible to hydrogen permeation from the reactor coolant system that appear to lead to the failures.

The Part 21 notification identified two production lots of certain sensor modules in Model 1152, 1153, and 1154 transmitters that were manufactured using Monal Alloy 400 isolating diaphragm material. These were shipped to the customers beginning September 1989, and totaled about 200 in number. The Part 21 report also identified that certain 1152 transmitters with option code "T1815" contained Monal 400. Model 1154 transmitters are not used at Susquehanna.

Based on the information from Rosemount, only one affected sensor module spare part kit was shipped to SSES. A review of the warehouse inventory records indicated that this model 1152 sensor module had been removed from "available for use" inventory on December 21, 1994. The licensee removed it from the warehouse on March 27, 1995, and tagged it to prevent its use in the plant. The licensee is making arrangements with Rosemount for its repair or disposal.

The licensee indicated that Rosemount transmitters are directly purchased from Rosemount. This minimized the possibility of vendor's purchase order search not identifying the affected units shipped to SSES. The licensee verified the list of 1152 transmitters installed in the plant to ensure that none of them contained the option code T1815. In addition, the licensee obtained the list of 200 affected transmitters generated by the vendor and verified their data base to ensure that none of them were installed or stocked at SSES.

c. <u>Conclusions</u>

The inspector concluded that the licensee's review of the subject Part 21 notification and corrective actions were adequate and involved sufficient verification to ensure the affected transmitters will not be used at Susquehanna.

E8 Miscellaneous Engineering Issues

E8.1 <u>Licensee Event Reports (90712)</u>

The inspector performed an in-office review of the following licensee event report (LER) and found it acceptable for closure. The LER adequately addressed the issue, the associated causes and corrective actions in place to correct the problem and prevent recurrence.

<u>(Closed) LER 50-387/96-02-00:</u> A post-accident water seal, as described in the FSAR, is not achievable for a postulated LOCA/LOOP DBA. A detailed discussion of the identified condition, licensee's review for reportability and operability, and needed corrective actions is provided

in Section E1.1 of this report and in inspection report 96-01. This issue is being tracked under an unresolved item. The licensee committed to issue a supplement to this LER by October 1996 after completion of their review.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Access Control

a. Inspection Scope (71750)

The inspector reviewed the recent changes made by the licensee in control of access to and egress from the radiologically controlled areas (RCA) of the plant, and monitoring of hand held/personal items to minimize the potential for inadvertent release of contaminated items.

b. Observations and Findings

To improve control over release of tools and materials from the RCA, the Health Physics (HP) control point was moved from the Unit 1 side to the Unit 2 side of the turbine building. As of April 27, 1996, only entry into the RCA was allowed through the Unit 1 side. Posting and a rope barricade were installed at the Unit 1 control point to prevent exit. However, on April 30, 1996, it was reported to the licensee that three workers exited through the Unit 1 side without being monitored for contamination.

The licensee's investigation could not confirm the report. As corrective actions, the licensee closed the Unit 1 control point entirely, hung clearer posting, installed ropes completely barricading the exit, installed surveillance video cameras to monitor various access/egress points, and provided HP coverage and key card control for the alternate exit point through the control structure.

Tool monitors have been installed at the egress points, and workers were trained on proper use of the monitor. A list of personal items that must go through the tool monitors is posted at egress points.

c. Conclusion

The inspector concluded the licensee's actions to improve access/egress control and monitoring of personal items removed from the radiologically controlled areas properly addressed the concerns.

R1.2 External Exposure Controls

a. Inspection Scope (83750)

During NRC Inspection Nos. 50-387/96-04 & 50-388/96-04, inspectors reviewed licensee practices for posting and controlling access to high radiation areas. One condition report (CR 96-144) documented the identification of an un-barricaded high radiation area (see section R1.1.b of the subject report). Additional review of this condition report was performed during the current inspection, and information was gathered by discussions with licensee staff.

b. Observations and Findings

On February 8, 1996, an un-barricaded high radiation area was found in the radwaste building evaporator concentrate sample tank room, 696' elevation, at the top of a scaffold. Dose rates of 1000 mR/h contact and 220 mR/h at 30 centimeters were found. Upon identification, the licensee immediately established a high radiation area access control boundary, and posted the area as a high radiation area. In addition, the licensee performed an investigation and concluded that no unplanned exposures resulted from the failure to barricade this high radiation area. During interviews with licensee staff, the inspectors were informed that this un-barricaded high radiation area was found as a result of a corrective action to perform walkdowns to evaluate access controls for high radiation areas, in response to condition report number CR 96-119, "Unposted High Radiation Area Found in the Decon Building on 818' Foot Elevation."

The licensee determined that the root cause was inadequate human performance in that the staff failed to implement procedural requirements identified in NDAP-00-0626, "Radiological Controlled Area Access and Radiation Work Permit (RWP) System," Rev. 4, to post and barricade the access to the high radiation area. The inspectors noted that this procedure is one of the methods the licensee uses to implement Technical Specification 6.12.1 which states "...each high radiation area in which the intensity of radiation is greater than 100 mrem/h but less than 1000 mrem/h shall be barricaded and conspicuously posted as a high radiation area...".

c. Conclusion

Based on this review, the inspectors concluded that the failure to barricade access to the high radiation area was a violation of Technical Specifications 6.12.1. However, since this violation was identified by licensee staff, and appropriate and timely corrective actions were implemented, this licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on June 28, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

X2 Pre-Decisional Enforcement Conference Summary

On May 7, 1996, a pre-decisional enforcement conference was held at NRC Region I office to discuss potential enforcement issues identified in inspection report 50-387/388/96-03. The issues concerned the manner in which long standing design deficiencies were addressed relative to the plant licensing basis and 10 CFR 50.59. Slides used in the licensee's presentation at the conference are included as Attachment 1 to this report.

NRC conclusions regarding enforcement actions were transmitted by a letter dated June 10, 1996.

