# Appendix G National Park Service Facility-specific Comment Summary Documents

**(From Don Shepherd)**

**ARD comments on the**
**Northwest Pulp & Paper Association**
**REGIONAL HAZE RULE FOUR-FACTORANALYSIS FOR FOUR OREGON PULP AND PAPER MILLS**
**June 2020 Report**

All4 prepared a report for the Northwest Pulp & Paper Association (NWPPA) and concluded that no additional controls were cost-effective for any pollutant at any of the mills it evaluated. We have several concerns with this report as it pertains to $NO_X$ controls and have noted our concerns in the following excerpts from the All4 report.

**$NO_X$ Economic Impacts**

LNB and FGR for Boiler $NO_X$ Control

The capital cost of implementing LNB and FGR to reduce $NO_X$ from each gas-fired industrial boiler without LNB is based on the document titled "Emission Control Study – Technology Cost Estimates" by BE&K Engineering for the American Forest and Paper Association (AF&PA), September 2001. Section 4.4 presents the costs associated with installing LNB, FGR, and a new fan on a 120,000 pounds of steam per hour (approximately 150 million British thermal units per hour [MMBtu/hr] heat input) natural gas-fired boiler. The direct capital cost (equipment and installation) was scaled from 2001 dollars to 2019 dollars using the CEPCI. The base capital cost was also scaled to each mill's boiler using an engineering cost scaling factor of 0.6 and the ratio of each mill's boiler heat input to the boiler heat input evaluated in the BE&K report. Table 2-4 summarizes the capital cost, annual cost, and cost effectiveness of implementing this control technology for the industrial boilers that do not already have LNB.

The effectiveness of installing LNB and FGR on each boiler is unknown and will depend on the current $NO_X$ emission rate. Where current NOx concentration data was not available, a 64% $NO_X$ reduction was assumed based on a comparison of AP-42 natural gas boiler pre-NSPS uncontrolled and LNB/FGR emission factors. Where current $NO_X$ concentration data were available and higher than 50 ppm, a control efficiency was calculated based on a reduction to 50 ppm.

SNCR for Boiler $NO_X$ Control

The cost of installing and operating an SNCR system on the natural gas-fired boilers was estimated using U.S. EPA's "Air Pollution Control Cost Estimation Spreadsheet for Selective Non-Catalytic Reduction (SNCR)" (June 2019) that reflects calculation methodologies presented in the U.S. EPA's Air Pollution Control Cost Manual, Section 4, Chapter 1. The spreadsheet estimates capital and annualized costs of installing and operating an SNCR based on site-specific data entered, such as boiler design and operating data. As the cost algorithms were developed based on project costs for large coal-fired utility boilers, they likely underestimate costs for smaller industrial boilers as costs for large utility boilers where this technology is routinely installed may not scale to smaller, variable load industrial boilers. The equipment cost was scaled to 2019 dollars using the CEPCI.

The U.S. EPA's cost manual allows a retrofit factor of greater than one where justification is provided. A retrofit factor of 1.5 was applied to account for the need to add multiple levels of injectors and perform additional tuning of the system across loads. The OAQPS Cost Manual (Section 4, Chapter 1) indicates that difficult installation conditions are often encountered for small boilers, and the boilers evaluated in this report are much smaller than coal-fired utility boilers.

SNCR control efficiencies vary widely, but urea-based systems typically achieve reductions from 37 to 60 percent on industrial boilers, according to the OAQPS Control Cost Manual. However, operating constraints on temperature, load, reaction time, and mixing often lead to less effective results when using SNCR in practice. Our analyses assume that SNCR would achieve 45% control on the boilers because pulp and paper mill boilers are subject to regular load swings. This control efficiency is supported by the range provided in the OAQPS Cost Manual and information publicly available from vendors. A formal engineering analysis would be required to ultimately determine if SNCR would be effective on the boilers. This type of analysis would include obtaining temperature and flow data, developing a model of each boiler using computational fluid dynamics, determining residence time and degree of mixing, determining placement of injectors, and testing.

SCR for Boiler $NO_X$ Control

The cost of installing and operating SCR system on each of the boilers was estimated using U.S. EPA's "Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction (SCR)" (June 2019) that reflects calculation methodologies presented in the U.S. EPA's Air Pollution Control Cost Manual, Section 4, Chapter 2. The spreadsheet estimates capital and annualized costs of installing and operating an SCR system based on site specific data entered, such as boiler design and operating data. As the cost algorithms were developed based on project costs for large coal-fired utility boilers, they likely underestimate costs for smaller industrial boilers as costs for large utility boilers where this technology is routinely installed may not scale to smaller, variable load industrial boilers.

The U.S. EPA's cost manual allows a retrofit factor of greater than one where justification is provided. A retrofit factor of 1.5 was applied since the EPA cost equations were developed based on utility boiler applications and to account for space constraints, additional ductwork, installation of a small duct burner to reheat the exhaust gas to the required temperature range, and the likelihood of needing a new ID fan to account for increased pressure drop. The equipment cost was scaled to 2019 dollars using the CEPCI. We assumed the SCR would achieve 90% control with installation of a duct burner to reheat the stack gas to 650 °F.

