# Operational Flexibility Implementation: Case Study #3

## Extreme Turndown of a Coal-fired Drum-type Unit

2013 TECHNICAL REPORT

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*Extreme Turndown of a Coal-Fired Drum-Type Unit*

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**NOTE**

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# Acknowledgments

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# Report Summary


## Background

The case study presented in this report is the third in a series that examines the variety of challenges that electric utilities face in trying to improve flexibility in the operational performance of their generation assets. Each case is unique in both the performance goals that are sought by the utility and the equipment and operational limitations that are present.

## Objective

To reduce the minimum achievable power level during the nightly plant turndowns in order for the plants to remain competitive in the power marketplace.

## Approach

Improving the overall operational efficiency of the unit was key in ensuring its continued operating life. Previously, this unit would enter a nightly turndown cycle, where the unit would be removed from dispatch control and the operating power level would be reduced to the current minimum operating level (60 MW) in the late evening and maintained at this power level throughout the night. In the morning, the unit would be ramped back up to the minimum dispatch demand level (90 MW) and returned to dispatch control. The current minimum operating level of 60 MW was deemed too high to make the unit economically attractive to operate. To improve the economic incentive for keeping the unit in operation, a reduced minimum operating target of 42 MW was established. The goal was to conduct testing to determine whether this minimum operating target was achievable and to develop the operating procedures to allow a safe and efficient turndown to this power level on a routine basis.

During its assessment of the operating data, the project team noted that although the unit was designed to use sliding pressure control of main steam pressure during low-power operations, this feature was not being used during plant operations. Plant pressure was being maintained at or near the normal operating pressure of 2000 psig (13.79 MPa) throughout the nightly turndown and recovery. By maintaining the unit at normal operating pressure during the turndown, the main turbine system components were being subjected to increased stress with each turndown cycle evolution.

The Electric Power Research Institute (EPRI) approached the issue using a two-pronged approach and focused not only on reducing unit minimum operating level but also on establishing the use of sliding pressure control as part of the nightly turndown routine. This included the assessment of superheater, reheater, and steam turbine operating parameters to determine the optimized turndown operating strategy that delivered the best balance of economy, efficiency, and reduced equipment stress.

## Results

Because of plant limitations and material conditions encountered during initial plant testing, EPRI achieved limited success in reaching the operational target for minimum operating power level, but the use of sliding pressure control was successfully demonstrated as part of a proposed operating strategy for nightly turndown operation.


## Keywords

Coal-fired drum boiler
NOx
Operational flexibility
Sliding pressure
Turndown

# Executive Summary

The Electric Power Research Institute (EPRI) conducted low-power testing using plant data, procedures, and information gathered during preliminary work to support the operational flexibility low-power testing project. The testing was affected to implement and test procedural changes proposed to achieve the operating goal of reducing the minimum plant loading level during nightly turndown evolutions, thereby increasing overall plant efficiency and operational flexibility. The low-power testing was conducted by EPRI in conjunction with the utility's engineering and operations department.

The objective of the low-power testing was to reach a stable operating power level at a target goal of 42MW during testing and to determine whether this goal was safely achievable as a minimum operating target for nightly turndown operations. Lessons learned from the testing process were to be incorporated into the final recommendations for procedural and equipment modifications required to allow consistent operation at the target minimum operating level.

The low-power testing evolution was initiated as planned, but equipment deficiencies uncovered during the load ramp prevented reaching the target load level of 42MW. A stable operating level of 50MW was achieved prior to suspending the testing process. The limited testing that was accomplished provided both proof of concept and operational limitations for the overall strategies proposed as part of the low-power operations program, including the following:

- The use of sliding pressure control
- The use of lower mills and burner tilts to control steam temperatures
- The use of limited wall blower operation to control steam temperatures
- The use of overfire air dampers to aid in NOx control during low-power operation
- The use of lower mills to aid in NOx control during low-power operation

Following the initial test attempt, a list of the equipment deficiencies preventing completion of testing was compiled. The plan going forward was to correct the equipment deficiencies identified during the next unit outage and then to make another attempt at completing the testing.

A second attempt was made to continue the low-power testing process, but because of extenuating circumstances (other units in the fleet experiencing unscheduled downtime), the plant could not support lowering load on the unit to support the testing process.

A detailed breakdown of the test results is included in this report.

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# Section 1: Introduction

EPRI was asked by the utility to conduct an Operational Flexibility Case Study at one of their older coal-fired drum-type units for the purpose of determining the maximum turndown the unit was capable of safely sustaining. The project was kicked off in February of 2012 with plant data gathering and formulation of a testing strategy to support the overall project goals.

The first on site testing session was scheduled and conducted in September of 2012. The plant was made available during the midnight shift and the testing was conducted concurrent to the normal plant turndown run for that evening. Due to equipment limitations and material issues encountered during the testing the target power level for the test was not achieved, and limited test data was obtained.

After the plant's scheduled outage, another attempt was made to continue the low power testing program in March of 2013, following the correction of equipment issues encountered during the first test. Unfortunately unscheduled outage issues with other units in the fleet precluded another round of testing.

# Section 2: Plant Overview

The test unit consists of a 200 Megawatt conventional fired coal fired boiler and cross compound steam turbine. The boiler is a forced circulation unit with a split superheat and reheat furnace. The first (superheat) furnace contains water walls, primary and secondary superheaters along with an economizer. The second (reheat) furnace contains water walls, primary superheater, and reheater along with an economizer. Both furnace sections share a common steam drum.

The condensate and feedwater system utilize turbine extraction for feedwater heating. The condensate and feedwater system consists of condensate, feedwater heater, and boiler feed pumps without the use of a Deaerator. The feedwater heater or booster pumps are driven from one end of a constant speed AC motor with a variable speed coupling driving the boiler feed pump on the other end. Boiler drum level is controlled utilizing split range feedwater regulating valves provided with a constant 250 psig feedwater differential from the variable speed boiler feed pumps. One controller operates both the main feedwater regulating valve, and a smaller bypass valve used during lower loads and unit startup.