X3 Management Meeting Summary

PP&L management met with NRC Region I management on May 28, 1996, to discuss the issues and changes facing the Company. Participants from NRC Region I included Mr. Thomas T. Martin, Regional Administrator, and Ms. Susan F. Shankman, Acting Deputy Division Director, Division of Reactor Projects. Mr. Robert G. Byram, Senior Vice President - Nuclear, was the sole PP&L participant. A copy of Mr. Byram's slide presentation is included as Attachment 2.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

G. Kuczynski, Plant Manager
M. Friedlander, Maintenance Manager
K. Chambliss, Operations Manager
G. Maertz, Nuclear System Engineer
J. Fritzen, Radiation Protection Manager

NRC

C. Poslusny, NRR Project Manager

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 62703:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 83750:	Occupational Exposure
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 90712:	In-office Review of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92902:	Followup - Engineering
IP 92903:	Followup - Maintenance

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-387;388/96-06-01	URI	Feedwater LOOP Seal

Closed

50-387/E94-22-01013:	VIO	Failure to Follow Procedures, Refueling AIT
50-387;388/93-11-02:	URI	Unavailability of Temp Indication During Cold Shutdown
50-387;388/96-01-02	IFI	Feedwater LOOP Seal
95-009 Part 21		Rosemount Transmitter Hydrogen Permeation Failure
50-387/96-02-00:	LER	Post-Accident Water Seal not Achievable for LOCA/LOOP DBA

LIST OF ACRONYMS USED

BPV	Bypass Valves
CAT	Corrective Action Team
CFR	Code of Federal Regulations
CR	Condition Report
CRD	Control Rod Drive
DBA	Design Basis Accident
ESF	Engineered Safety Feature
FSAR	Final Safety Analysis Report
gpm	gallons per minute
HPCI	High Pressure Coolant Injection
IFI	Inspection Follow-Up Item
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
MCPR	Minimum Critical Power Ratio
NCR	Non-Conformance Report
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
PCO	Plant Control Operator
PORC	Plant Operations Review Committee
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RPS	Reactor Protection System
RP&C	Radiological Protection and Chemistry
RPV	Reactor Pressure Vessel
RWCU	Reactor Water Cleanup
SGTS	Standby Gas Treatment System
SSES	Susquehanna Steam Electric Station
SI	International System of Units
SP	Suppression Pool
TS	Technical Specification

PREDECISIONAL ENFORCEMENT CONFERENCE ON NRC INSPECTION REPORT 50-387/388/96-03

PP&L PRESENTATION TO THE USNRC

USNRC REGION I OFFICES
KING OF PRUSSIA, PA.

MAY 7, 1996

AGENDA

- **INTRODUCTION AND MANAGEMENT PERSPECTIVE**............................G. T. JONES
  VP - NUCLEAR ENGINEERING
- **ISSUES**
  - Seismic Monitors..M. W. SIMPSON
    MGR - NUCLEAR TECHNOLOGY
  - HPCI..M. W. SIMPSON
  - SGTS..M. W. SIMPSON
  - RWCU..D. F. ROTH
    SUPV - SYST. ENGRG. /NSSS
- **ASSESSMENT**..W. E. BURCHILL
  MGR - NUCLEAR ASSESSMENT
- **SUMMARY**..G. T. JONES

PP&L MANAGEMENT PERSPECTIVE

- *PP&L has a Strong Record Regarding the Identification and Resolution of Issues Related to the Design and Operation of Susquehanna. Our Standards Include:*
  - Questioning Attitude
  - Priority Based on Safety Significance
  - High Quality Technical Work
  - Management Involvement

PP&L MANAGEMENT PERSPECTIVE

- *Key Concerns Expressed in Inspection Report*
  - "Insufficient attention to the plant licensing basis in operability assessments, and
  - Failure to identify and correct design deficiencies in a timely manner"

APPROACH

Review Each Issue	Review Processes	Nuclear Assessment
Team	Open Items	Management Involvement
Current Status	Training	Regulatory Guidance
Details	Bypasses	Timeliness
	Management Involvement	

SPEAKER'S NOTES

PP&L MANAGEMENT PERSPECTIVE

- *Design Issues by Nature Often Require More Research and Greater Use of Documented Judgment.*
  - **Seismic Monitors:** Interpreting Impact of Location Description on Operability
  - **HPCI:** Evolution of Knowledge on Thermally Induced Pressure Locking Phenomenon
  - **SGTS:** Failure Modes and Effects Analysis Licensing Basis vs. Physical Plant Impacts
  - **RWCU:** Interpreting Intent of Competing Licensing Basis Requirements

PP&L MANAGEMENT PERSPECTIVE

- The Individual Issues Were All Self-Identified.
- The Safety Significance of Each Issue Was Low.
- Priority was Consistently Based on Safety Significance.
- Our Corrective Action Process is Effective.

PP&L MANAGEMENT PERSPECTIVE

- Timeliness Within Our Process Has Improved Overall; Some of the Individual Issues Show Opportunity for Improvement
- Enhancements, Including Training, Are Underway:
  - Stronger Documentation of Reviews
  - Better Use of the Licensing Basis in the Corrective Action Process

PP&L RESPONSE TO NRC INSPECTION REPORT Nos. 50-387/388/96-03

APPARENT VIOLATION ON SEISMIC MONITORING INSTRUMENT LOCATIONS

HPCI INJECTION VALVE

- *PP&L Perspective - EEI 96-03-05*
  - Damaged Pressure Seal Found 11/95
  - Damage Evaluation
    - » Likely Caused by Overpressurization During 5/92 Start-Up
    - » Self-Alleviated
    - » Bounding Calculation Determined Maximum Period of Inoperability During a Startup to Be 8 Days

HPCI INJECTION VALVE

- *Conclusions- EEI 96-03-05*
  - Valve Assumed Inoperable for a Limited Period During Start-Up
  - Overpressurization Self-Alleviated
  - Damage Could Not Reasonably Have Been Avoided Based on Industry Knowledge in 1992

SEISMIC INSTRUMENTS

- *NRC Inspection Report: EEI 96-03-07*
  - "...the licensee had not submitted a special report to the NRC regarding the mislocated, seismic-monitoring instruments."
  - "...the licensee had not performed an analyses per 10 CFR 50.59 to justify leaving the seismic instrument located on the bioshield wall."

