

B&W's NO_x Reduction Systems and Equipment at Moss Landing Power Plant

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Abstract

California's Monterey Bay Unified Air Pollution Control District (MBUAPD) rule 431 requires NO_x emissions to be less than 10 ppm by January 1, 2002 for Units 6 and 7 at Duke Energy's Moss Landing Power Plant near San Francisco. B&W developed a design in an alliance arrangement with the previous owner, Pacific Gas & Electric, to retrofit an SCR to Unit 7. (Rule 431 was modified to slightly defer the SCR on Unit 7, replace the original burners on Units 6 and 7 with B&W's XCL-S™ low NO_x burners and install overfire air ports.) The modified Rule 431 requires one unit to be at 10 ppm maximum NO_x with less than 10 ppm slip after December 31, 2000 and the second unit in compliance after December 31, 2001.

Unit Background

Moss Landing Units 6 and 7 are oil- and gas-fired 750 MW_e Babcock & Wilcox Universal Pressure (supercritical) type boilers, operational in 1967 and 1968. Each unit has a continuous steam flow capacity of 5.1 million lb/hr at 3,830 psig and 1005F at the superheater outlet under clean conditions while firing natural gas. The furnace is 54 ft wide by 36 ft deep with a single division wall. The furnace height is 128 ft from the hopper headers to the roof tubes.

These units were originally equipped with 48 B&W circular burners in 16 three-high cells. The cells were arranged in a four wide by two high pattern on both the front and rear boiler walls. During 1971 and 1972, the units were modified with flue gas recirculation (FGR), added to the secondary air system. This completed the first phase of NO_x control at Moss Landing Power Plant.

The top burner in each upper cell was converted to operate as an overfire air port to provide limited air staging for NO_x control. In this mode, the top burners run out-of-service, providing air only to the overall combustion process.

The units are capable of directing FGR flow through the hopper and/or mixing foils in the air duct feeding the windbox for NO_x control and/or steam temperature control. The boilers are pressure-fired with a current positive operating furnace pressure of about 23 in. w.g. with alarm point of 24 in. w.g.

Current Operation and Limiting Factors

Units 6 and 7 currently operate from 50 MW_e to 750 MW_e depending on demand. Each unit operates on the bypass system up to about 160 MW_e. The units are then transferred to once-through operation.

The original NO_x control design used flue gas recirculation for furnace protection and reheat steam temperature

control to about 80% load. The FGR at this point was reduced to minimum value with one fan still in service and the flue gas biasing dampers were used to control reheat steam temperature. In 1971, flue gas recirculation fans were replaced with higher static fans to direct flue gas to the secondary air to reduce NO_x. However, increased FGR resulted in operating the furnace near the alarm point when FGR was maximized at full load. Reheat spray is used to reduce furnace-operating pressure by allowing more flue gas to flow over the horizontal reheater and reducing convection pass draft requirements.

The result of previous NO_x reduction work has pushed some original equipment near its original design limit.

Current NO_x limits are 90 ppm corrected to 3% O₂ from full load of 750 MW down to 460 MW. Below 460 MW, the emissions per boiler are on a pounds per hour basis. Full load NO_x emissions are controlled by staged combustion and flue gas recirculation (FGR) to the secondary air stream. The downside to using FGR at full load to control NO_x is that the FD fans operate at maximum static output and high furnace pressure. To reduce system operating resistance, the gas-biasing damper on the reheat section is opened with reheat spray required to control hot reheat steam temperature.

SCR Project Development

To define scope for the new NO_x reduction program, Duke Energy, purchaser of Moss Landing Power Plant, met with B&W in the summer of 1998 to review the status of work done with the plant's former owner.

As part of the cost-benefit analysis in adding an SCR to Unit 7, new B&W low-NO_x XCL-S™ burners and overfire air ports were part of the overall scope. B&W provided technical support to the former owner in petitioning the Monterey Bay Unified Air Pollution Control District (MBUAPCD) to modify Rule 431 to defer the SCR addition on Unit 7 by installing low-NO_x burners on both Units. Rule 431 was modified for NO_x firing natural gas from 10 ppm for Unit 7 and 225 ppm for Unit 6 to 90 ppm on both units. The modified Rule 431 requires one unit must be at 10 ppm maximum NO_x with less than 10 ppm slip after December 31, 2000 and the second unit in compliance after December 31, 2001.