Feedwater heating consists of two parallel strings of high pressure heaters (located after the boiler feed pump discharge) and five stages of low pressure heaters (located between the heater feed pumps and boiler feed pumps). Seal water is required from the boiler feed pumps to the boiler circulating water pumps any time the boiler pressure exceeds 250 psig. Boiler circulating water pump seal water regulators maintain seal water pressure at 100 psig above drum pressure.

During normal full load operation two condensate pumps, two heater feed pumps, and two boiler feed pumps are required. After unit loading is dropped below 120 megawatts one boiler feed pump is shutdown along with its corresponding feedwater booster pump (both driven by the same boiler feed pump motor).

The steam turbine consists of a cross compound turbine with the HP/IP turbine operating at 3600 rpm on one shaft and the LP turbine operating at 1800 rpm on a second shaft. The turbine controls consist of a mechanical hydraulic control system with a single hydraulic actuator for each set of turbine governor valves. The cam operated control valves can only operate in a partial arc admission mode after steam flow control has been shifted from the throttle valves to the governor valves.

The unit controls allow operation of the unit in a coordinated, boiler follow, or turbine follow control mode. Normal operation utilizes AGC control until unit loading has been reduced below 90 megawatts.

The boiler configuration and plant procedures require gas ignitor operation when starting and shutting down pulverizers. Each boiler furnace has four pulverizers with volumetric coal feeders. The boiler is corner fired with burner tilts for superheat and reheat temperature control. Although superheat and reheat attemperators are designed on the boiler they are currently not operational, since normal unit operation does not require attemperation. ID fans provide balanced draft operation on both the superheat and reheat furnaces. Three regenerative air heaters provide the primary and secondary air heating for plant operation. One air heater serves the superheat and one the reheat furnaces. The middle (third) air heater receives flue gas from both furnaces and supplies primary and secondary air to both.

Combustion air flow is controlled with a combination of FD fan operation, secondary air dampers, and fuel and aux air dampers on each boiler corner. The secondary air dampers along with overfire air dampers modification provide NOx control for both furnaces. The secondary air damper providing each furnace response to excess O2 leaving the respective furnaces while the aux air dampers at each corner control windbox to furnace differential pressures. The fuel air dampers operate according to the feeder speed supplying coal to the respective coal burner.

The plant environmental equipment consists of electrostatic precipitators. SO2 levels are controlled by burning low sulfur western coal. NOx emissions are controlled using the low NOx modifications made to the boiler.

# Section 3: Test Procedure

Current plant operating strategy requires a drop in unit loading to minimum each evening and a return to full unit loading the next morning. The boiler is designed to burn waste gas from a nearby industrial facility. Approximately 25 megawatts of unit loading can be obtained utilizing the gas ignitors inside the boiler. Supplemental gas firing is occasionally used to augment unit loading. Normal plant operation would be for AGC to drop unit loading over time during the evening hours. At approximately 12 midnight the unit operator takes control of the unit and reduces load as low a practical until the load run up during the morning hours. Prior to test, the unit would maintain design 2000 psig pressure with occasional pressure drop down to 1900 psig. When operating upper pulverizers to maintain superheat and reheat temperatures an elevation in unit NOx was experienced. When operating on lower pulverizers unusually low superheat and reheat temperature were experienced. The overfire air damper operation is automatically controlled without the ability for operator interventions. At approximately 90 megawatts the overfire air dampers drive to minimum resulting in a NOx increase above 0.35 lbm/MMBtu. During lower mill operation the NOx remained in the .16 ppm range.

During the testing, a plan was put into place to manually hold the overfire air dampers to approximately 15% during upper mill operation but the control system maintained a lock on the controls preventing operator intervention. Sliding pressure operation was one principal anticipated to be used during the testing to improve low power operation. Concerns during this mode of operation included:

1. Without the use of attemperators to control steam temperature, there was concerns associated with excessive steam temperature operation during sliding pressure operation.
2. The ability to maintain boiler drum level control in automatic deteriorates during low load sliding pressure operation.
3. With the use of MHC controls there was a concern with operation of the turbine valves at a crack point on individual control valves since only hydraulic valve operator position was provided to the control room operator.
4. Limited mobility of the furnace tilts and their use to help control steam temperatures.

5. Limited controls on sootblower operation and some limited sootblowing capabilities.
6. Some known problems with gas ignitor operation.
7. Some known flame scanner issues/limitations.

# Section 4: Test Description and Results

During test 1 the test plan included sliding pressure operation, with a pressure slide down to 800 to 1200 psig. The test strategy also included the use of lower mills and burner tilts to control steam temperatures. The operators typically operated either upper (top two mills) or lower (bottom two mills). This may be a carryover from earlier plant limitations due to split wind box operation between the upper and lower mills. At the start of the evolution the operator was having problems with lower ignitors on the Superheat furnace and decided to shut them down first since the ignitors may be needed at the lower load points for flame stability on the remaining pulverizers. At the start of this test, the control room operator was at 120 megawatts with the turbine valves already at the 35% position. A pressure slide was commenced during the initial load drop by dispatch down to 90 megawatts. At approximately 90 megawatts and 1700 psig on the throttle, main steam temperature had increased to 1025°F (1050°F is the design temperature limit for the turbine). The burner tilts were lowered to control the steam temperature with only minimal effect. The control operator commenced a lower sequence soot blow of the SH furnace walls to limit the main steam temperature. The final result of both the tilt operation and sootblowing reduced the steam temperature down to 950°F. It was discussed that more sootblowers were blown than necessary to control the main steam temperature.

At this point a load reduction was initiated, with an end goal of the minimum operating target of 42 MW. At approximately 50 megawatts, the flame indications were weak on the operating mills. The operator was unable to get the gas ignitors in the upper mill, and had a faulty scanner on the next lower mill. To prevent a possible loss of flame the unit load was increased above 60 megawatts. The operator attempted to shift to a lower set of mills but there were two faulty scanners on the next lower mill on the superheat furnace. The test was halted until improved gas burner operation and scanner operation could be obtained.

The following is a comparison of a unit load drop to 60 MW in full pressure operation and 50 MW in sliding pressure operation. In both cases the upper pulverizers were used to maintain steam temperatures to the HP and IP turbines. Sliding pressure was used to keep the steam temperatures higher and to limit the temperature drop on the HP turbine first stage.