**NPS Air Resources Division (ARD) Comments**

**Technical Feasibility of SCR on Wood-fired Boilers**

The excerpt below is from the New Hampshire draft Regional Haze SIP:

> **Burgess BioPower**: The biomass unit at this facility was subject to NNSR for NOx at the time of their initial permitting; hence, the NOx limit was established as the LAER[1] based

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[1] A June 2018 review of the USEPA RBLC for biomass fired boilers greater than or equal to 250 MMBtu/hr indicates that 0.060 lb/MMBtu remains as LAER for NOx. While two recent determinations for similar facilities in

> limit. The NOx limit currently contained in the PSD/NNSR Permit TP-0054 is 0.060 lbs NOx/MMBtu on a 30-day rolling average, based on the use of SCR technology. Burgess BioPower uses clean wood as their fuel during normal operations and ULSD during plant startups. Both fuels are inherently very low in sulfur. The Burgess BioPower facility was also subject to PSD review for $SO_2$ at the time of its initial permitting in 2010; hence, the $SO_2$ limit in their current PSD/NNSR Permit TP-0052 of 0.012 lbs. $SO_2$/MMBtu was established as a BACT based limit. A June 2018 review of the USEPA RBLC for biomass fired EGUs greater than or equal to 25 MW indicates that low sulfur fuels remains the $SO_2$ BACT. Sorbent injection was installed for acid gas control but is not used to control $SO_2$ emissions because the emissions from burning wood are inherently very low (typically around 0.001 lbs $SO_2$/MMBtu). Monitoring data at the facility has shown that operation of the sorbent injection is not necessary to comply with the emission limit for $SO_2$. For this reason, NHDES has determined that the current limits for the above facilities represent the "most effective use of control technologies" for NOx and $SO_2$. Low-sulfur fuels and SCR are required by TP-0054 during year-round operations.

**Retrofit Factor**

All4 assumed a retrofit factor of 1.5 for every paper mill boiler it evaluated in Oregon, with this rationale:

> The U.S. EPA's cost manual allows a retrofit factor of greater than one where justification is provided. A retrofit factor of 1.5 was applied since the EPA cost equations were developed based on utility boiler applications and to account for space constraints, additional ductwork, installation of a small duct burner to reheat the exhaust gas to the required temperature range, and the likelihood of needing a new ID fan to account for increased pressure drop. The equipment cost was scaled to 2019 dollars using the CEPCI. We assumed the SCR would achieve 90% control with installation of a duct burner to reheat the stack gas to 650 °F.

When a retrofit factor greater than 1.0 is entered into the "Data Inputs" spreadsheet in EPA Control Cost Manual (CCM) workbooks, this notice appears: "* NOTE: You must document why a retrofit factor of (>1.0) is appropriate for the proposed project." The EPA Control Cost Manual (CCM) addresses "Retrofit Cost Considerations" in section 2.6.4.2 and recommends that site-specific retrofit factors (greater than the 1.0 default value) should be based upon a thorough and well-documented analysis of the individual factors involved in a project. For example, the methods outlined by William Vatavuk on pages 59-62 in his book Estimating Costs of Air Pollution Control be followed. That process involves estimating and assigning a retrofit factor to each major element of a project and from that deriving an overall retrofit factor. In the absence of such a proper analysis, assume a retrofit factor = 1.0, which represents a 30% increase above costs for a "greenfield" project. The All4 blanket application of the maximum retrofit factor falls short of the justification and documentation required by the CCM and EPA policy.

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Vermont established emission rates as low as 0.030 lb/MMBtu on a 12-month rolling period, NHDES understands that these rates have yet to be confirmed. The associated short term limits for these two facilities are 0.060 lb/MMBtu.

**Interest Rate**
All4 used a 4.75% interest rate instead of the current bank prime rate = 3.25% as recommended by the CCM.

**Operating Costs**
All4 overestimated the operating costs of SCR (and SNCR) when it substituted values for "Total operating time for the SCR ($t_{op}$)" and "Total NOx removed per year" for the values calculated by the CCM "Design Parameters" spreadsheets. We participated in the EPA work group that developed the CCM workbooks for $NO_X$ (and $SO_2$) controls and can advise that it is not appropriate to alter values in the "Design Parameters" spreadsheet because these values should, instead, be generated from the "Data Inputs" spreadsheet and the algorithms that operate on them according to the methods and equations described in the CCM.

The "Total operating time for the SCR ($t_{op}$)" parameter is not meant to be the actual operating time for the control device, which All4 entered directly into the "Design Parameters" spreadsheet. Instead, it represents a method to adjust capacity utilization to actual (or permitted) utilization based upon a fraction (Total System Capacity Factor ($CF_{total}$)) applied to the maximum capacity. (The spreadsheet assumes that the boiler is operating at maximum capacity for the hours calculated by $t_{op}$.) All4 compounded its error by also overriding the calculation of Total NOx removed per year to reflect percent removed from the PSEL or actual conditions instead of percent removed from the emissions that would have resulted from All4's hours of operation.

The basic parameters (on the "Data Inputs" spreadsheet) that define emissions and control costs are:

- maximum heat input rate (QB)
- higher heating value (HHV) of the fuel
- estimated actual annual fuel consumption
- net plant heat input rate (NPHR)
- Number of days the SCR (or SNCR) operates ($t_{SCR}$ or $t_{SNCR}$)
- Number of days the boiler operates ($t_{plant}$)
- Inlet NOx Emissions ($NO_{Xin}$) to SCR (or SNCR)
- Outlet NOx Emissions ($NO_{Xout}$) from SCR (or SNCR)

All but "estimated actual annual fuel consumption" are essentially fixed by the boiler, fuel, and control device characteristics. The "Number of days the SCR operates (tSCR)" typically equals "Number of days the boiler operates (tplant)."[2] We adjusted "estimated actual annual fuel consumption" to yield the uncontrolled emissions specified by All4.

All4 also overestimated reagent costs by more than an order of magnitude with no justification, and included costs for reheating the SCR inlet gas stream with no explanation of how this cost was derived. (All4's fuel cost is higher than the current EIA estimate.)

All4 included property taxes in several analyses. It is our understanding that Oregon allows exemptions from property taxes for air pollution control equipment.