SEISMIC INSTRUMENTS

- *PP&L Perspective*
  - Three Instruments are Involved
  - Two (VT15701 & VT25701) Will Be Relocated From the Reactor Building Basemat to the Containment Foundation
  - In the Interim, These Instruments are Operable

SEISMIC INSTRUMENTS

- *PP&L Perspective*
  - Operability of VT15701/25701
    - » Specified Functions are Met :
      - Inform Operator of Earthquake
      - Provide Seismic Readings for Comparison with the Operating Basis Earthquake to Support Shutdown Decision
      - Provide Basis for Evaluating Equipment
    - » Current Location Judged to Provide Conservative Readings

SEISMIC INSTRUMENTS

- *PP&L Perspective*
  - The Third Monitor (VT15702) Is Correctly Located on the Unit 1 Reactor Shield
  - The Location Descriptions in the FSAR, Tech Specs and the Applicable Regulatory Guide and ANSI Standard are Consistent
  - No Change is Planned for This Instrument or the Licensing Basis Documents

SEISMIC INSTRUMENTS

- *Conclusion*
  - This Deficiency Was Self-Identified
  - It Was Properly Dispositioned Per Our Procedures, and Consistent With NRC Generic Letter 91-18 Guidance
  - Safety Significance Is Low
  - All Instruments Are Operable, No Special Report is Required
  - The Location of VT15702 is Consistent with Licensing Basis Documents; No 50.59 Evaluation is Required

SEISMIC INSTRUMENTS

- ***Location Descriptions (VT15702)***
  - Reg Guide 1.12 Section C
    - » One Triaxial Response-Spectrum Recorder *"Should Be Provided"* on *"a Selected Location on the Reactor Equipment..."*
  - ANSI N18.5 - 1974 Section 4.1.2
    - » *"Triaxial Peak Accelerograph Shall Be Provided"* on *"Reactor Equipment"*

SEISMIC INSTRUMENTS

- *Location Descriptions (VT15702)*
  - FSAR Section 3.7b.4.1.1/3.7b.4.1.4
    - » *"Unit 1 Nuclear Boiler Equipment"*
  - Tech Specs Tables 3.3.7.2-1/4.3.7.2-1
    - » *"Reactor Equipment, Unit 1"*
  - Tech Spec Bases Section 3.4.3.7.2
    - » *"This Instrumentation Is Consistent With the Recommendations of Regulatory Guide 1.12 'Instrumentation for Earthquakes' April 1974."*

PP&L RESPONSE TO NRC INSPECTION REPORT
Nos. 50-387/388/96-03

APPARENT VIOLATION ON HPCI INJECTION VALVE PRESSURE LOCKING

HPCI INJECTION VALVE

- NRC *Inspection Report*
  - **EEI 96-03-05**: "The inspector concluded that valve F006 had been inoperable (for an indeterminate period of time) due to overpressurization ...... Reactor operation with questionable operability of the HPCI system is an apparent violation of TS 3.5.1.c.2 ......"
  - **EEI 96-03-06**: "The inspector concluded that, since November 1992, PP&L operated Susquehanna Unit 1 at power, based on inadequately justified engineering judgment and without performing analytical calculations to verify the operability (under conditions conducive to TIPL) of .....HV155F006 ....apparent violation of 10 CFR 50, Appendix B, Criterion XVI ...."

HPCI INJECTION VALVE

- *PP&L Perspective - EEI 96-03-06*
  - PP&L's Valve Program Has Aggressively Assessed Industry Information
    - » Generic Letter 89-10
    - » Pressure Locking and Thermal Binding
  - Over 70 Valve Deficiencies Dispositioned
  - Over 40 Valve Modifications Implemented

HPCI INJECTION VALVE

- *PP&L Perspective*
  - In 1992, PP&L Identified Potential Susceptibility of HPCI F006 to TIPL
  - Issue Was Dispositioned Based on Presumed Existence of Air Pocket
  - An EWR (Non-Deficiency) Was Assigned and Work Was Planned

HPCI INJECTION VALVE

- *PP&L Perspective*
  - Higher Priority Valve Work Took Precedence
  - No New Industry Information Altered Basis (Air Pocket) Prior to 1995
  - Work Was Properly Prioritized
    - » Other TIPL Work Was Proceeding

HPCI INJECTION VALVE

- *PP&L Perspective*
  - Generic Letter 95-07 Screening Process Initiated
  - Susceptibility of HPCI F006 (and RCIC F013) Found as a Result of PP&L Analysis
  - Deficiencies Identified and Promptly Corrected
    - » Unit 1--Modifications Complete
    - » Unit 2--Compensatory Actions In Place
      --Modifications Next Outage

HPCI INJECTION VALVE

- *Conclusions- EEI 96-03-06*
  - PP&L Aggressively Pursued Industry Information and Evolving Knowledge as Part of a Strong Valve Program
  - Based on Available Information, It Was Reasonable to Assume that an Air Pocket Would Mitigate TIPL
  - HPCI Injection Valve Susceptibility Was Identified By PP&L, Not Industry Guidance
  - Prompt Corrective Action Was Taken When Deficiency Was Identified

PP&L RESPONSE TO NRC INSPECTION REPORT
Nos. 50-387/388/96-03

APPARENT VIOLATION ON STANDBY GAS TREATMENT SYSTEM (SGTS) SINGLE FAILURES

SGTS SINGLE FAILURES

- *PP&L Perspective*
  - The FSAR Describes the Failure Modes and Effects Analysis (FMEA) for SGTS
  - Study Performed in 1986 to Improve System Performance Identified Single Failures Potentially Beyond the Licensing Basis
  - Failures Judged to Have Low Safety Significance and Require Further Work

SGTS SINGLE FAILURES

- NRC *Inspection Report:* EEI 96-03-04
  - "The inspector concluded that the SGT and RBR system single failure vulnerabilities constituted a condition adverse to quality that existed since plant construction and remained uncorrected approximately 10 years after initially being identified.... an apparent violation of 10 CFR 50, Appendix B, Criterion XVI ...."