Plant Net MW data is shown in Figure 4-1 below for the test run (red) and the reference run conducted using current plant standard procedures. In the reference run plant load is lowered from approximately 120 to 90 MW while on AGC control, and then manually lowered to approximately 65 MW for the evening turndown. In the test run, plant load was initially lowered from 120 MW to 90 MW as the pressure slide from 2000 psig was commenced. Load was held at 90 MW while a lower wall blower sequence was conducted to lower superheat steam temperature. Following the blow, power was further lowered to the 50 MW level, and the pressure slide was continued. After a short time (approximately 20 minutes) operating at 50 MW, further attempts to remove additional mills were unsuccessful due to a combination of ignitor and flame scanner issues. The decision was made to return loading to above 60 MW.

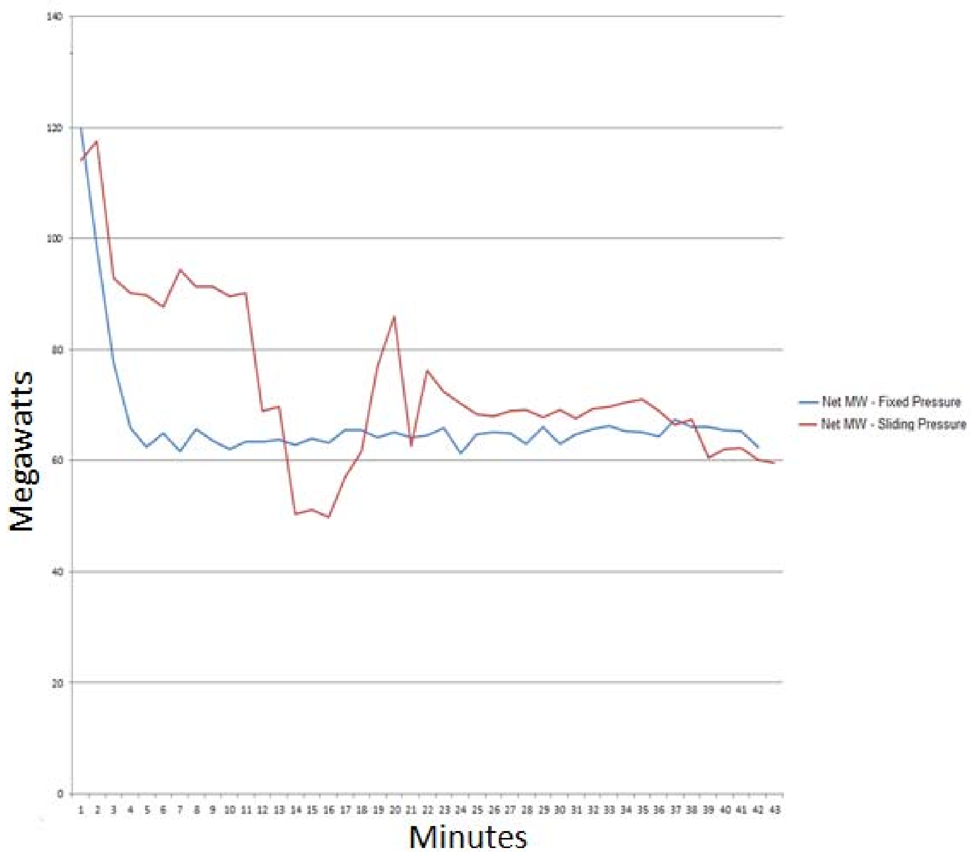


*Figure 4-1*
*Unit 2 Net MW*

Main steam pressure is shown in Figure 4-2 below. The figure shows pressure being held steady during the reference run (blue) at plant normal operating pressure of 2000 psig. The test run pressure (red) is ramped down during the test run. A brief hold occurs at approximately 1700 psig while the lower waterwall blow sequence is initiated to control superheat temperature. Following the blow, the pressure ramp is continued down to 1400 psig. Subsequent reduction down to the 800 – 1200 psig range was planned, but when the load drop to the target MW level was aborted and load was raised back above 60 MW, further pressure reduction was halted.