[2] In March 2021, EPA revised the SNCR workbook to include an entry for the "Number of days the boiler operates (tplant)." Until that revision, the SNCR workbook assumed 365 days of plant operation.

We are using the SCR and SNCR workbooks developed by EPA for its CCM to address the problems described above and will be sending them to OR DEQ soon. We will show that the costs of achieving significant $NO_X$ reductions at Oregon's pulp & paper mills are significantly lower than submitted by the NWPPA.

**Georgia-Pacific**
**Toledo LLC**
**July 30, 2021**

**Excerpts from the company submittal dated June 2020**

**Power Boilers**
The Georgia-Pacific-Toledo (GPT) Mill is permitted to fire fuel oil in the No. 1 Power Boiler, but only fires natural gas, resulting in lower $PM_{10}$ and $SO_2$ emissions. The Mill is permitted to fire hog fuel and old corrugated container (OCC) rejects in the No. 4 Power Boiler, but only fires natural gas, resulting in lower $NO_X$, $PM_{10}$, and $SO_2$ emissions.

$PM_{10}$ Emissions
The four boilers at the GP Toledo Mill burn only natural gas and have minimal $PM_{10}$ emissions. No $PM_{10}$ controls beyond burning natural gas are feasible for these boilers.

$NO_X$ Economic Impacts
The GP Toledo No. 5 Power Boiler already uses LNB and FGR to reduce $NO_X$ emissions.

**Lime Kiln**
$PM_{10}$ Emissions
GP Toledo utilizes wet scrubbers for PM control on its lime kilns.

$SO_2$ Emissions
The lime kilns provide inherent control of $SO_2$ through absorption of sulfur by the calcium in the kiln. The mill fires natural gas as the primary fuel in its lime kilns, which minimizes $SO_2$ emissions, particularly during startup and shutdown. The lime kilns are equipped with wet scrubbers, primarily for reduction of PM and TRS emissions. Actual lime kiln $SO_2$ emissions at the GP Toledo mill are less than 1 tpy, so no additional $SO_2$ controls are necessary for these kilns.

**PAPER MACHINES AND PULP DRYERS**
Paper machines and pulp dryers consist of the wet end and the dry end and the combined equipment can be the length of a football field and have many different exhaust points through roof vents or building exhausts. On the wet end, pulp is combined with additives and diluted with water at the head box, applied to the former or wire, where it forms a sheet as the water drains, and then travels to the press and dryer sections (dry end) to remove the remaining water. The paper machines at GP Toledo are steam heated and do not have emissions of $NO_X$ or $SO_2$.

**OR DEQ**
In a letter dated January 21, 2021, DEQ notified Georgia Pacific of its preliminary determination that their Toledo facility would likely be required to install control devices on several of its emissions units, as shown in Table 3-46. Cost effectiveness of adding a baghouse to EU-118 may be revised after the results of upcoming source testing.

Table 0 1: Control devices likely required Georgia-Pacific, Toledo

| Emissions Unit | Control Device | Target Pollutant |
|---|---|---|
| EU-118 Hardwood Chip handling | Baghouse | $PM_{10}$ |
| EU-1 Lime Kiln | LNB | $NO_x$ |
| EU-2 Lime Kilns | LNB | $NO_x$ |
| EU-3 Lime Kiln | LNB | $NO_x$ |
| EU-11 No. 4 Boiler | SCR | $NO_x$ |
| EU-13 No. 1 Boiler | SCR | $NO_x$ |
| EU-18 No. 3 Boiler | SNCR | $NO_x$ |

**ARD Comments**

GP and its consultant (All4) have overestimated capital and operating costs of applying SCR to the Power Boiler and the Package Boiler. All4 overestimated capital costs when it assumed a retrofit factor of 1.5 without the justification and documentation required by the CCM and EPA policy.

All4 also overestimated the operating costs of SCR when it substituted values for "Total operating time for the SCR ($t_{op}$)" and "Total NOx removed per year" for the values calculated by the CCM "Design Parameters" spreadsheets. For example, for the Power Boiler #3 (PSEL), All4's workbook correctly calculated the Total System Capacity Factor = 0.984 but over-rode that result by entering 8760 hours for Total operating time for the SCR instead of the value of 8620 hours that would have been calculated by the spreadsheet. All4 then allowed the workbook to calculate annual operating costs as if the SCR were operating at maximum capacity 8760 hours instead of 8620 hours. All4 compounded its error by also over-riding the calculation of Total NOx removed per year to reflect 90% removed from the PSEL (90% * 107.6 tpy) instead of 90% removed from the emissions (98.4 tpy) that would have resulted from All4's 8760 hours of operation (90% * 98.4 tpy). Instead, we adjusted "estimated actual annual fuel consumption" to yield the uncontrolled emissions specified by All4.

All4's resulting Total Annual Cost of $1.3 million for the Power Boiler #3 contains several overestimated cost components. The capital cost was escalated by 50% due to the application of an unjustified retrofit factor. (All4 also used a 4.75% interest rate instead of the current bank prime rate = 3.25% as recommended by the CCM.) Operating costs were overestimated due to overriding of the "Total operating time" parameter. All4 also overestimated reagent costs by more than an order of magnitude with no justification, and included costs for reheating the SCR inlet gas stream with no explanation of how this cost was derived. (All4's fuel cost of $5.00/mmBtu exceeds the approximately $4.00/mmBtu Oregon industrial price for natural gas according to the EIA. [3]) Instead of All4's estimated cost-effectiveness = $13,579/ton, we estimate a Total Annual Cost of $1.2 million = $12,446/ton for addition of SCR to remove 97 ton/yr of $NO_X$. (Even though there was no justification provided for the reheat fuel use rate, we accepted All4's estimate to estimate reheat cost—please see the attached workbooks.) The cost effectiveness of adding SCR for Power Boiler #3 also exceeds the OR DEQ threshold under

[3] Oregon Natural Gas Industrial Price (Dollars per Thousand Cubic Feet) (eia.gov)

actual conditions, but that result is highly dependent upon the cost of reheating the SCR inlet gas stream and should be verified.