SGTS SINGLE FAILURES

- *PP&L Perspective*
  - Work Entered Into PP&L Engineering Discrepancy Report (EDR) Program in 1990 and Closed in 1992
    - » Determined Not to Be a Deficiency
    - » Transferred to the DBD Program as an Open Item
  - Management Reopened Issue as an EDR in 1993
    - » Screenings Resulted in Assessment of Low Safety Significance
    - » Additional Work Was Performed

SGTS SINGLE FAILURES

- *PP&L Perspective*
  - In July, 1994 Improved Flow Modeling Work Provided New Information Regarding the Consequences of the Postulated Single Failures
  - Failures Were Conservatively Reported on September 12, 1994

SGTS SINGLE FAILURES

- *PP&L Perspective*
  - Resolution of the LER Proceeded in Accordance With Our Procedures
  - SGTS is Operable Based on Meeting its FSAR Safety Functions
  - 1/95: Recirculation Discharge Damper Failure Dispositioned as Non-Credible
  - 3/96: Outside Air Damper Failure Dispositioned by Modification

PP&L RESPONSE TO NRC INSPECTION REPORT
Nos. 50-387/388/96-03

APPARENT VIOLATION ON RWCU ISOLATION SETPOINTS

SGTS SINGLE FAILURES

- *Lessons Learned*
  - Management Should Have Separated Issues of Unresolved Design and Licensing Basis From the Need for Timely LER Disposition Earlier
  - Guidance on Single Failure Methodology for Engineers Needs to Be Resolved
  - Communications with the NRC on LER Status Should Have Been Better

SGTS SINGLE FAILURES

- *Conclusions*
  - Self-Identified Based on Questioning Attitude
  - Low Safety Significance
  - When New Information on Potential Consequences Was Developed, the Issue Was Dispositioned as a Deficiency
  - Timeliness of Dispositioning the Outside Air Damper Deficiency Was Complicated by Selection of the Solution

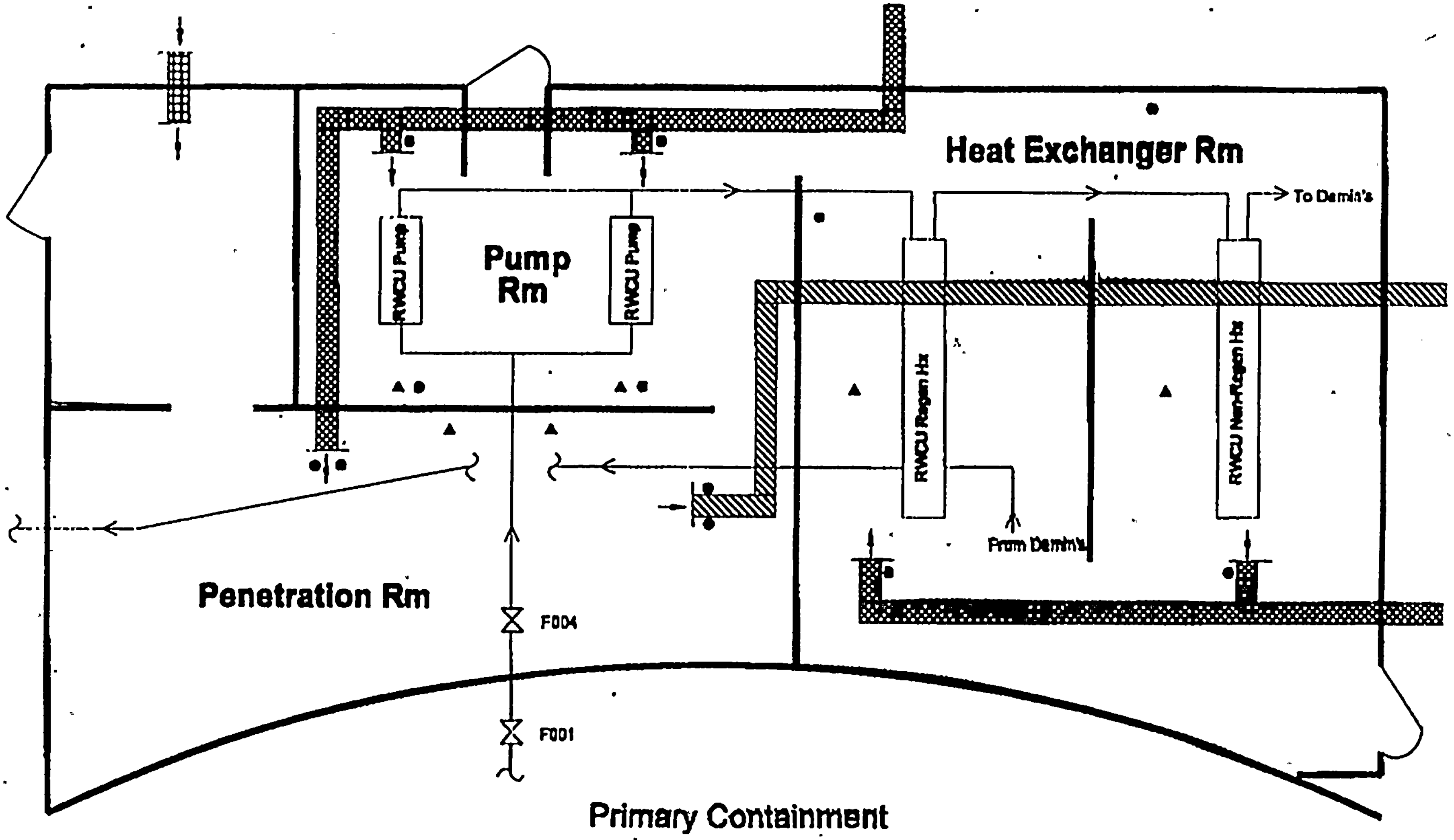
SGTS SINGLE FAILURES

- *PP&L Perspective*
  - The Outside Air Damper Resolution Options Were Identified
  - Decision Was Made to Reevaluate FMEA, as Well as Unresolved Licensing Basis Issues
  - Management Provided Direction to Close the LER
    - » Time Delay Relay Modification

RWCU SYSTEM ISOLATION SETPOINTS

- *NRC Inspection Report:* **EEI 96-03-01**
  - "...on several occasions since 1988, the licensee did not properly consider the SSES licensing basis either in its assessments of system operability or in implementing compensating measures and corrective actions."
  - "...the FSAR was not updated to reflect changes in the isolation system design basis as required by 10 CFR 50.71(e) (4)."

