

ATTACHEMNT 1

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SALEM STARTUP
AND POWER ASCENSION
UNITS 1 and 2

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Salem Restart Plan

Following the Salem Shutdown, the "SALEM RESTART PLAN" was developed to outline a systematic approach for the Integrated Testing associated with the Salem restart effort. The program was been defined in Procedure SC.TE-TL.ZZ-0001(Q), Startup And Power Ascension Program.

The plan established testing in 4 phases to ensure testing was documented and that the testing was sufficient to validate restart readiness. The focus of the test program was in the area where plant modifications were made. The 4 phases were:

- Phase I - Component Level Testing
- Phase II - System Level Testing
- Phase III - Integrated Testing
- Phase IV - Startup and Power Ascension Testing.

The existing Design Change Process was determined adequate to ensure that testing performed validated the design bases. By using Salem's normal process controls and demonstrating they worked, the overall effort supported the individual Salem Restart Action Plans. The process controls consisted of the present Work Control Process, Design Change Process, Special Tests and Infrequently Performed Evolution Process and the Procedure Development Process. Packaging these processes under the System Readiness Review Program on a system by system bases was the essence of the Startup and Power Ascension Program.

This concept was presented to the Management Review Committee and approved on November 14, 1995. Subsequently, revision zero of the Startup and Power Ascension Program procedure was completed and presented to the Management Review Committee for approval on December 7, 1995.

Hold Points and Criteria for Continuing Restart

Power ascension for both Unit 2 and Unit 1 used "Hold Points" to evaluate the Units readiness to progress with the startup. Established plant performance-hold points were placed prior to a plant Mode change and at specific reactor power levels; 25%, 47% and 90%.

There were two types of Hold Points during Startup and Power Ascension. They are Planned Assessment Hold Points and Plant Performance Hold Points. These hold points were controlled in the "Startup and Power Ascension Sequencing" procedures.

Planned Assessment Hold Points permitted a systematic management review and assessment of plant and personnel performance to ensure that the plant and the organization were ready to proceed with the startup plan. Planned Assessment Hold Points include planned assessments by the line organization and independent assessments by the Quality Assessment Department. These planned assessments were conducted during the ascension to the "Hold Point" and provided input to the department manager's recommendation to the General Manager - Salem Operations to continue with the startup. The assessment criteria were developed from the station self assessment diagnostic performance standards, criteria and attributes.

Plant Performance Hold Points allow time for a deliberate decision to be made by the Shift Plant Manager that the sequence should progress to the next set of activities in the startup. The decision is based on satisfactory plant performance, acceptable test results and effective resolution of open and emergent issues. Plant Performance Hold Points ensure that all information is considered (i.e. material condition, completion of necessary corrective maintenance actions, personnel performance, responsiveness of support activities, etc.) supporting the decision to continue with the startup.

Lesson learned from Unit 2 startup and a management recommendation changed the way hold points were satisfied on Unit 1. Specifically, to proceed past a hold point on Unit 1 required the testing to be completed and reviewed by the Test Review Board (TRB), or required a SORC presentation of startup test results from the TRB and approval of the General Manager Salem Operations. This change was made to increase management oversight in the startup and power ascension process.

Assessments

Assessments were performed to evaluate the plant and the organizations ability to operate Salem in a Safe and Reliable manner. Assessments were performed at designated plant conditions (prior to fuel load, prior to proceeding into Mode 2, at 25%, 47% and 90% reactor power and a final assessment after reaching 100% power). The assessments verified that Salem had met it's expectations of effective implementation of policies and directives, management expectations for high standards of station performance and the planning and control of station activities.

The assessments utilized data obtained from self assessment observations submitted by each organization; Startup Organization, Operations, Maintenance, System Engineering, Radiation Protection and Chemistry. The Observations submitted were forwarded to the Salem Self Assessment Coordinator, who compiled the observations into assessment results. The assessment results were then returned to the submitting organization. Each organization reviewed the results and submitted an affirmation to SORC as to the plant and organizations readiness to continue with the startup. SORC made recommendations to the General Manager-Salem Operations as to the plants readiness to continue with the startup. Based on the recommendation, General Manager-Salem Operations authorized proceeding with the plant startup.