Duke Energy issued an order to B&W for an engineering study for a new design based upon Duke Energy criteria. During the fall of 1998 Duke Energy and B&W met regularly to discuss status and provide direction for project design.

The deliverable from the engineering study was a firm price to engineer, procure, and install selective catalytic reduction (SCR) systems on Units 6 and 7 plus design of the ammonia storage area. Each SCR system includes new forced draft fans and motors, addition of induced draft fans and motors, structural steel, foundations, and new flues and ducts. (See Exhibit 1.)

Duke Energy purchased the honeycomb-type SCR catalyst directly from Cormetech, Inc. with purchase order assignment to B&W for project coordination and demonstration of system guarantees. The engineering study provided the design conditions for the Duke Energy specification to Cormetech.

Cormetech is coordinating the cold flow model work with B&W providing flue, reactor, and ammonia injection grid design.

Other projects, concurrent with the SCR retrofit on Unit 6 are:

- Major turbine overhaul.
- Boiler/turbine control upgrade including a new building to house DCS controls for Units 6 and 7 and future combine cycle units.
- Two new 500 MW combined cycle units with inlet and outlet seawater cooling lines for the condenser.
- Fuel oil storage tank demolition, replacement of some feedwater heaters, and ammonia tank farm.
- New make-up water system.

Site coordination meetings began in October 1999 to facilitate technical exchange with other projects and construction schedule-planning interface into an overall site schedule.

Scope of Supply and Equipment Description

Duke Energy assumed ownership of Moss Landing Power Plant on July 1, 1998, and requested a meeting with B&W in August to review the previous SCR design work on and status of Unit 7. Duke Energy awarded B&W an engineering study contract in September 1998 to develop a design that met the long-term needs of a merchant power plant.

Duke and B&W met every two weeks to review design progress which included plant operational concerns and constructability. Design criteria were jointly established during the preliminary engineering phase since a formal technical specification was not available at the beginning of the project.

Some of the key issues with SCR design include boiler/SCR compatibility, catalyst and SCR system supplier interface, and modeling. It is imperative that any NO_x control system be designed to operate in conjunction with the boiler. These units have FGR for NO_x control and reheat steam temperature control at low load plus biasing

dampers at the exit of the two convection pass gas passes (Figure 1). Previous boiler modifications and planned design changes consumed design margins in most equipment.

For Units 6 and 7, B&W is the turnkey supplier for the SCR and the ammonia system except for the catalyst supply. Duke Energy purchased the catalyst directly from Cormetech and assigned the purchase order to B&W for design coordination responsibility.

Arrangement

Early studies indicated that a horizontal flow, in-duct SCR reactor was a cost-effective arrangement for the performance conditions. A design review of the earlier arrangement with its limitations, and future operating needs, resulted in an arrangement that placed the SCR reactor outside of the in-line flue between the economizer outlet and air heater inlet.

The optimum operating arrangement places the reactor in a vertical downflow arrangement above the air heaters with the connecting flues routing the flue gas to the SCR system (see Figure 2). The existing flues between the boiler outlet and the air heaters are to be replaced with flue bends to direct the flue gas up to the reactor inlet and direct it to the air heater inlet. No dampers or bypass system are required since this is a natural-gas-fired application and low-NO_x emissions are required year long for all modes of operation. Major reasons for selecting this arrangement include flexibility in operation, minimum effects on current operation, and compatibility with the controls system upgrade.

Draft Requirements

This new SCR arrangement results in significant changes to system draft requirements due to the catalyst, additional flues, and changes in operation. The addition of gas recirculation, low-NO_x burners, and other boiler modifications over the operating life of these units nearly consumed the original design draft margins. After review of various alternatives the decision was made to add ID fans in the flues between the air heaters and stack and to upgrade the FD fans as part of this SCR addition. The new design resulted in the air- and gas-side design pressures being exceeded. The boilers, flues, and ducts being replaced require reinforcement to meet new pressure design limits per NFPA.