RWCU Area Steam Leak Detection
Room Temperature Instrumentation



Exhaust Air Duct

Supply Air Duct

Transfer Air Duct

▲ Ambient Temperature Element (6 Channels Total) *

● Differential Temperature Element (6 Channels Total) *

* Any one channel will isolate RWCU

RWCU SYSTEM ISOLATION SETPOINTS

- *System Design*
  - Significant Redundancy Exists
  - Delta-T Concept Has Weaknesses
  - Penetration Room Configuration Complicated Setpoint Calculation

RWCU SYSTEM ISOLATION SETPOINTS

- *Outline*
  - System Design
  - Operability
  - Safety Significance
  - FSAR Update
  - Corrective Action

SPEAKER NOTES

RWCU SYSTEM ISOLATION SETPOINTS

- *Operability*
  - Specified Functions:
    - » Avoid Spurious Isolations
    - » Isolate Pipe Leak Before Break
  - EDR Contains Reference to Detection of 30 - 60 Gpm (U1) and 200 Gpm (U2) Leaks
  - NRC SER Contains Reference to Detection of 25 Gpm Leak

RWCU SYSTEM ISOLATION SETPOINTS

- *Operability*
  - Calculational Basis For Calculated Values Understood to Be Very Conservative
  - 25 Gpm Not Considered an Absolute Indication of Operability
  - Documentation Weak
  - Tie to Critical Crack Size Missed
  - Unit 2 Channels Were Inoperable Between April 1993 and June 1995

RWCU SYSTEM ISOLATION SETPOINTS

- *Operability*:
  - NRC Staff Findings:
    - » "..the leakage detection system initiate system isolation when the area temperature conditions exceed the threshold for spurious isolation..."
    - » "The isolation leakage rate under the most conservative initial conditions should normally be less than 25 gpm."

RWCU SYSTEM ISOLATION SETPOINTS

- *Safety Significance*
  - Two Delta-T Channels Affected Per Unit
    - » Channels Were Capable of Isolation
  - Ten Temperature Channels Per Unit Not Affected
  - Flow Channels Not Affected
  - Minimal Safety Significance

RWCU SYSTEM ISOLATION SETPOINTS

- *FSAR Update*
  - Setpoint Change Program Requires Review of FSAR
  - FSAR Change Packages Were Prepared, but Reviews Became Protracted
    - » EDR
    - » Steam Leak Detection DBD
  - FSAR Has Been Updated

RWCU SYSTEM ISOLATION SETPOINTS

- *Corrective Action*
  - FSAR Update — Complete
  - Setpoint Calculation — Complete
  - Unit 2 LER Submittal — 5/31/96
  - Tech Spec Change — 6/10/96

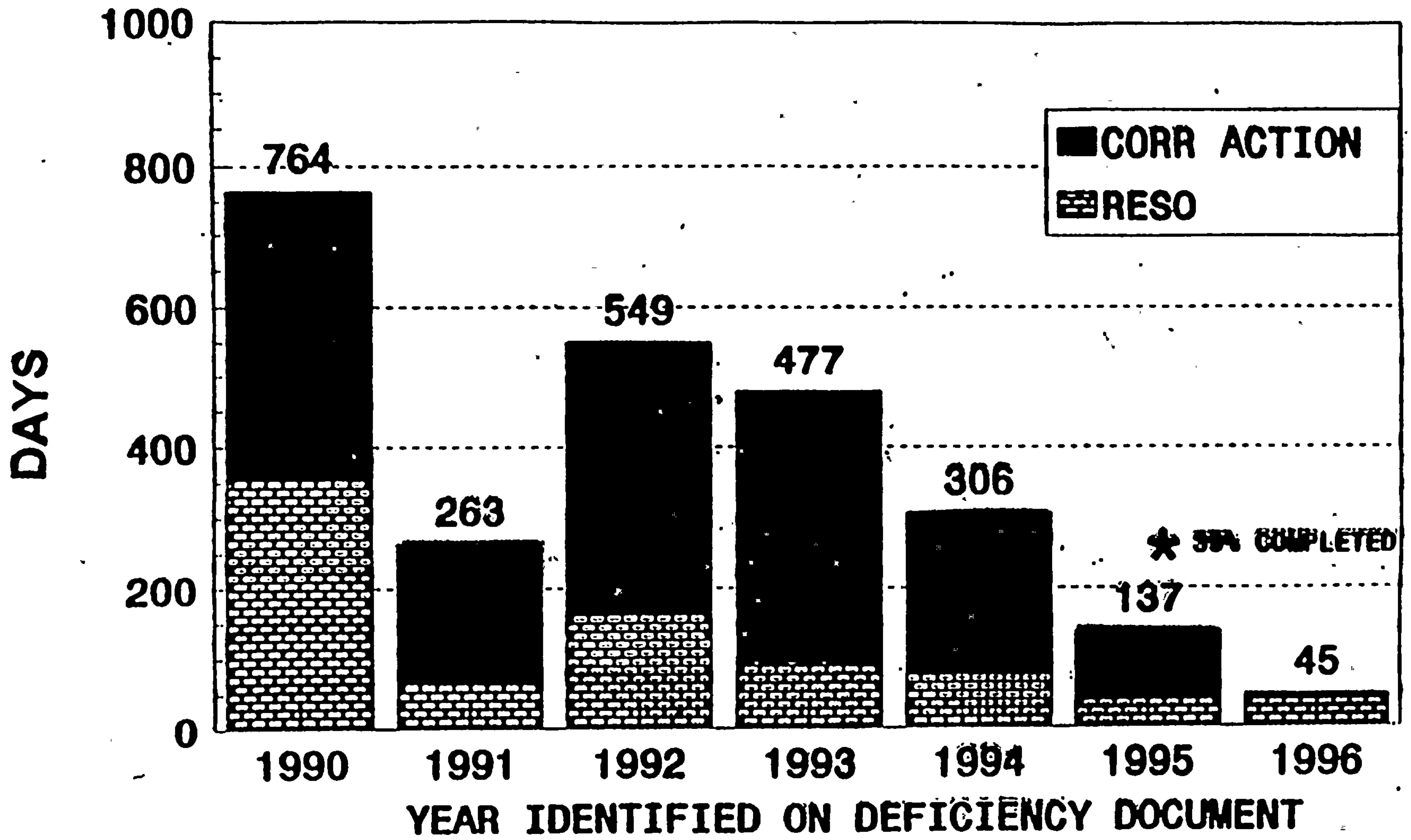
ASSESSMENT

- *Assessment Objectives*
  - Evaluate Management Involvement
  - Evaluate Consistency with Regulatory Guidance
    - » Evaluate Licensing Basis Maintenance
  - Evaluate Timeliness
    - » Define Corrective Actions (Resolution)
    - » Execute Corrective Actions (Closure)