The same issues apply to Power Boiler #1 and the Hogged Fuel Boiler #4. We applied the SCR CCM workbook to these boilers for both the PSEL and actual conditions and the cost-effectiveness of adding SCR fall below the OR DEQ threshold of $10,000/ton for Power Boiler #1 and the Hogged Fuel Boiler #4.

| **SCR** | Company/Consultant Estimates | | NPS Air Resources Division Estimates | |
|---|---|---|---|---|
| Unit | #3 Pwr Blr (PSEL) | #3 Pwr Blr (actuals) | #3 Pwr Blr (PSEL) | #3 Pwr Blr (actuals) |
| Emissions Reduction (tpy) | 97 | 68 | 97 | 68 |
| Total Annual Cost | $ 1,314,983 | $ 1,296,647 | $ 1,203,346 | $ 916,698 |
| Cost-Effectiveness ($/ton) | $ 13,579 | $ 19,057 | $ 12,446 | $ 13,465 |

| **SCR** | Company/Consultant Estimates | | NPS ARD Estimates | |
|---|---|---|---|---|
| Unit | #1 Pwr Blr (PSEL) | #1 Pwr Blr (actuals) | #1 Pwr Blr (PSEL) | #1 Pwr Blr (actuals) |
| Emissions Reduction (tpy) | 201 | 135 | 200 | 135 |
| Total Annual Cost | $ 1,736,111 | $ 1,713,128 | $ 1,279,086 | $ 949,489 |
| Cost-Effectiveness ($/ton) | $ 8,623 | $ 12,681 | $ 6,386 | $ 7,014 |

| **SCR** | **Company/Consultant Estimates** | | **NPS Air Resources Division Estimates** | |
|---|---|---|---|---|
| Unit | #4 Hog Fuel Blr (PSEL) | #4 Hog Fuel Blr (actuals) | #4 Hog Fuel Blr (PSEL) | #4 Hog Fuel Blr (actuals) |
| Emissions Reduction (tpy) | 197 | 190 | 197 | 190 |
| Retrofit factor | 1.5 | 1.5 | 1 | 1 |
| Total Annual Cost | $ 2,175,317 | $ 2,307,306 | $ 1,429,189 | $ 1,023,762 |
| Cost-Effectiveness ($/ton) | $ 11,067 | $ 12,173 | $ 7,262 | $ 5,374 |

Power Boiler #3 SNCR

Because OR DEQ proposed that SNCR be applied to Power Boiler #3 instead of SCR, we evaluated both the PSEL and actual emissions scenarios for this boiler. All4 overestimated costs for the following reasons:

- A retrofit factor of 1.5 was applied with no justification.
- The interest rate was too high (4.75% versus 3.25%).
- The $5.00/mmBtu fuel cost was not justified (versus the approximately $4.00/mmBtu current industrial cost of natural gas in Oregon according to the EIA).
- All actual operating costs were overestimated because All4 overrode/overestimated the "Total operating time for the SNCR" parameter (8531 hrs versus 5902 hrs).

Our corrected estimates are shown below.

| **SNCR** | Company/Consultant Estimates | | NPS Air Resources Division Estimates | |
|---|---|---|---|---|
| Unit | #3 Pwr Blr (PSEL) | #3 Pwr Blr (actuals) | #3 Pwr Blr (PSEL) | #3 Pwr Blr (actuals) |
| Emissions Reduction (tpy) | 48 | 34 | 48 | 34 |
| Total Annual Cost | $ 414,919 | $ 412,543 | $ 307,576 | $ 259,637 |
| Cost-Effectiveness ($/ton) | $ 8,569 | $ 12,126 | $ 6,362 | $ 7,607 |

**Results & Conclusions**

- Addition of SCR to Power Boilers #1 and Hogged Fuel Boiler #4 is much less expensive than estimated by Georgia-Pacific and its cost-effectiveness would not exceed the OR DEQ threshold under PSEL operating conditions.
- Addition of SCR to Power Boiler #1 and Hogged Fuel Boiler #4 is much less expensive than estimated by Georgia-Pacific and its cost-effectiveness would not exceed the OR DEQ threshold under actual operating conditions.
- Addition of SCR to Power Boiler #3 is much less expensive than estimated by Georgia-Pacific and its cost-effectiveness relative to the OR DEQ threshold under PSEL and actual operating conditions is highly dependent upon costs to reheat the SCR inlet gas stream; this should be investigated further.
- Addition of SCR to these three boilers could reduce $NO_X$ emissions by 494 tons/yr under PSEL conditions or 393 tons/yr under actual conditions.
- Addition of SNCR to Power Boiler #3 is much less expensive than estimated by Georgia-Pacific and its cost-effectiveness would not exceed the OR DEQ threshold under PSEL or actual operating conditions.

**Georgia Pacific**
**Wauna Mill**
**July 1, 2021**

**Excerpts from the company submittal dated June 2020**

**Power Boilers**

**$SO_2$ Emissions**
The GP Wauna Fluidized Bed Boiler already has limestone addition to the fluidized bed. No further $SO_2$ emissions controls are feasible for the GP boilers that burn only natural gas.