STARTUP SUMMARY

No major test delays were encountered during the Unit 1 startup. This was primarily due to better test planning, better coordination between departments, experience and knowledge gained from the Unit 2 startup and through the lesson learned program instituted as part of the Unit 2 Startup.

Lessons learned included a contingency plan which identified actions should equipment problems arise during the startup, cause & effect evaluations of installation of test equipment, increased awareness of plant conditions required to perform testing and a rewrite of DCP special test procedure (STP) to address testing concerns identified during Unit 2 startup. STP's were rewritten to have a consistent format and to be more specific on what was tested by each STP. For example on Unit 2 the test procedure for the Heater Drain Pumps tested all the pumps using 1 procedure and on Unit 1 six procedures were used to test the heater drain pumps. This resulted in more test activities to accomplish the same task but resulted in less problems during the startup.

Several equipment problems did occur during the testing but did not result in significant startup delay. The first obstacle was performing Component Cooling System (CC) flow balance. System cleanup was required prior to completing the testing which took approximately 10 days. Heater Drain Pump problems and valve problems were encountered during the startup. Testing was delayed for replacement of the 11 Heater Drain Pump and repair of the 12HD9 valve. This work was performed after 100% fuel conditioning was completed. During the 25% turbine runback test at 90% reactor power, rods did not respond as expected. The test was completed satisfactorily but required investigation into rod control system. It was determined that rod control functioned as designed and this was verified on May 13, 1998, during performance of the 40% Turbine Load Reject test. The SGFP trip test was completed on May 14, 1998 which completed the major testing on Unit 1.

STARTUP SUMMARY

Several problems occurred during Unit 2 startup that resulted in testing delays. The major testing delay encountered during the startup was for installation and testing of the Service Water CFCU modification. This resulted in an approximate 4 month delay in the startup.

The delays that occurred in Mode 3 were caused by 22 Reactor Coolant Pump high vibration, leaking BIT isolation valves, and the inability to pressurize the steam system on pump heat. The Mode 2 delay occurred due to problems with the rod position indication system. The Mode 1 delays occurred due to, Flux map problems with the P-250 computer, NI adjustments, Pressurizer level instrumentation deviations and with various problems with the Steam Generator Feed Pumps (SGFP).

After reaching 100% power on Unit 2, Steam Generator water chemistry went out of spec on September 30, 1997 and Reactor Power was reduced to approximately 55%. Seven plugs were repaired in the condenser water boxes and Chemistry was returned to in spec. Reactor Power was returned to 100% on September 30, 1997.

Unit 2 had a manual Reactor Trip from 100% power on October 2, 1997, due to Steam Generator Feed Pump Low Suction Pressure. The cause of the low suction pressure was caused by a fault in test equipment installed on the Digital Feedwater System. In addition, post-trip cooldown of the unit went smoothly, and the unit response proved that repairs and modifications made during the outage were successful. The unit was restarted on October 6, 1997.

UNIT 1 STARTUP

Mode 6

Unit 1 startup was officially entered on November 30, 1997, when core reload commenced on Unit 1. Core loading was completed on December 4.

Twenty-three tests activities were completed while in Mode 6. General Manager, Salem Operations authorization was obtained on December 10, 1998, for Unit 1 to proceed to Mode 5. No unexpected delays in startup and power ascension testing were noted while in Mode 6

Mode 5

Unit 1 entered Mode 5 on December 11, 1997.

Thirty-eight tests activities were completed while in Mode 5. One test (1EE-0117-1, Steam Dumps to Condenser) could not be completed in Mode 5 and testing requirements were moved to Mode 4. The test was field complete but required an engineering evaluation of the acceptance criteria. On January 5, 1998, it was identified that RVLIS data collection had not been performed prior to establishing a pressurizer steam bubble as required by the sequence procedure. An evaluation determined there was no plant impact for the missed data, due to the data collected is not used to generate new curves and is not used for the new EOP setpoints. General Manager, Salem Operations authorization was obtained on February 18, 1998, for Unit 1 to proceed to Mode 4. No unexpected delays in startup and power ascension testing were noted while in Mode 5.

UNIT 2 STARTUP

Mode 6

Unit 2 plant startup was officially entered on December 16, 1996 when core reload commenced on Unit 2. Fuel loading was completed on December 21.