ASSESSMENT

- ***Management Involvement In PP&L's Engineering Deficiency Resolution Process***
  - **1989:** Engineering Deficiency Work Performed Under EWRs
  - **1990:** Management Commissioned EDR Program
  - **1991:** EDMG Established, Policies Implemented:
    - » Priority Based on Safety Significance
    - » Refueling Cycle Lifetime for Deficiencies

TIMELINESS OF RESOLVING & CORRECTING ENGINEERING DEFICIENCIES



CORRECTIVE ACTION ... Average number of calendar days from approval of the Resolution until Closure of the Deficiency, which is after all Corrective Actions are completed.

RESOLUTION ... Average number of calendar days from identification of the Deficiency on an EDR or Condition Report until approval of the Resolution (Cause Determination & Corrective Action Plan).

ASSESSMENT

- *Management Involvement*
  - **1993:** Lessons Learned Reviews
    - » "Validation" Step Eliminated
    - » Hand-offs to Other Programs Eliminated
  - **1994:** Management Chartered Team to Consolidate Deficiency Management Programs
  - **March 6, 1995:** Condition Report Procedure Issued

COMPARISON TO REGULATORY GUIDANCE

Generic Letter 91-18	EDR	CR
Identification	✓	✓
Prompt Follow-up Action	✓	*Improved*
Operability Determination	✓	*Improved*
Reporting	✓	✓
Decision Category	✓	✓
Interim Operation	✓	✓
Deficiency Resolution	✓	*Improved*
Long Term Follow-up	✓	✓

ASSESSMENT

- *CR Process Key Improvements*

Prompt Follow-up Action

- CAT Review (cont'd)
  - » Need for ERT/Root Cause Analysis
  - » Status Resolutions/Approve Extensions

Operability Determination

- Operability Proceduralized
  - » Parallels Generic Letter 91-18 Guidance

Deficiency Resolution

- Improved Timeliness
  - » Resolution Time Reduced From 45 to 30 days

ASSESSMENT

- *CR Process Key Improvements*

  General

  - Single, More User-Friendly Process
    - » Combined EDR, SOOR, NCR, HPES, and QA Findings

  Prompt Follow-up Action

  - Independent 24 hour Investigation
  - Daily Corrective Action Team ("CAT") Management Review
    - » Background, Repeat Event Evalu[illegible]ion
    - » Significance L[illegible]vel, Lin[illegible] Mgmt. Assignments

PROCESS REVIEWS

- *A Number of Sources Were Reviewed to Determine if Potential Generic Process Implications Existed:*
  - Old EDRs *
  - Existing Engineering Training
  - Use of 50.59 in Support of Bypasses
  - Engineering Review Committee Record
  - Susquehanna Review Committee Subcommittee on Safety Evaluations

* *Six of the 14 "Old" EDRs at the Time of the Inspection Have Been Closed.*

SHORT TERM CLOSURE STATUS

- **SGTS**
  - Modification Operational — *Complete*
  - Update LER — 5/20/96
  - Complete FMEA — 7/7/96

- **RWCU**
  - Update EDR Operability — *Complete*
  - Setpoint Change Calculation — *Complete*
  - Update FSAR — *Complete*
  - Submit Unit 2 LER — 5/31/96
  - Submit TS Change — 6/10/96

SHORT TERM CLOSURE STATUS

We are Proceeding with Resolution of the Issues in Accordance with our Process.

- **Seismic Monitor**
  - Relocate Containment Foundation Monitor 8/30/96
- **HPCI**
  - Unit 1 Modification Operational *Complete*
  - Unit 2 Interim Actions in Place *Complete*
  - Unit 2 Modification Operational 3/97 RFO

ASSESSMENT

- ***Assessment Results***
  - PP&L's Corrective Action Process is Focused on Safety and 10CFR50 Appendix B Compliance
    - » Strong Management Involvement
    - » Aggressively Implements NRC GL 91-18
    - » Acceptable and Improving Performance on Timeliness
  - Opportunity For Improvement
    - » Need to Reinforce Consideration of Licensing Basis Documentation

ASSESSMENT

- Histogram

- ***Key Findings***
  - Old Issues Being Worked
  - 50.59's Well Done
    - » Adjustments Made Where Appropriate
  - Strong Management Involvement

SPEAKER'S NOTES

PROCESS ENHANCEMENTS

- ***Lessons Learned from Individual Issues and Process Reviews Identified Several Potential Enhancements :***

  - Revise Condition Report Procedure to Provide Improved Guidance on Use of 10CFR50.59 and Maintenance of Licensing Basis Documentation 6/1/96
    - » Assess Other Processes for Similar Needs 6/1/96

  - Complete Training on Use of Licensing Basis Documentation for Engineering Supervisors 6/15/96
    - » Complete Training for Engineers 9/30/96

PP&L MANAGEMENT PERSPECTIVE

- *PP&L is Reviewing the Unresolved Items to Determine if Our Processes Require Clarification.*
  - Use of 10CFR50.59
  - Single Failure Credibility
  - Use of 10CFR100 in Operability Evaluations

SUMMARY

- The Individual Issues Were All Self-Identified.
- The Safety Significance of Each Issue was Low.
- Priority was Consistently Based on Safety Significance.
- Our Corrective Action Process is Effective.