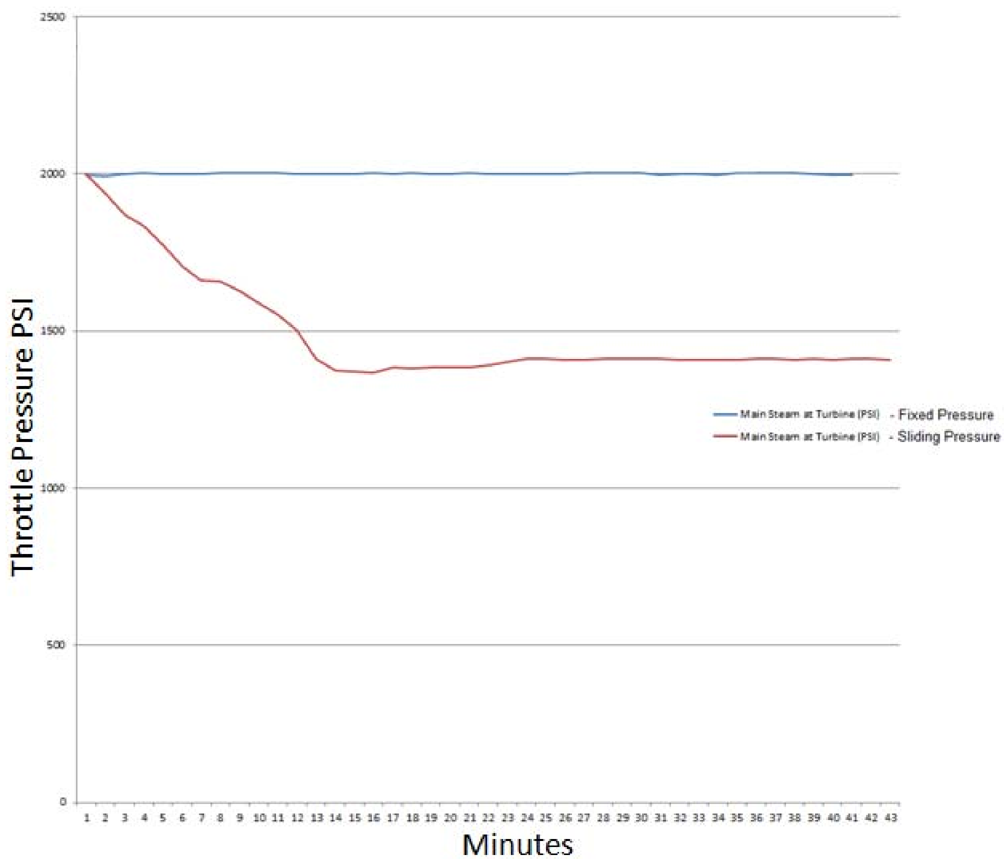


*Figure 4-2*
*Main Steam Pressure*

Superheat final temperature is shown in Figure 4-3 below. Superheat temperature for the reference run (blue) shows an initial drop which follows the load drop closely, and then displays normal operational fluctuations. Temperature for the test run (red) shows an immediate increase which corresponds to the pressure drop, and continues to approximately 1003°F. The rise is initially turned by the hold in the pressure slide, and ultimately reduced by the wall blower sequence performed on the lower waterwall tubes. Following the blow, temperature increases slightly with the load reduction down to 50 MW, and then drops to the same approximate level as that of the reference run when load is returned above 60 MW.

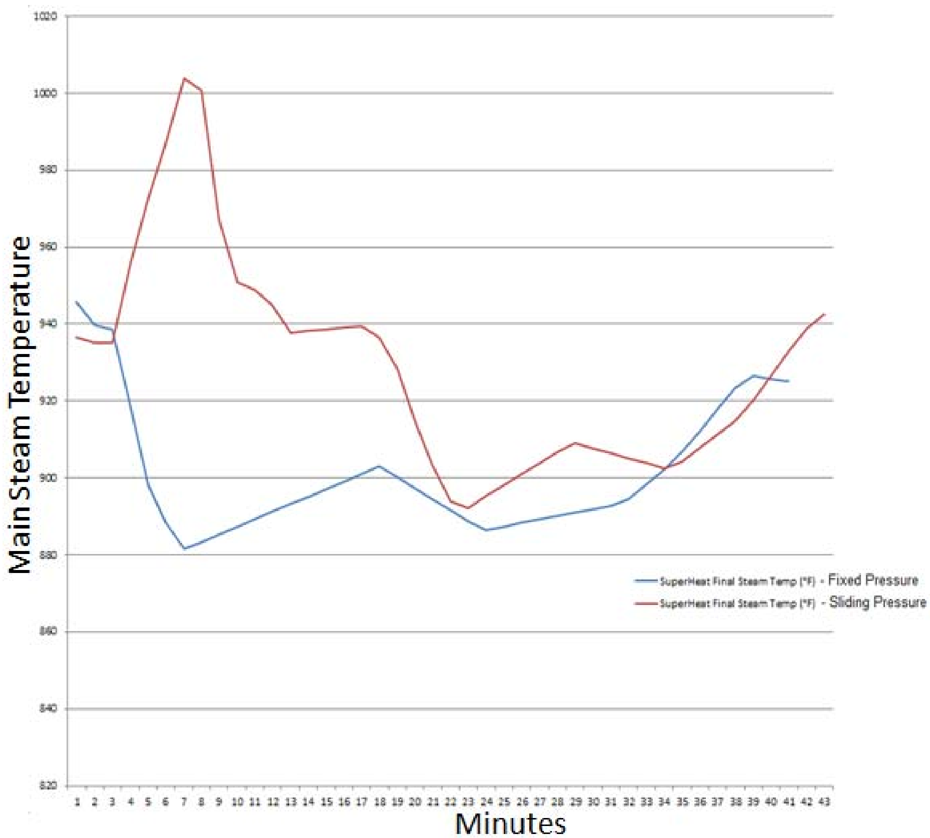


*Figure 4-3*
*Superheat Final Steam Temperature*

Main turbine first stage pressure is shown in Figure 4-4 below. First stage pressure mirrors unit load for both the reference run (blue) and the test run (red).