Thirty-eight tests activities were completed in Mode 6. Mode 6 test requirements were completed on December 24, 1996. No unexpected delays in startup and power ascension were noted while in Mode 5.

Mode 5

Unit 2 entered Mode 5 on December 26, 1996.

Forty-seven tests activities were completed while in Mode 5. On February 3, 1997, the Unit startup was essentially halted for implementation of 96-06 modification /integrated testing of Service Water Containment Fan Coil Units (CFCU) and due to problems with Control Area Ventilation. Implementation and testing of 96-06 modification took until June 9, 1997. Mode 5 testing requirements were completed on June 14, 1997, and Management Review Committee (MCR) approval was given to proceed to Mode 4.

UNIT 1 STARTUP

Mode 4

Unit 1 entered Mode 4 on February 18, 1998.

Sixty-one tests activities were completed while in Mode 4. Three test activities could not be completed in Mode 4 and were moved to another Mode. 1EC-3206, STP-001D & E for testing of the BF19 and 40 valves were moved to a Mode 3 test requirement. The valves were being reworked by I&C and the valves are not required operable until Mode 2. 1EE-0117-1, Steam Dump to Condenser testing, was moved to a Mode 2 test requirement waiting resolution of the acceptance criteria from engineering.

General Manager, Salem Operations authorization was obtained on March 14, for Unit 1 to proceed to Mode 3. No unexpected delays in startup and power ascension testing were noted while in Mode 4.

Mode 3

Mode 3 was entered on March 17, 1998.

Forty-two tests activities were completed while in Mode 3. Reactor Coolant Pump high vibrations were encountered while in Mode 3. The pumps were balanced while performing RVLIS testing at 540° F. On March 25, 1998, Operations experienced problems with letdown flow while setting up to perform Pressurizer Level tuning. Tuning was delayed for evaluation of the letdown problem. This did not result in a delay in the startup as Pressurizer level tuning could be performed at higher power levels without impacting the plant. Pressurizer level tuning was not completed in Mode 3 and was moved to Mode 1.

After department affirmations and NRC approval, General Manager, Salem Operations authorization was obtained for Unit 1 to proceed to Mode 2 on April 7, 1998. No unexpected delays in startup and

UNIT 2 STARTUP

Mode 4

Unit 2 entered Mode 4 on June 14, 1997.

Eight tests activities were completed while in Mode 4. While in Mode 4, Steam Generator Feed Pump (SGFP) testing associated with Design Change Package (DCP) 2EC-3306 experienced various problems. SGFP trouble shooting was started and resulted in testing requirements being moved to Mode 2.

Mode 4 testing requirement were completed on July 1, 1997, and Management Review Committee approval was given to proceed to Mode 3.

Mode 3

Mode 3 was entered on July 3, 1997.

Twenty-four tests activities were completed while in Mode 3. Startup Testing delays in Mode 3 were caused primarily due to equipment issues. On July 4, 1997, Pressurizer Safety Relief Valve, 2PR4 was identified as leaking. This resulted in having to reduce primary pressure to approximately 1500 psig, on July 7, 1997, to seat 2PR4. On July 5, 1997, 22 Reactor Coolant Pump (RCP) vibration problems were encountered. This event resulted in testing delays for Reactor Vessel Level Indicating System (RVLIS) and in pressurizing the steam system for trouble shooting per Steam Cycle Monitoring per procedure S2.SE-PR.ZZ-0001. The 22 RCP vibration problem resulted in the pump being removed from service for troubleshooting. On July 8, 1997, during RVLIS testing 21 RCP lift

UNIT 1 STARTUP

power ascension testing were noted while in Mode 3.

Mode 2

Unit 1 entered Mode 2 on April 7, 1998.

Fifteen tests activities were completed while in Mode 2. Reactor power was increased to 3% on April 11, 1998. General Manager, Salem Operations authorization was obtained on April 12, 1998, for Unit 1 to proceed to Mode 1. No unexpected delays in startup and power ascension testing were noted

UNIT 2 STARTUP

pump tripped. This resulted in a delay in RVLIS testing until the 21 RCP lift pump was replaced later the same day. Another problem was not being able to pressurize the secondary. Steam cycle monitoring per S2.SE-PR.ZZ-0001, was performed to identify the leakage path to the main condenser. Various steam paths to the condenser were identified but the secondary could only be pressurized to approximately 740 psig without cooling off the primary. On July 23, 1997, Unit 2 commenced a cooldown to Mode 5 for troubleshooting leaking BIT isolation valves and for trouble shooting steam dumps.