SUMMARY

- Timeliness Within Our Process Has Improved Overall; Some of the Individual Issues Show Opportunity for Improvement
- Enhancements, Including Training, are Underway:
  - Stronger Documentation
  - Better Use of the Licensing Basis in the Corrective Action Process

ATTACHMENT 2

PP&L/NRC MEETING

MAY 28, 1996

NRC REGION I OFFICES

KING OF PRUSSIA PA

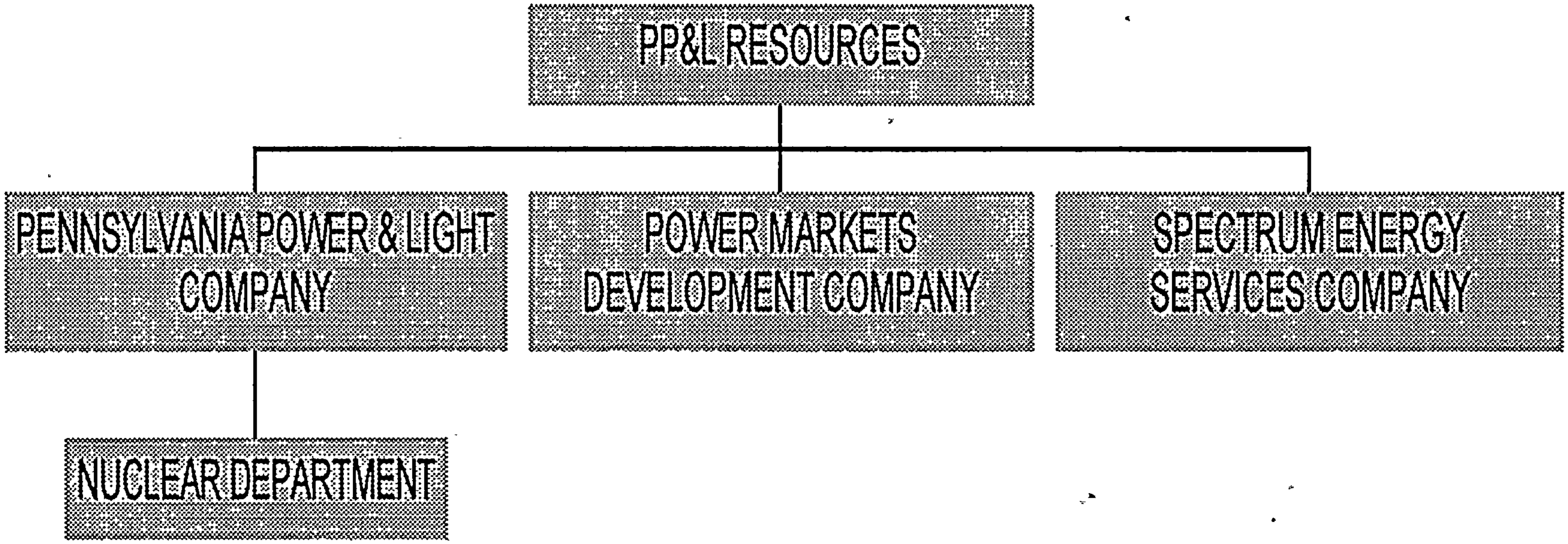
Meeting Objectives

- Update NRC on PP&L Strategic Direction
- Discuss Progress and Challenges
- Obtain Feedback
  - PP&L Performance
  - Regulatory Climate

PP&L Topics

- PP&L Strategic Direction
  - Corporate
  - Nuclear Department
- Issues
  - Engineering Issues
  - Current Licensing Basis
  - Health Physics
  - Security
  - (*Bargaining Unit Negotiations Preparation-backup only*)

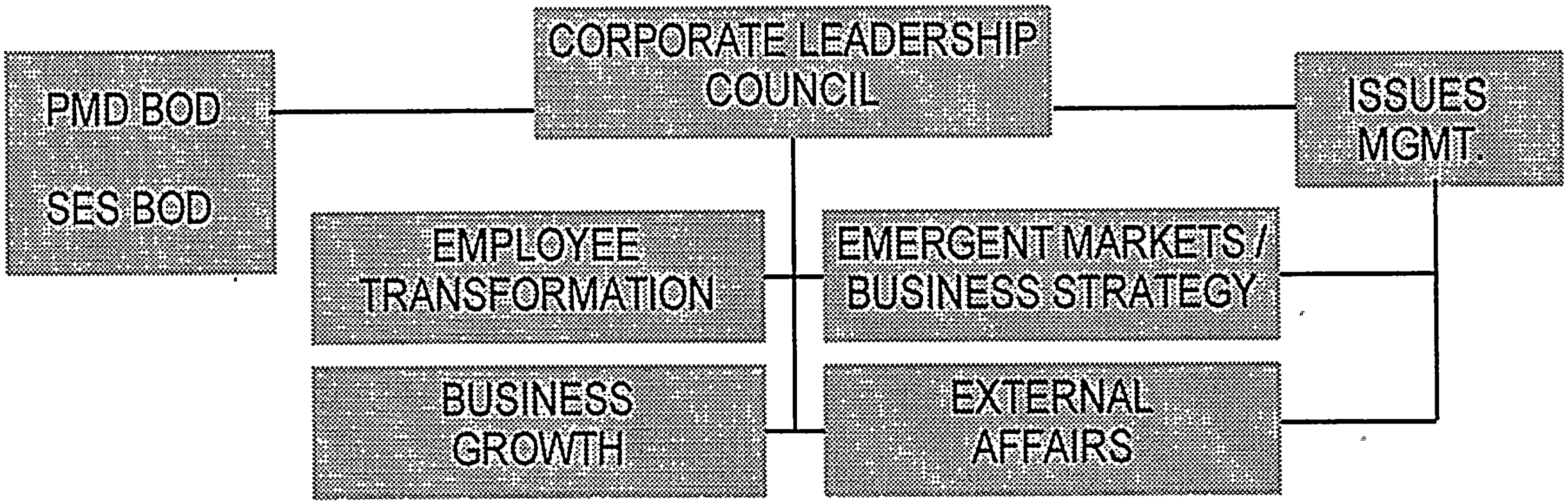
Corporate Structure



PP&L Corporate Direction

- *PP&L Resources is well prepared to build on its strengths and to take advantage of the opportunities presented by a new, more competitive electric utility industry.*
  - Focus on Core Business in Communities We Serve
  - Superior Nuclear Performance
  - Shaping the Future for Competitive Success
  - Electric Energy Market Development