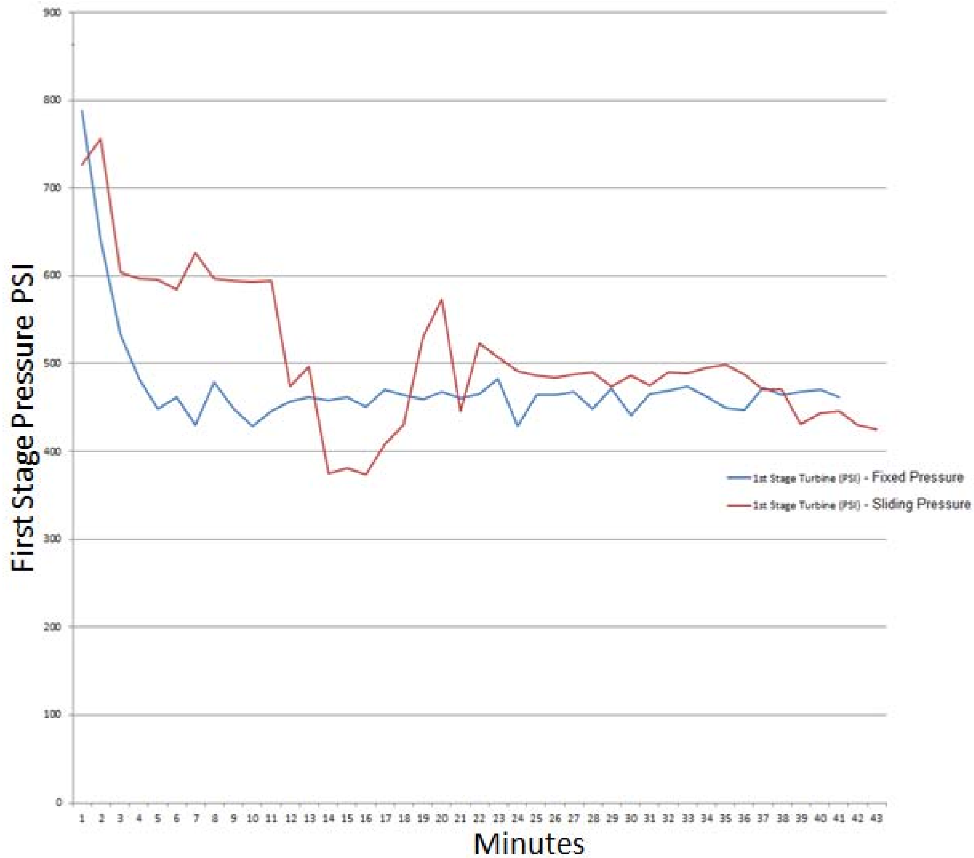


*Figure 4-4*
*Main Turbine First Stage Pressure*

Main turbine first stage temperature is shown in Figure 4-5 below. The reference run (blue) shows an initial drop which follows, but lags the load drop slightly. The test run (red) increases initially, following the increase in superheat final temperature, then drops following both the wall blow sequence and the load reduction.

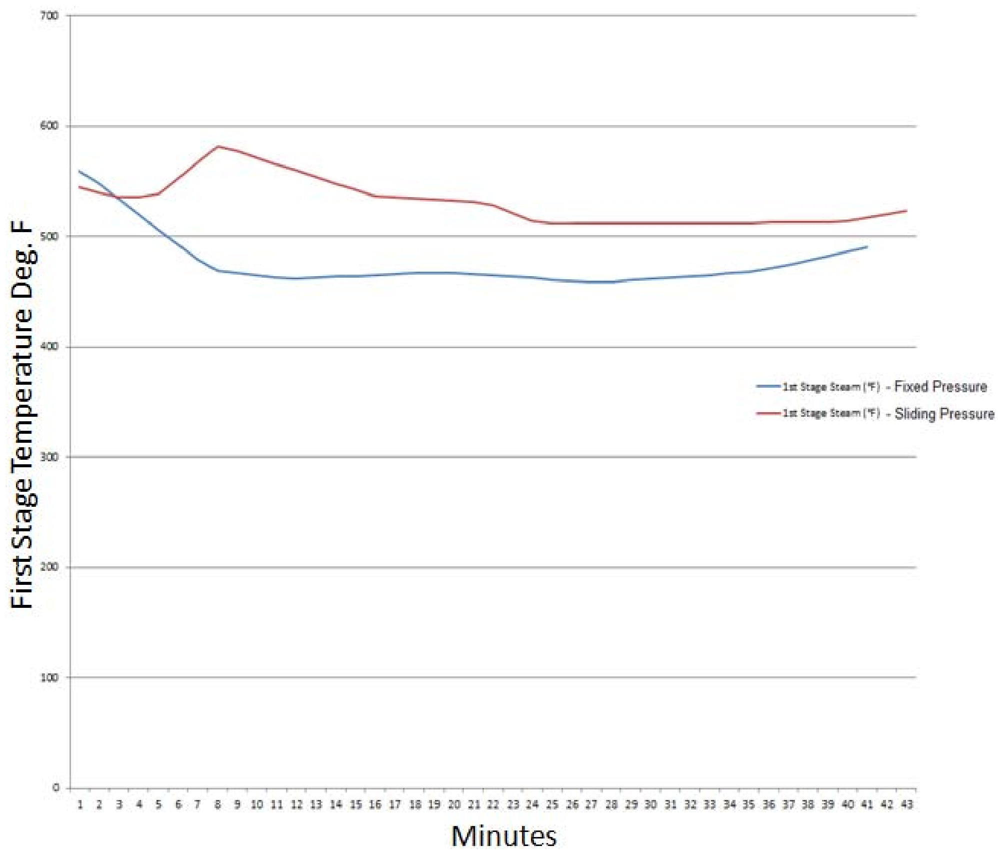


*Figure 4-5*
*Main Turbine First Stage Temperature*

The turbine governor valve positions are shown in Figure 4-6 below. The reference run (red and purple) show the initial drop in throttle valve position corresponding to the load drop to the turndown power level, followed by normal operating fluctuations throughout the reference run. The test run (blue and green traces) mirror the initial power reduction, and hold/slight increase while superheat temperature is addressed, followed by the reduction corresponding to the load drop to 50 MW, and subsequent increase to above 60 MW. The governor valve positions are greater than those for the reference run for all equivalent load points, due to the sliding pressure strategy implemented as part of the test run. This reduces throttling losses across the governor valves, and increases overall efficiency.