Equipment Description

The turnkey scope of supply for the SCR system includes the reactor module and internals; catalyst; the connecting flues; support steel; foundations; aqueous ammonia storage, delivery, control, and injection; controls and instrumentation; electrical equipment; wiring; piping; safety equipment; insulation and lagging; flow model study; FD and ID fans; boiler reinforcement; engineering; project management; installation; startup; and testing.

While most of this equipment and activities are typical and routine for a gas-fired SCR retrofit system, there are a few unique items that have been included to address specific plant concerns and issues. Due to concerns for particulate emissions after boiler outages and boiler water washes, the selected material for the new flues and reactor casing is stainless steel, SS 409.

Catalyst

The SCR catalyst is engineered and manufactured by Cormetech, Inc. The catalyst is a homogeneous extrudate with pitch optimized at 3.7 mm for low pressure drop. Catalyst chemistry is Titania-Vanadia-Tungsten and is compatible with both natural gas and oil firing. Experience is substantial for this specified catalyst; California hosts ten (10) reference plants with installations beginning in 1993 and each of these boilers have exceeded performance guarantees and expectations. All of these boilers continue to perform reliably with the original catalyst bed installed.

The catalyst bed is constructed in a single layer of carbon steel modules. Flue gas flow through the catalyst is in a vertical downward path. The flue gas mixes with the reagent prior to entering the catalyst bed and a single pass through the bed removes the required NO_x at minimal slippage of ammonia. For life extension, the catalyst modules are custom designed to accommodate stacking for the future addition of a second catalyst layer. This module construction allows flexibility in reactor management without the necessity of building a second independently supported internal framework. Catalysts for Units 6 and 7 are identical and interchangeable. (See Exhibit 2.)

Performance reliability is the most important goal of the SCR system. Performance warranties cover the entire operating range of these facilities, from 50 MW through full load. This turndown capability, with SCR operation, is an important factor in the economics of Moss Landing Power Plant. The catalyst selected has strong catalytic capability at the lowest operating flue gas temperatures and remains thermally stable through all operating conditions. NO_x removal is warranted for six years at approximately 90% removal efficiency, with ammonia slip no

more than 10 ppm throughout this warranted life. The catalyst warranty and bed design have been engineered for lowest lifecycle cost over the remaining economic life of Moss Landing.

A very important factor in the achievement and maintenance of such high performance is B&W's success in meeting the stringent requirements of ammonia/NO_x mixing. In addition to the controllable ammonia injection grid, Moss Landing Power Plant will have a permanent testing grid installed at the exit of the catalyst bed. The grid is used at startup for optimized reagent balancing and throughout the operating life of the SCR for any adjustments that may be beneficial. In a high performance SCR, good mixing is the essential factor in realizing the full catalytic potential of the SCR catalyst bed. The Moss Landing catalyst will be annually monitored and verified as to its capability through inspections and laboratory audits.

Flow Modeling

Cormetech and B&W are verifying all critical design elements in a scaled cold flow model. The cold flow model is being implemented by FERCO under the direction of Cormetech. (See Figure 3.)

The model is a three-dimensional scale model of the system based on B&W's General Arrangement drawings. The model extends from the back-pass dampers at the economizer outlet through the air preheater inlet, including APH pressure loss simulation. The flow model testing is based on a 1/12 scale constructed from clear plexiglas, as much as practical, to allow visualization tests. SCR reactor internals are included in the flow model as deemed necessary by the modeler and subject to B&W and Cormetech review.

Objectives of the flow model tests are:

1. Determine the optimum type, number and location of flue gas correction devices in the ductwork, so that uniform gas flow conditions exist at the inlet and outlet of the SCR reactor, and through the inlet to the APH.
2. Determine the distribution of velocity at strategic locations throughout the model including but not limited to the ammonia injection grid inlet, SCR reactor inlet, SCR reactor outlet (below catalyst), and APH inlet.
3. Determine ammonia distribution at the SCR catalyst inlet. Ammonia distribution will be optimized via the model test apparatus to meet the design requirements. The model will have the ability to adjust NH₃/air flow per zone. NH₃ injection is modeled using a tracer gas.
4. Determine and minimize the pressure drop increase imposed on the boiler system draft by the SCR system and demonstrate that it does not exceed maximum allowance (without additional catalyst layer) under the 100% load condition.