CORPORATE CHANGE MANAGEMENT



Keys to Success

- *Susquehanna has built its reputation on long term, high level performance.*
  - Communication: Open, Honest, Effective
  - Training & Development: Maximizing Potential
  - Assessment: Department & Line Management
  - Teamwork: Reaching Common Goals
  - Industry Involvement: Learning From Others
  - Sr. Mgmt. Involvement: Active Leadership
  - Corporate Commitment: Long Term Vision

Nuclear Dept. Organization

(Effective Date: May 10, 1996)

- Robert G. Byram
  Sr. Vice President - Nuclear
  - George T. Jones
    Vice President - Nuclear Engineering
    - Nuclear Dept. Support
    - Emergency Planning
    - Licensing
    - Work Mgmt. Team
    - Glenn D. Miller
      Manager - Nuclear Engineering
      - Systems Engineering
      - Fuels
      - Modifications
      - Technology
    - George J. Kuczynski
      Plant Manager - Susquehanna
      - Operations
      - Maintenance
      - Outages
      - Plant Services
        - Security
        - Health Physics
        - Procurement
        - Effluents Management
        - Site Support
  - Nuclear Safety Assessment
  - Nuclear Information Services
  - Nuclear Training
  - Nuclear Business Improvement

Nuclear Department Direction

- *Long Term, Safe, Reliable Operation is the Key to Our Business Success in the Transition to a Deregulation.*
  - Maintain Operating Fundamentals
  - Continuously Improve
  - Promote Public Trust & Involvement
  - Self Assess & Maintain External Focus
  - Focus on People & Manage Change

Managing Change

- *Change Requires:*
  - – Vision
  - – Leadership
  - – Strategy Focused
    - Process Driven
  - – Improvement Through People

Nuclear Department Vision

- *Susquehanna Will Become a World Class Performer:*
  - World Class Safety
  - World Class People
  - World Class Business

Leadership

- *Our Vision Requires an Enhanced Ability to Implement and to Balance Our Interpersonal, Technical and Business Skills*
  - Leadership Academy
  - Training the First-Line Supervisor
    - Conflict Resolution
    - Employee Concerns

Nuclear Department Strategic Planning Model

Nuclear Department Strategic Objectives & Initiatives

- Operate SSES Safely
  - Achieve an Event-Free Environment
  - Achieve an Accident-Free Environment
  - Reduce Radiological Exposure Using All Available Methods

Nuclear Department Strategic Objectives & Initiatives

- Improvement Through People
  - Build and Lead a Work Force that is Motivated to Perform at Full Potential and is Continuously Improving
  - Improve Cycle Time, Quality, and Customer Satisfaction of the Department's Processes
  - Assure a Continuing Skilled and Productive Work Force
  - Facilitate Innovation in the Department to Provide a Competitive Advantage

Nuclear Department Strategic Objectives & Initiatives

- Make SSES Economically Self-Sufficient
  - Deliver and Accelerate Activities Which Will Achieve the Targets of Strategy 2000
  - Use Decision Analysis to Optimize Capital and Major O&M Project Investments and Revenue Enhancements
  - Understand and Quantify the Power for Forming Strategic Alliances
  - Support the Corporation in its Public Policy Endeavors to Recover Stranded Investment
  - Achieve Long-Term Station Reliability

Nuclear Department Strategic Objectives & Initiatives

- Continuously Earn the Trust and Confidence of Our Publics
  - Provide an Effective Interface with the Nuclear Regulator
  - Provide an Effective Interface with Our Publics
  - Become Power Systems Support's Supplier of Choice
  - Improve Employee Community Involvement

What's Ahead: 1996

- Major Projects
  - Hydrogen Water Chemistry
  - Condensate Filtration
  - 24 Month Cycles
  - Improved Technical Specifications
  - Licensing Basis Documentation Maintenance
  - Maintenance Rule Implementation
  - Reactor Core Stability
- Other Major Initiatives
  - U1 9th RFIO: 36 Days
  - Employee Concerns Program
  - Leadership Academy
  - Business Planning
  - Process Mapping

What's Ahead: 1997

- Major Projects
  - Hydrogen Water Chemistry
  - Condensate Filtration
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- Other Major Initiatives
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  - Business Planning
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Engineering Issues

- Key NRC Concerns
  - Licensing Basis
  - Timeliness of Corrective Action
- PP&L Perspective
  - Corrective Action Process Effective
  - Enhancements Occurring, With Focus on Attention to Licensing Basis

Current Licensing Basis

- Project Began in February, 1996
- Objectives
  - Characterize Vulnerabilities, Determine Need for Immediate Actions
  - Determine Need for CLB Verification
  - Identify Long Term Process Improvements
  - Disposition NRC Information Notice 96-17
- Three Phases
  - I: Problem Definition *Complete*
  - II: Assessment *Ongoing*
  - III: Verification (contingency)

Current Licensing Basis

- Phase I Key Results
  - Industry
    - Significant Regulatory Concern Exists
    - Sensitivity to CLB Issues Has Increased
  - SSES CLB Strengths
    - Thorough "Post TMI" Licensing Process
    - Substantial Recent CLB Turnover: eg., DBD, PUP, ITS
  - Likely Areas for Improvement
    - Strengthening of Process Controls
    - Training on Better Use of CLB

Security

- *Substantial Corrective Action Progress is Occurring*

– Personnel Actions	complete
– Security Issues Team Progress	ongoing
– First Line Supervisor Training	
• Employee Protection	complete
• Conflict Resolution	complete
• Leadership Academy	ongoing
– Management Communications	
• Lessons Learned	complete
• Discussion Groups	ongoing
– Management Guidance	complete
– Assessment Enhancements	ongoing
– HR&D Support	complete

Health Physics

- Status of Ongoing Activities
  - Technical and Programmatic Issues
  - Employee / Supervisor Issues
  - Causal Factors Analysis
  - Organization Self Assessment
  - Follow-up on ISES Assessment
  - Employee Concerns Program Changes

Bargaining Unit Issues

- Current Labor Agreement Expires 5/18/97.
- Management Plans Have Been Worked Since late 1995.
- All Individuals Licensed on SSES (including inactives) are Attending Current Requal Training.
  - Can Support Three Full Shifts Working Normal 12 Hour Schedule
  - Requalification / Simulator Training Will Occur
  - Physical Exams Scheduled
- Security Staff are Management Employees.

Discussion