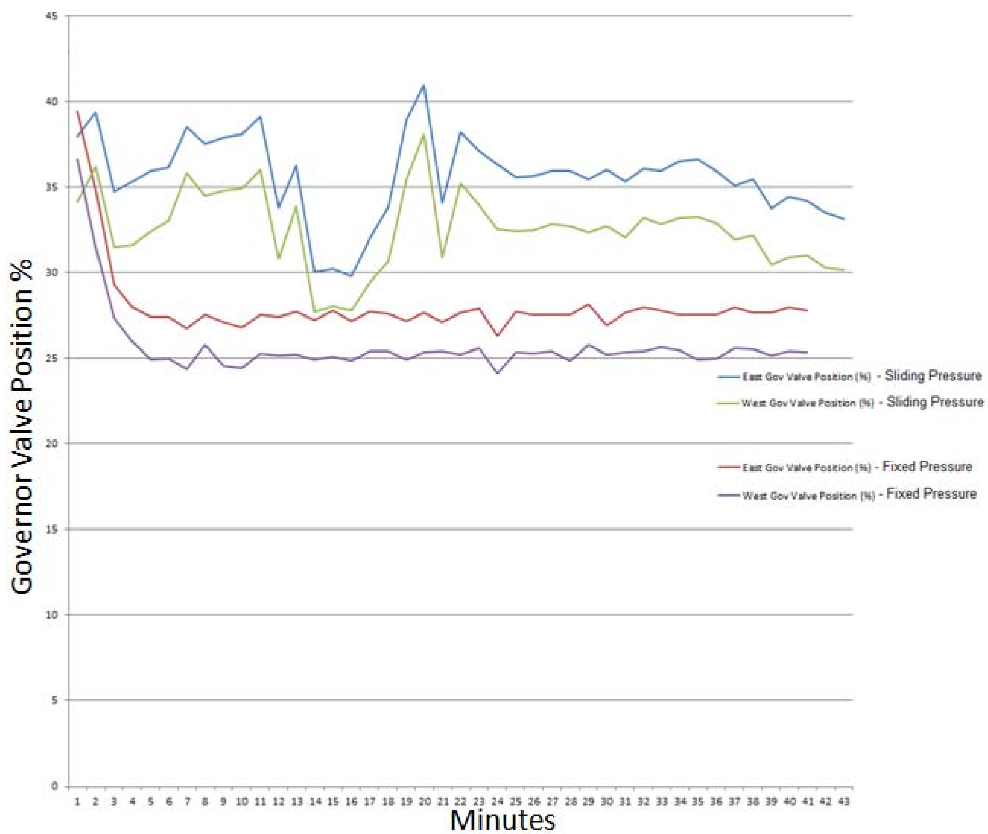


*Figure 4-6*
*Turbine Governor Valve Position*

HP and IP turbine efficiency are shown in Figure 4-7 below. The HP and IP efficiency for the reference run are shown in the red and purple traces. The HP and IP efficiency for the test run are shown in the blue and green traces. IP turbine efficiency remains relatively flat throughout the run for both the reference and test conditions. Reference HP efficiency drops with the load increase and then remains relatively flat, to slightly increasing during the reference run. HP efficiency remains initially flat during the ramp from 120 MW to 90 MW, and then drops with the load reduction to 50 MW, though maintaining well above reference HP efficiency. The test HP efficiency rebounds as the test run load is increased above 60 MW.

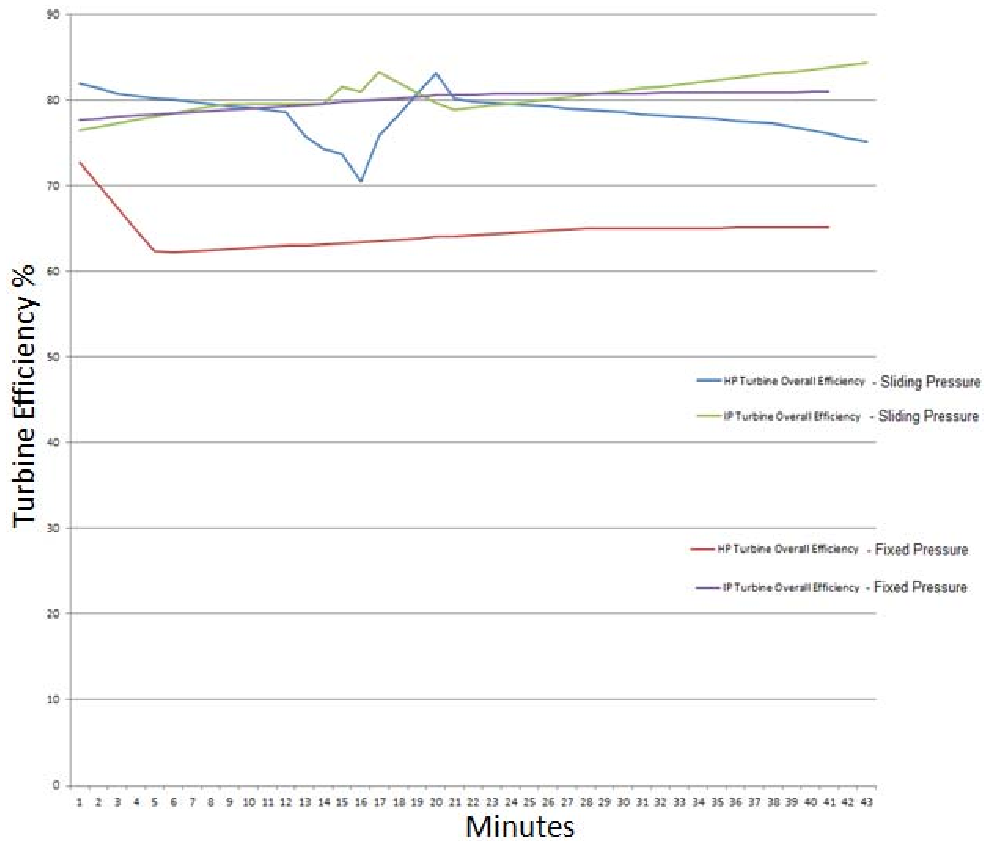


*Figure 4-7*
*HP/IP Turbine Efficiency*

The unit overall NOx output is shown in Figure 4-8. The NOx level for the reference run (blue) increases from the normal operating value of approximately 0.16 lbm/MMBtu, to a level of approximately 0.27 lbm/MMBtu as load is reduced during the reference run. The NOx level for the test run (red) shows an initial increase as the load reduction is started. A drop occurs at approximately time 3 as one of the upper level mills in the SH furnace is removed from service. A further reduction is seen as superheat temperature is reduced by the lower waterwall blow. A large increase is seen accompanying the load reduction to 50 MW. This is unable to be mitigated due to equipment issues preventing the operation of lower level mills, and the lockout of the overfire air (OFA) dampers below a load level of 90 MW. Following the return of load above the 60 MW point, the NOx levels return to a corresponding baseline level, until approximately time pint 36, where they increase in response to a corresponding increase in SH final temperature.