**PM10 Emissions**
The Power Boiler at the GP Wauna Mill burns only natural gas and has minimal $PM_{10}$ emissions. No $PM_{10}$ controls beyond burning natural gas are feasible for this boiler. The GP Wauna Mill's biomass-fired Fluidized Bed Boiler is controlled by a fabric filter, is subject to a filterable PM emission limit of 0.01 grain per dry standard cubic foot (gr/dscf), and complies with both New Source Performance Standards (NSPS, Subpart Db) and Boiler MACT. Based on a review of similar units in the RBLC, this unit is already well controlled for $PM_{10}$.

**$PM_{10}$ Economic Impacts**
For purposes of this report, and because the $PM_{10}$ PSEL for the GP Wauna Fluidized Bed Boiler is 62.4 tpy, a cursory evaluation of whether adding a polishing WESP to that unit to reduce $PM_{10}$ emissions further would be cost effective was performed. Based on U.S. EPA's fact sheet for WESPs, in 2002 dollars, the capital cost ranges from $40 to $200 per standard cubic foot per minute (scfm) exhaust flow rate and the annual cost ranges from $12 to $46 per scfm. Based on the low end of these ranges and a flow rate of 55,000 scfm, a polishing WESP would require an investment of at least $2.2 million in capital cost and $660,000 per year in annual cost. While achieving an additional 99% reduction of $PM_{10}$ emissions from the outlet stream of an already well controlled source utilizing a baghouse is highly unlikely, even if a polishing WESP achieved a 99 percent reduction in the 62.4-tpy $PM_{10}$ PSEL, the approximate cost would be $10,684/ton of $PM_{10}$ removed, which is not cost effective.

**$SO_2$ Economic Impacts**
The capital cost for a system to inject milled trona prior to the fabric filter on the GP Wauna Fluidized Bed Boiler was estimated using an April 2017 Sargent and Lundy report prepared under a U.S. EPA contract. Industry standard labor, chemical, and utility costs were used to estimate the annual cost of operating the system. The Sargent and Lundy report indicates that 90% $SO_2$ control can be achieved when injecting trona prior to a fabric filter.

**Recovery Furnace**
The Georgia Pacific (GP) Wauna Mill is permitted to fire fuel oil in the recovery furnace, but only fires natural gas as auxiliary fuel, resulting in lower $PM_{10}$ and $SO_2$ emissions.

**Lime Kiln**

The Georgia Pacific (GP) Wauna Mill is permitted to fire fuel oil in the lime kiln, but only fires natural gas as auxiliary fuel, resulting in lower $PM_{10}$ and $SO_2$ emissions.

**PM10 Emissions**

GP Wauna utilizes wet scrubbers for PM control on its lime kiln. An ESP prior to the wet scrubber would provide additional $PM_{10}$ control and is considered technically feasible.

**$SO_2$ Emissions**

The lime kiln provides inherent control of $SO_2$ through absorption of sulfur by the calcium in the kiln. The mill fires natural gas as the primary fuel in its lime kiln, which minimizes $SO_2$ emissions, particularly during startup and shutdown. The portion of the $SO_2$ PSEL assigned to the lime kiln at GP Wauna is less than 5 tpy, so no additional $SO_2$ controls are necessary for this kiln.

**Towel & Tissue Machines**

GP Wauna's towel and tissue machines include fuel burning sources and wet controls to limit $PM_{10}$ emissions. Tissue machines are configured differently than traditional paper machines and pulp dryers and their PM emissions are higher in most cases. GP Wauna has performed an evaluation of whether additional controls are feasible and is submitting the evaluation as an attachment to their cover letter transmitting this report.

**OR DEQ**

In a letter dated January 21, 2021, DEQ notified Georgia Pacific of its preliminary determination that their Wauna facility would likely be required to install control devices on several of its emissions units, as shown in Table 3-44, including Low $NO_x$ Burners and SCR. Discussions with the facility are ongoing.

Table 0 2: Control devices likely required Georgia Pacific – Wauna Mill.

| Emissions Unit | Control Device | Target Pollutant |
|---|---|---|
| Paper Machine 1: Yankee Burner | LNB | $NO_x$ |
| Paper Machine 2: Yankee Burner | LNB | $NO_x$ |
| Paper Machine 5: Yankee Burner | LNB | $NO_x$ |
| 21 - Lime Kiln | LNB | $NO_x$ |
| Paper Machine 6: TAD1 Burners | LNB | $NO_x$ |
| Paper Machine 7: TAD1 Burners | LNB | $NO_x$ |
| Paper Machine 6: TAD2 Burners | LNB | $NO_x$ |
| Paper Machine 7: TAD2 Burners | LNB | $NO_x$ |
| 33 - Power Boiler | SCR | $NO_x$ |

**ARD Comments**

GP and its consultant (All4) have overestimated capital and operating costs of applying SCR to the Power Boiler and the Fluidized Bed Boiler. All4 overestimated capital costs when it assumed a retrofit factor of 1.5 without the justification and documentation required by the CCM and EPA policy.

All4 also overestimated the operating costs of SCR when it substituted values for "Total operating time for the SCR ($t_{op}$)" and "Total NOx removed per year" for the values calculated by the CCM "Design Parameters" spreadsheets. For example, for the Fluidized Bed Boiler (PSEL), All4's workbook correctly calculated the Total System Capacity Factor = 0.833 but over-rode that result by entering 8760 hours for Total operating time for the SCR instead of the value of 7297 hours that would have been calculated by the spreadsheet. All4 then allowed the workbook to calculate annual operating costs as if the SCR were operating at maximum capacity 8760 hours instead of 7297 hours. All4 compounded its error by also over-riding the calculation of Total NOx removed per year to reflect 90% removed from the PSEL (90% * 224.4 tpy) instead of 90% removed from the emissions (242.3 tpy) that would have resulted from All4's 8760 hours of operation (90% * 242.3 tpy). Instead, we adjusted "estimated actual annual fuel consumption" to yield the uncontrolled emissions specified by All4.