The testing delays while in Mode 3 were with the Steam Generator Feedwater Pump testing, Steam Dump control loop functional testing, Atmospheric Relief Valve (MS10) dynamic testing and with Letdown control loop functional testing. SGFP's experienced problems with the governor and with the ability to latch, which extended some testing for approximately one month. Some of the SGFP testing was originally scheduled to be completed in Mode 4 but was moved to Mode 2. Steam Dump and MS10 testing was delayed due to problems with the test procedure, problems with installation of test equipment and the inability to pressurize the main steam system on pump heat. Letdown temperature and pressure functional testing was required to be repeated due to the acceptance criteria not being satisfied. Mode 3 testing requirement were completed on August 7, 1997.

Mode 2

A delay in the startup was encountered on August 7, 1997 during rod pulls due to deviations in IRPI rod position indications. Trouble shooting of the rod position indication problems and corrective actions were not completed until August 17, 1997. This resulted in a delay in Hot Zero Power testing.

UNIT 1 STARTUP

while in Mode 2.

Mode 1

Unit 1 entered Mode 1 on April 13, 1998. Reactor power was increased to 9% on April 13, 1998 and held at that power until April 17, 1998 when the turbine was synchronized to the grid. Power was then increased to 24%. After department affirmations and NRC approval, General Manager, Salem Operations authorization was obtained allowing reactor power to be increased to the 47% plateau, on April 18, 1998.

A Reactor power of 47% was achieved on April 19, 1998. The 47% fuel conditioning was completed on April 23, 1998. After department affirmations and NRC approval, General Manager, Salem Operations authorization was obtained allowing reactor power to be increased to the 90% plateau, on April 23, 1998. Power was then increased to the 60% on April 23, 1998 for heater drain pump testing and then to 75% plateau on April 23, 1998 for Reactor Engineering testing. On April 29, 1998, a power increase was started to the 90% plateau. The power increase was performed prior to signoff of the Refueling Test Sequence Procedure by Reactor Engineering. A review to determine the impact of performing the steps out of sequence was performed and it was determined that the missed step did not

UNIT 2 STARTUP

Mode 2 was entered on August 17, 1997, and Hot Zero testing was started.

Four tests activities were completed while in Mode 2. On August 18, 1997, 2 rods on D Control Bank drifted >12 steps out of alignment. Unit 2 entered Mode 3 on August 19, 1997, as required by Technical Specifications due to the rod deviation problem. Rod deviation corrective actions were completed and Unit 2 entered Mode 2 August 22, 1997. Hot Zero Power Testing was completed on August 24, 1997. Unit 2 increased Reactor Power to 2% on August 24, 1997.

Mode 1

Mode 1 was entered on August 26, 1997.

Twenty-two tests activities were completed while in Mode 1. ADFCS testing experienced testing problems at the 7 - 10% Reactor Power level and could not be performed due to low feedwater flow conditions at that power level. The ADFCS testing was rescheduled. Unit 2 synchronized to the grid on August 30, 1997, where power was held at 20 % for Digital Feedwater testing. Power was increased to the 25% on August 30, 1997. Delays at the 25% Hold Point were caused by Gland Seal Steam Testing and problems with the P-250 computer. The Gland Seal Steam Test could not be completed due to inoperable equipment in the GS system and the test was rescheduled to be completed with the Unit at 100% Reactor Power. The problem with the P-250 computer resulted in a 12 hour delay in plant startup due to problems with obtaining data for the flux map, on September 1, 1997. This problem was resolved, which completed the required testing necessary for exceeding 25 % power. The NRC granted permission to increase power to the next hold point of 47 % on September 1,

UNIT 1 STARTUP

result in any safety issues. The step intent had been satisfied and a verbal step compliance had been obtained prior to the increase. A CR was initiated to document the missed step, 980429228.