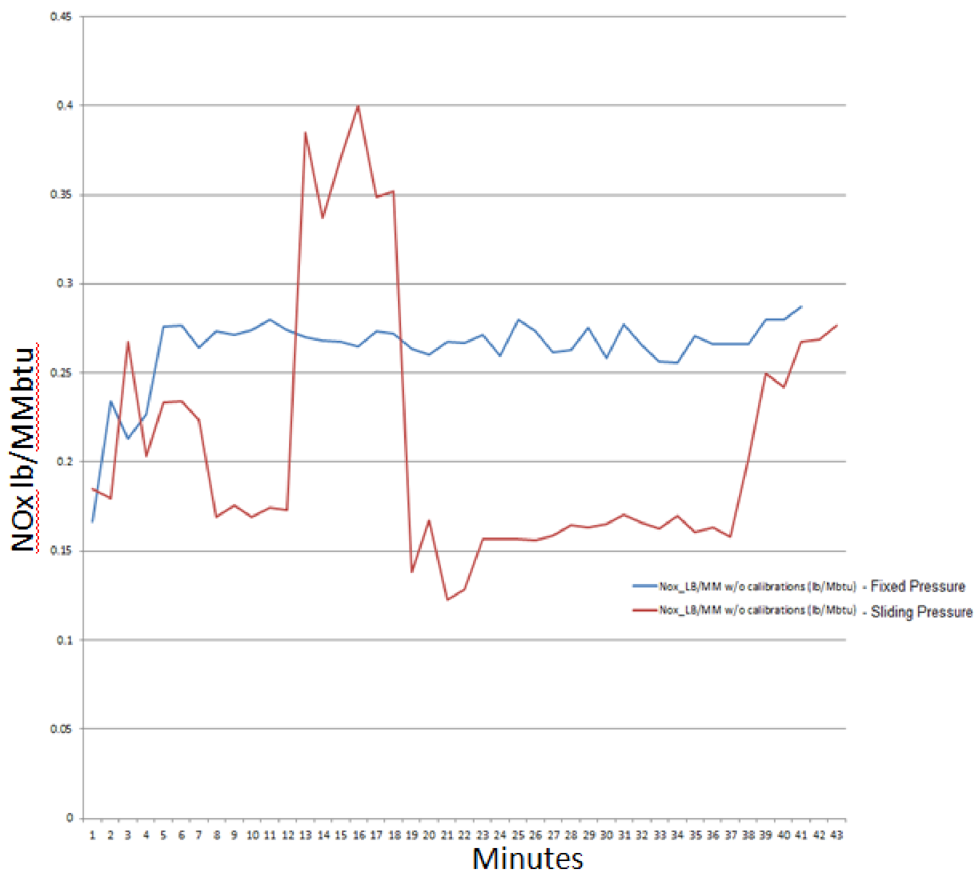


*Figure 4-8*
*Unit Overall NOx Output*

# Section 5: Recommendations

Based on test results analyzed, EPRI proposed the following near-term recommendations:

- Equipment Repairs or Upgrades
  - The following equipment should be repaired or replaced as required to be returned to full functionality:
    - Ignitors
    - Flame Scanners
    - Burner tilt mechanisms
  - Main Steam Attemperators
    - Consideration should be given to restoring the main steam attemperator functionality. Based on discussions with plant personnel, the operability of this equipment would be useful during other plant operational situations, other than just during minimum power turndown operations.
- Instrumentation and Controls Changes
  - Control logic changes to the overfire air damper controls
    - Implementation of control logic changes to the OFA damper controls would provide an additional control mechanism to the operator for NOx control during minimum power turn down operations. The current operational strategy of driving the dampers to a minimum position, and interlocking them in this position below 90 MW leaves selectively operating the lower elevation mills as the only viable avenue of NOx control. Additionally, plant personnel expressed concern with the ability to maintain steam temperatures (steam temperatures lower than normal) when operating only the lower mill elevations.

# Section 6: Benefits of Recommended Changes

While the overall goal of the low power testing program was not achieved, and the ability to operate at the target level of 42 MW was not demonstrated, the testing that was accomplished did provide useful information that can be applied to turndown operations. Several key equipment and material issues were identified as part of the testing program. These equipment issues should be targeted to be addressed and corrected during the normal unit periodic maintenance outage. Correction of these deficiencies not only supports enhanced capabilities while operating at low power, it increases overall plant reliability and redundancy at all operating conditions. Information gathered in the testing program is already being applied to plant operations as part of the plant deslagging procedure which is included in Appendix A. A proposed minimum power for turn downs procedure is included in Appendix B.

Benefits: The overall operating benefits of the concepts demonstrated in the low power testing program led to improved plant operational and economic efficiency and should decrease maintenance costs and extend equipment life in the long term. These benefits include four key results which drive this increased efficiency, which are:

- Extended temperature control – The unit is better able to maintain reheat and throttle temperatures at lower loads with sliding pressure operation.
- Lower boiler feed pump work – Lower pressures in the boiler drum mean less work required by the boiler feed pump.
- Reduced throttle losses – By sliding pressure rather than throttling using the governor valves, turbine efficiency increases.
- Higher governing stage exit temperatures – Turbine manufacturers recommend sliding pressure to reduce thermal stresses across the HP turbine during load changes at low power operation.

# Appendix A: Unit Deslagging Procedure

| 1. Unit 1 – Perform Boiler Deslag | | | | |
|---|---|---|---|---|
| **Division** | 2. Fossil Generation | **Group** | 3. Power Plant Operation | |
| **Reference** | J. Hart | **Date** | 7/24/2006 | /S/ R. Sausser |

### System Description

Excessive slagging in the furnace can affect the boiler performance resulting in forced reduction of megawatts because of high exit gas temperatures, high main steam temperatures, and ultimately a boiler outage due to pluggage.

Slagging is caused by the formation of molten or partially molten ash particles deposited on tube surfaces when ash in liquid phase is resolidified by the quenching effect of the tube surface that is of lower temperature than the combustion gas. Slagging usually occurs in the furnace and can extend to the convection pass if flue gas temperature is not sufficiently reduced. Fouling will generally occur in the Secondary Superheater and Reheater areas and is caused by the vaporization of inorganic elements that condense on tube surface and combine with ash particles. Condensing of these elements on the tubes and ash particles facilitate bonding of ash/slag to tube surfaces.