All4's resulting Total Annual Cost of $3 million for the Fluidized Bed Boiler contains several overestimated cost components. The capital cost was escalated by 50% due to the application of an unjustified retrofit factor. (All4 also used a 4.75% interest rate instead of the current bank prime rate = 3.25% as recommended by the CCM.) Operating costs were overestimated due to over-riding of the Total operating time parameter. All4 also overestimated reagent costs by more than an order of magnitude with no justification, and included costs for reheating the SCR inlet gas stream with no explanation of how this cost was derived. (All4's fuel cost is 25% higher than the current Oregon industrial natural gas price.[4]) Instead of All4's estimated cost-effectiveness = $15,069/ton, we estimate a Total Annual Cost of $1.8 million = $8775/ton for addition of SCR to remove 202 ton/yr of $NO_X$. (Even though there was no justification provided for the reheat fuel use rate, we accepted All4's estimate to estimate reheat cost—please see the attached workbooks.)

| **SCR** | **Company/Consultant Estimates** | | **NPS ARD Estimates** | |
|---|---|---|---|---|
| Unit | FBB (PSEL) | FBB (actual) | FBB (PSEL) | FBB (actual) |
| Emissions Reduction (tpy) | 202 | 153 | 202 | 155 |
| Total Annual Cost | $ 3,043,381 | $ 3,222,435 | $ 1,770,437 | $ 1,327,408 |
| Cost-Effectiveness ($/ton) | $ 15,069 | $ 21,000 | $ 8,775 | $ 8,590 |

The same issues apply to Fluidized Bed Boiler at actual conditions as well as the Power Boiler at PSEL and actual conditions. We applied the SCR CCM workbook to these boilers for both the PSEL and actual conditions and the cost-effectiveness of adding SCR falls below the OR DEQ threshold of $10,000/ton for the PSEL and actual cases for both boilers.

[4] Oregon Natural Gas Industrial Price (Dollars per Thousand Cubic Feet) (eia.gov)

| **SCR** | **Company/Consultant Estimates** | | **NPS ARD Estimates** | |
|---|---|---|---|---|
| Unit | Pwr Blr (PSEL) | Pwr Blr (actual) | Pwr Blr (PSEL) | Pwr Blr (actual) |
| Emissions Reduction (tpy) | 532 | 239 | 530 | 240 |
| Total Annual Cost | $ 4,444,671 | $ 2,942,622 | $ 2,088,644 | $ 1,127,831 |
| Cost-Effectiveness ($/ton) | $ 8,353 | $ 12,317 | $ 3,939 | $ 4,709 |

## Results & Conclusions

- Addition of SCR to the Power Boiler and the Fluidized Bed Boiler is much less expensive than estimated by Georgia-Pacific and its cost-effectiveness would not exceed the OR DEQ threshold under PSEL or actual operating conditions.
- Addition of SCR to these two boilers could reduce $NO_X$ emissions by 732 tons/yr under PSEL conditions or 395 tons/yr under actual conditions.

## Boise Cascade Wood Products, LLC - Elgin Complex

**OR DEQ:** In a letter dated January 21, 2021, DEQ notified Boise Cascade Wood Products of its preliminary determination that their Elgin facility would likely be required to install Selective Catalytic Reduction on Boilers 1 and 2.

**Excerpts from Boise Cascade/All4's June 2020 report, "REGIONAL HAZE RULE FOUR FACTOR ANALYSIS FOR THE BOISE CASCADE WOOD PRODUCTS ELGIN PLYWOOD MILL"**

*SUMMARY OF RECENT EMISSIONS REDUCTIONS*

Since 2010, the Elgin Mill has made emissions reductions for a variety of reasons. Each of the biomass boilers is subject to the provisions of 40 CFR Part 63, Subpart DDDDD, NESHAP for Industrial Commercial, and Institutional Boilers and Process Heaters (NESHAP DDDDD or Boiler MACT). Boilers subject to NESHAP DDDDD were required to undergo a one-time energy assessment and are required to conduct tune-ups at a frequency specified by the rule. Compliance with these standards required changes to operating practices, including use of clean fuels for startup.

**FOUR FACTOR ANALYSIS FOR BOILERS**

This section of the report presents the results of a Four Factor analysis for $PM_{10}$, $SO_2$, and $NO_X$ emitted from the Elgin Mill biomass boilers. The two boilers are each 72 MMBtu/hr biomass wet stoker units and are controlled by a common dry electrostatic precipitator (ESP).

**Site Specific Factors Limiting Implementation**

Currently known, site-specific factors that would limit the feasibility and increase the cost of installing additional controls include space constraints. Note that a detailed engineering study for each of the controls evaluated in this report would be necessary before any additional controls were determined to be feasible or cost effective.

**Selective Catalytic Reduction (SCR)**

Although SCR was not identified in the RLBC search as a technology typically employed on biomass-fired industrial boilers, it has been applied to coal-fired utility boilers. The presence of alkali metals such as sodium and potassium, which are commonly found in wood, but not fossil fuels, will poison catalysts and the effects are irreversible. Other naturally occurring catalyst poisons found in wood are phosphorous and arsenic. Therefore, it is not feasible to place an SCR upstream of a particulate control device on a biomass boiler.

**PM10 Emissions**

Due to the typically lower $PM_{10}$ removal efficiencies than dry ESPs, and the generation of wastewater, this analysis does not consider the use of wet controls for $PM_{10}$ emissions control. Fabric filters are rarely implemented on wood-fired boilers due to risk of fire (any retrofit implementation would require a long stretch of ductwork between the economizer and the control device to reduce the risk of fire). ESPs are almost as efficient as the best fabric filters without the fire risk. ESPs can withstand higher temperatures, have a smaller footprint, use less energy, and have lower maintenance requirements and better separation efficiencies than fabric filters. Therefore, use of a fabric filter for $PM_{10}$ control was not considered feasible and was not evaluated. The Elgin Mill biomass boilers are already very well controlled and are subject to Boiler MACT emission limits and work practices.