Forty-five tests activities were completed while in Mode 1. Four tests placed transients on the Unit; 10% load swings for Advanced Digital Feedwater Control System (ADFCS) at 47%, 25% Main Turbine runback at 90%, 40% Main Turbine Runback Test at 90% and SGFP Trip test at 90%. The Heater Drain Pump testing per DCP 1EC-3692 could not be completed as scheduled in the sequencing procedure due to problems with the heater drain pumps and 12HD9. Heater Drain Pump testing was a Mode 1 test and could be completed at a later time. The sequence procedure did not require the testing to be completed prior to performing the load reject testing and it was determined to complete the testing at a later date. The testing was moved to the Post Startup testing procedure to allow closure of this procedure.

After department affirmations and NRC approval, General Manager, Salem Operations authorization was obtained allowing reactor power to be increased greater than 95% on May 1, 1998. 100% Reactor power was achieved at 0133 hours on May 2, 1998, where power remained until the fuel was conditioned at the 100% power level. On May 5, 1998, Reactor power was reduced to 90% for Heater Drain Pump testing and repair.

The 40 % Main Turbine load reject was performed on May 13, 1998 and the SGFP Trip and Main Turbine auto runback was completed on May 14, 1998. This completed the major testing required at the 100% power plateau.

UNIT 2 STARTUP

1997. Power was increased to 47% on September 2, 1997 .

The first test problem at 47% was with Digital Feedwater testing not transferring to the high power mode of operation during the power increase to the 47% Hold Point. No testing was performed from September 6, 1997 through the 8th due to I&C adjusting Nuclear Instrumentation and for performance of maintenance activities. The Digital Feedwater Control System 10% load swing was performed satisfactorily on September 11, 1997. The major maintenance activities performed during this power plateau were to troubleshoot Pressurizer level channel deviations, SGFP work due to high vibrations and to clean up the heater drain system water chemistry. The 47% power plateau requirements were completed and NRC permission was granted to proceed to the 90% power plateau on September 11, 1997.

Reactor power was increased to 54% on September 12, 1997, and stabilized for SGFP Speed Control tuning and Heater Drain Pump system testing. 21 Heater Drain Pump problems prevented completion of the testing and it was determined that the testing could be completed later when power was returned to less than 60% for the Digital Feedwater 40% load reject. Power increase was started on September 17, 1997, but due to problems with SGFP pressure transmitters and with 24 loop Delta T, was suspended for trouble shooting. These problems were resolved and power was increased to the 90% plateau on September 19, 1997. The 25% load reject was performed satisfactorily on September 21, 1997 and the Unit was returned to 90% power. The 90% power plateau requirements were completed and NRC permission was granted to proceed to 100% power on September 22, 1997.

100% Power was achieved on September 23, 1997 at 0040 hours. The 40 % Main Turbine

UNIT 1 STARTUP

UNIT 2 STARTUP

load reject was performed on September 27, 1997 and the SGFP Trip and Main Turbine auto runback were completed on September 29, 1997. This completed the major testing required at the 100% power plateau.

UNIT 1 STARTUP

UNIT 2 STARTUP

Day of Startup	Date	Event	Day of Startup	Date	Event
1	11/30/97	Entered Mode 6	1	12/16/96	Entered Mode 6
4	12/4/97	Fuel Load Complete	5	12/21/96	Fuel Load Complete
11	12/11/97	Entered Mode 5	11	12/26/96	Entered Mode 5
60	2/18/98	Entered Mode 4	175	6/14/97	Entered Mode 4
87	3/17/98	Entered Mode 3	194	7/3/97	Entered Mode 3
108	4/7/98	Entered Mode 2	239	8/17/97	Entered Mode 2
113	4/12/98	Entered Mode 1	247	8/26/97	Entered Mode 1
116	4/15/98	Reactor Power at 25%	252	8/30/97	Reactor Power at 25%
120	4/19/98	Reactor Power at 47%	255	9/2/97	Reactor Power at 47%
124	4/23/98	ADFCS 10% Load Swing Performed	264	9/11/97	ADFCS 10% Load Swing Performed
130	4/29/98	Reactor Power at 90%	272	9/19/97	Reactor Power at 90%
133	5/2/98	Reactor Power at 100%	275	9/22/97	Reactor Power at 100%