Once slagging or fouling begins, deposits accumulate and extend from tube surfaces. As deposits enlarge, deposit surfaces are significantly higher in temperature than tube surfaces. When this occurs, the melting point of more of the ash particles is exceeded and deposit surface becomes molten or semi-molten. Slagging is then accelerated as the temperatures are usually sufficient to fuse or melt all ash particles into fluid state. Temperature must be reduced sufficiently before leaving the furnace (at nose arch) to re-solidify ash particles so they bounce off of tubes back into the gas stream or deposited as a dry powdery substance easily removed by sootblowing.

The root cause of excessive slagging is furnace exit gas temperature higher than ash fusion temperatures. Furnace gas temperature must be depressed below fluid ash fusion temperature before passing over the nose arch (Furnace Exit).

Temperature above fluid ash temperature will almost guarantee a slagging problem. Temperature above ash softening and hemispherical temperature can also make slagging very likely.

Deslagging on line is a method of removing the excessive slag.

The unit is scheduled every Saturday night after the system load has decreased to allow the unit to come down to minimum. If an additional deslag is necessary, the Control Room Operator will call Merchant Operations requesting a deslag for that night.

## Safety

1. Participate in Continuous Job Hazard Analysis.
2. Conduct/Participate in a Pre Job Briefing (PJB), including but not limited to:
    - Slip/Fall Hazards
    - Environmental Issues
        - Dispose of used batteries according to regulations.
    - Spill Hazards
    - Additional special hazards
    - Proper Personal Protective Equipment
        - Hard hat, safety glasses, hearing protection, safety shoes
    - Proper protective clothing must be worn at all times (FRC)
        - The FRC program applies to all employees who have the potential for exposure to arc flash and flash fire (Refer to JIT 3E-08-10)
        - Operators set Arc Protection boundaries to protect people from the hazards of arc flash and arc blast (Refer to JIT 3E-08-11)
    - Be aware of changing conditions
        - Stop work and hold another PJB if conditions change

## Operator Functions/Job Duties/Responsibilities

After the Merchant Operation releases the unit for a deslag the following steps are taken:

1. Take the unit off AGC if system has control.
2. Lower load on the unit to 60 net megawatts at a rate of 4-6 megawatts per minute.
    - Take off 1 and 8 mills first if possible.
    - Take off 2 and 7 mills if possible.
    - Adhere to turbine metal temperature limits.
    - Adhere to opacity limits.

- Watch flame scanners at lower loads. Do not use gas to maintain flame scanner stability at lower loads. If gas is necessary for more than momentary stabilization, raise load until it is no longer needed.

If walls are extremely dirty, sliding pressure can help to clean them. If walls and back passes are evenly slagged, lower load will be more beneficial than sliding the pressure. To slide pressure:

3. Decrease set point on initial pressure regulator to 1600psi.
4. Set throttle pressure rate of change to 8 psi/min.
5. Slide (reduce) throttle pressure to 1600psig.
   - Furnace will shrink as pressure decreases.
6. Blow wall blower sequences to help remove any loosened deposits.
7. Return throttle pressure to 2000psig.
8. Notify MOC that deslag is finished and unit is available for dispatch.
9. Ensure that a derate entry for deslag is made in P3M from time unit was released by Merchant Operations until time unit is made available for dispatch.
   - Use MPAC Id: 06E10600 (Boiler).
   - Use NERC Code: 920 (other slag and ash removal problems)
   - Use Failure Code: F115 (cleaning).
   - Use Event Type: NC (non-curtailing equipment outage).

# Appendix B: Minimum Power Turndown Operating Procedure

| 1. Unit 2 – Minimum Power Operation for Nightly Turndown | | | | |
|---|---|---|---|---|
| **Division** | 2. Fossil Generation | **Group** | 3. Power Plant Operation | |
| **Reference** | | **Date** | | |

## System Description

The unit is scheduled every night after the system load has decreased to allow the unit loading to come down to minimum. The following procedure is designed to maximize efficiency while safely lowering unit load, utilizing sliding pressure control, to the minimum consistently achievable level.

## Safety

1. Participate in Continuous Job Hazard Analysis
2. Conduct/Participate in a Pre Job Briefing (PJB), including but not limited to:
   - Slip/Fall Hazards
   - Environmental Issues
     - Dispose of used batteries according to regulations
   - Spill Hazards
   - Additional special hazards
   - Proper Personal Protective Equipment
     - Hard hat, safety glasses, hearing protection, safety shoes
   - Proper protective clothing must be worn at all times (FRC)
     - The FRC program applies to all employees who have the potential for exposure to arc flash and flash fire (Refer to JIT 3E-08-10)
     - Operators set Arc Protection boundaries to protect people from the hazards of arc flash and arc blast (Refer to JIT 3E-08-11)

- Be aware of changing conditions
    - Stop work and hold another PJB if conditions change

## Operator Functions/Job Duties/Responsibilities

After the Merchant Operation releases the unit for nightly turndown the following steps are taken:

1. Take the unit off AGC if system has control
    - Sliding pressure operation should be initiated in conjunction with the nightly turndown evolution

To slide pressure:

2. Decrease set point on initial pressure regulator to 1200psi
3. Set throttle pressure rate of change to 8 psi/min
4. Slide (reduce) throttle pressure to 1200psig
5. Lower load on the unit to 50 net megawatts at a rate of 4-6 megawatts per minute
    - Take off 1 and 8 mills first if possible
    - Take off 2 and 7 mills if possible
    - Adhere to turbine metal temperature limits
    - Adhere to opacity limits
    - Watch flame scanners at lower loads. Do not use gas to maintain flame scanner stability at lower loads. If gas is necessary for more than momentary stabilization, raise load until it is no longer needed.
6. Monitor main steam temperature during the pressure and load ramp. Perform the following actions to maintain main steam temperature below the design limit of 1050F:
    - Lower the boiler tilts fully
    - Blow lower wall blowers in the SH furnace (Note: limit wall blowing to that which is necessary to maintain Main Steam temperature in the desired range. Excess operation of wall blowers will result in further lowering main steam temperature unnecessarily.)

After the evening turndown period the following steps are taken to prepare the unit for return to system loading:

7. Return throttle pressure to 2000psig
8. Return unit loading to normal, non-turndown minimum loading level (90MW)
9. Notify MOC that unit is available for dispatch

**Export Control Restrictions**

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