**NOx Emissions**

$NO_X$ emissions from biomass boilers originate primarily from oxidation of fuel bound nitrogen. The Elgin Boilers are in the biomass wet stoker subcategory under the Boiler MACT rule. Biomass is fed to the boilers above the grate, begins to combust in suspension, and then completes combustion on the grate. Low-$NO_X$ burners and water injection are not applicable to this design. The air system is optimized during the required Boiler MACT tune-ups and FGR is not likely to provide a significant reduction in $NO_X$.

Add-on NOx controls such as SNCR and SCR require a specific temperature window to be effective. These controls were developed for and have predominantly been applied to fossil fuel fired boilers. There are challenges associated with applying SNCR to an industrial biomass boiler due to variability in boiler load. Good mixing of the reagent and NOx in the flue gas at the optimum temperature window is the key to achieving a NOx reduction for SCR and SNCR. In biomass boilers, this temperature window is a function of the variations in fuel quality and the load on the boiler. The temperature profile in a wood-fired industrial boiler is not as constant as that of a fossil fuel-fired utility boiler. Biomass boilers at forest products mills are often subject to highly variable swings in steaming rate, fuel flow, fuel mix, and bark moisture, depending on mill steam demand, availability of bark, amount of other fuels fired, and weather conditions.

The feasibility of SCR application to biomass boilers is also uncertain. This technology has been demonstrated mostly on large coal- and natural gas-fired combustion units in the utility industry.

In practice, SCR systems operate at NOx control efficiencies in the range of 70 to 90% for fossil fuel utility boilers. Optimum temperatures for the SCR process range from 480 to 800°F. Due to catalyst plugging and poisoning problems associated with locating the catalyst prior to the particulate control device , an SCR system would have to be installed after an existing particulate control device, and would likely require installation of a gas-fired flue gas re-heater to achieve the optimum reaction temperature (the flue gas temperature for biomass boilers is typically less than 480°F). This would incur associated fuel costs and pollution increases, running counter to the administration's goal to reduce greenhouse gases, assuming there is adequate space to install the size re-heater needed to raise the temperature of the exhaust gas stream to the optimum temperature of 600 °F. Despite these challenges, for purposes of this analysis, we evaluated cost effectiveness of an SCR achieving 90% control, but we incorporated a retrofit factor of 1.5 to account for the difficulty of applying SCR to a biomass boiler and the likely need to add ductwork and to replace the fan to overcome additional pressure drop through the system.

**Site Specific Factors Limiting Implementation**

Currently known, site-specific factors that would limit the feasibility and increase the cost of installing additional controls include space constraints. Note that a detailed engineering study for each of the controls evaluated in this report would be necessary before any additional controls were determined to be feasible or cost effective.

**$NO_X$ Economic Impacts**

This section describes the economic impacts associated with each NOx add-on control option evaluated for the boilers. Note that cost effectiveness was evaluated based on the PSEL, and the cost per ton would be even higher if evaluated based on actual emissions.

**SCR for Boiler $NO_X$ Control**

All4 applied a retrofit factor of 1.5 because the EPA cost equations were developed based on utility boiler applications and to account for space constraints, additional ductwork, the need for stack reheat, and the likelihood of needing a new induced draft fan to account for increased pressure drop.

The All4 cost analysis is based on the boilers' capacity and their $NO_X$ PSEL of 170 tpy, although actual emissions in 2017 were only 125.6 tpy. Installing an SCR is not considered cost effective because the capital cost is estimated at more than $15 million and the cost effectiveness values are well in excess of $3,400/ton of pollutant removed, the cost effectiveness threshold for non-EGUs used by EPA for similar studies.

*REMAINING USEFUL LIFE OF EXISTING AFFECTED SOURCES*

All4 assumed that the emissions units and controls included in this analysis have a remaining useful life of twenty years or more.

**NPS Air Resources Division (ARD) Analysis**

**Technical Feasibility of SCR on Wood-fired Boilers**

The excerpt below is from the New Hampshire draft Regional Haze SIP:

> **Burgess BioPower**: The biomass unit at this facility was subject to NNSR for NOx at the time of their initial permitting; hence, the NOx limit was established as the LAER[5] based limit. The NOx limit currently contained in the PSD/NNSR Permit TP-0054 is 0.060 lbs NOx/MMBtu on a 30-day rolling average, based on the use of SCR technology. Burgess BioPower uses clean wood as their fuel during normal operations and ULSD during plant startups. Both fuels are inherently very low in sulfur. The Burgess BioPower facility was also subject to PSD review for $SO_2$ at the time of its initial permitting in 2010; hence, the $SO_2$ limit in their current PSD/NNSR Permit TP-0052 of 0.012 lbs. $SO_2$/MMBtu was established as a BACT based limit. A June 2018 review of the USEPA RBLC for biomass fired EGUs greater than or equal to 25 MW indicates that low sulfur fuels remains the $SO_2$ BACT. Sorbent injection was installed for acid gas control but is not used to control $SO_2$ emissions because the emissions from burning wood are inherently very low (typically around 0.001 lbs $SO_2$/MMBtu). Monitoring data at the facility has shown that operation of the sorbent injection is not necessary to comply with the

[5] A June 2018 review of the USEPA RBLC for biomass fired boilers greater than or equal to 250 MMBtu/hr indicates that 0.060 lb/MMBtu remains as LAER for NOx. While two recent determinations for similar facilities in Vermont established emission rates as low as 0.030 lb/MMBtu on a 12-month rolling period, NHDES understands that these rates have yet to be confirmed. The associated short term limits for these two facilities are 0.060 lb/MMBtu.