The design verifications being modeled are:

- Flue gas flow distribution at AIG inlet and catalyst inlet.
- Reagent mixing via tracer gas with AIG design and distribution of reagent at catalyst face.
- Variable load impact to flow distribution resulting from flue gas biasing at the boiler outlet.

Ammonia Storage

The ammonia storage area is designed for five low-pressure storage tanks, each sized to hold 30,000 gallons of 29.4 % aqueous ammonia. This system is designed to supply ammonia for thirty days of operation. The storage tanks are ASME Section VIII horizontal pressure vessels designed for 50 psig. To minimize difficulty in permitting anhydrous ammonia, Duke Energy specified the use of aqueous ammonia. Currently only four tanks will be installed since the fifth tank is to supply future new generating units, independently. This storage system provides ammonia for both Units 6 and 7 and one tank for the two future combined-cycle plants.

Ammonia is delivered by rail car. The rail car unloading area is designed to unload any one of three cars without moving rail cars. The ammonia storage tanks are manifolded together and pumps located in the storage area convey the aqueous ammonia about 1500 ft to reach the ammonia flow control station at each boiler.

Ammonia Flow Control and Injection

Heated dilution air and the aqueous ammonia mix together inside the packed-bed vaporizer. The vaporizer is designed to maximize the surface contact between the aqueous ammonia and the heated dilution air by the use of several structured packing stages. Aqueous ammonia is injected into the top of the vaporizer and distributed across the packing material via an internal ring manifold. The hot air enters from the vaporizer top and vaporizes the aqueous ammonia as it flows by gravity down through the packing. A pressure transmitter and a thermocouple are located at the discharge of the vaporizer. The full load design temperature is 180F and increases as load decreases.

The ammonia/air/water mixture leaves the vaporizers and is routed to the Manifold Valve Station (MVS) and delivered to the 12-zone Ammonia Injection Grid (AIG) supply headers per flue. Each supply header contains a manual throttling valve and flow orifice where a differential pressure gauge adjusts the ammonia flow to each injection grid. The flow control system is initially adjusted to provide a uniform ammonia mixture distribution. During commissioning, the flows to each feed pipe may be adjusted to optimize the NH₃ to NO_x distribution in the

flue gas. The manual throttle valves are set up using the NO_x distribution values obtained from the sampling grid traversing the lower portion of the reactor.

Project Organization and Integrated Comprehensive Schedule

To comply with Rule 431 of the Monterey Bay Unified Air Pollution Control District, one unit must be at 10 ppm maximum NO_x with less than 10 ppm slip after December 31, 2000 and the second unit in compliance after December 31, 2001. The project outage to install the SCR for Unit 6 is scheduled for the fall of 2000 as an extended outage is also planned for a major steam turbine overhaul. Unit 7 outage will occur later in 2001.

The plant asked if there would be any saving on installation cost if Unit 7 outage was moved to the spring of 2001. B&W provide savings due to lower field labor rates.

Summary

The SCR retrofit (See Figure 4) is required to meet NO_x emission of 10 ppm with NH₃ slip of less than 10 ppm per MBUAPD Rule 431 for Units 6 and 7 at Moss Landing Power Plant. The engineering study done in a interactive mode between B&W and Duke Energy allowed for discussion of operating issues and design questions as the scope was developed for the final design. These included selecting equipment for fast load response, minimizing heat rate penalties, and maintenance concerns. DENA told B&W up front they would purchase the catalyst and asked B&W to technically manage the Cormetech purchase order for the catalyst and flow model work.

Performance warranties cover the entire operating range of these facilities, from 50MW_e through 100% load. This turndown capability, with SCR operation, is an important factor in the economics of Moss Landing.

The catalyst selected for DENA has strong catalytic capability at the lowest operating flue gas temperatures and remains thermally stable through all operating conditions. NO_x removal is warranted for six years at approximately 90% removal efficiency, with ammonia slip no more than 10 ppm throughout this warranted life. The catalyst warranty and bed design has been engineered for lowest lifecycle cost over the remaining economic life of the plant.

Outage work coordination will be a critical item during the spring and summer months. Critical issues are storage area for each contractor's material, pre-outage assemble area, access between storage, and work areas. B&W Construction personnel manned the site with a part-time superintendent in February 2000 to support the plant outage manager in developing the overall outage schedule.