> emission limit for $SO_2$. For this reason, NHDES has determined that the current limits for the above facilities represent the "most effective use of control technologies" for NOx and $SO_2$. Low-sulfur fuels and SCR are required by TP-0054 during year-round operations.

We have several concerns with the Boise Cascade analyses conducted by All4.

**Retrofit Factor**
All4 assumed a retrofit factor of 1.5 for every woodwaste boiler it evaluated in Oregon. The EPA Control Cost Manual (CCM) recommends that site-specific retrofit factors (greater than the 1.0 default value) should be based upon a thorough and well-documented analysis of the individual factors involved in a project. For example, the methods outlined by William Vatavuk on pages 59-62 in his book <u>Estimating Costs of Air Pollution Control</u> be followed. That process involves estimating and assigning a retrofit factor to each major element of a project and from that deriving an overall retrofit factor. The CCM also addresses "Retrofit Cost Considerations" in section 2.6.4.2. In the absence of such a proper analysis, assume a retrofit factor = 1.0, which represents a 30% increase above costs for a "greenfield" project. The All4 blanket application of the maximum retrofit factor falls short of the justification and documentation required by the CCM and EPA policy.

**SCR Equipment Life**
All4 assumed a 20-year life for these boilers; for all other woodwaste-fired boilers All4 evaluated in Oregon and Washington, All4 assumed 25-year life; we used the CCM default = 25 years.

**Chemical Engineering Plant Cost Index (CEPCI)**
All4 used a 2019 CEPCI = 603.1; the correct CEPCI = 607.5.

**Interest Rate**
All4 used a 4.75% interest rate instead of the current bank prime rate = 3.25% as recommended by the CCM.

**Operating Costs**
All4 overestimated the operating costs of SCR (and SNCR) when it substituted values for "Total operating time for the SCR ($t_{op}$)" and "Total NOx removed per year" for the values calculated by the CCM "Design Parameters" spreadsheets. We participated in the EPA work group that developed the CCM workbooks for $NO_X$ (and $SO_2$) controls and can advise that it is not appropriate to alter values in the "Design Parameters" spreadsheet because these values should, instead, be generated from the "Data Inputs" spreadsheet and the algorithms that operate on them according to the methods and equations described in the CCM.

The "Total operating time for the SCR ($t_{op}$)" parameter is not meant to be the actual operating time for the control device, which All4 entered directly into the "Design Parameters" spreadsheet. Instead, it represents a method to adjust capacity utilization to actual (or permitted) utilization based upon a fraction (Total System Capacity Factor ($CF_{total}$)) applied to the maximum capacity. All4 compounded its error by also over-riding the calculation of Total NOx removed per year to reflect percent removed from the PSEL or actual conditions instead of percent removed from the emissions that would have resulted from All4's hours of operation.

The basic parameters (on the "Data Inputs" spreadsheet) that define emissions and control costs are:

- maximum heat input rate (QB)
- higher heating value (HHV) of the fuel
- estimated actual annual fuel consumption
- net plant heat input rate (NPHR)
- Number of days the SCR (or SNCR) operates ($t_{SCR}$ or $t_{SNCR}$)
- Number of days the boiler operates ($t_{plant}$)
- Inlet NOx Emissions ($NO_{Xin}$) to SCR (or SNCR)
- Outlet NOx Emissions ($NO_{Xout}$) from SCR (or SNCR)

All but "estimated actual annual fuel consumption" are essentially fixed by the boiler, fuel, and control device characteristics. The "Number of days the SCR operates (tSCR)" typically equals "Number of days the boiler operates (tplant)."[6] We adjusted "estimated actual annual fuel consumption" to yield the uncontrolled emissions specified by All4.

For example, the "Total operating time for the SCR ($t_{op}$)" parameter is not meant to be the actual operating time for the control device. Instead, it represents a method to adjust capacity utilization to actual utilization based upon a fraction (Total System Capacity Factor ($CF_{total}$) applied to the maximum capacity. For the Power Boiler (PSEL), All4's workbook correctly calculated the Total System Capacity Factor = 0.976 but over-rode that result by entering 8760 hours for Total operating time for the SCR instead of the value of 8550 hours that would have been calculated by the spreadsheet. All4 then allowed the workbook to calculate annual operating costs as if the SCR were operating at maximum capacity 8760 hours instead of 8550 hours. All4 compounded its error by also overriding the calculation of Total NOx removed per year to reflect 90% removed from the PSEL (90% * 170 tpy) instead of 90% removed from the emissions (153 tpy) that would have resulted from All4's 8760 hours of operation (90% * 153 tpy).

All4 included property taxes in several analyses. It is our understanding that Oregon allows exemptions from property taxes for air pollution control equipment.

We applied the CCM workbook and adjusted the "estimated actual annual fuel consumption" to yield the uncontrolled emissions (170 ton/yr) specified by All4. Our results are shown below.

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[6] In March 2021, EPA revised the SNCR workbook to include an entry for the "Number of days the boiler operates (tplant)." Until that revision, the SNCR workbook assumed 365 days of plant operation.

| | | |
|---|---|---|
| **Operating company** | Boise Cascade | |
| **Facility** | Elgin | |
| **SCR** | Company/Consultant Estimates | NPS ARD Estimates |
| Unit | PB #1 & #2 | PB #1 & #2 |
| Total Annual Cost | $ 1,450,706 | $ 844,824 |
| Emissions Reduction (tpy) | 152 | 153 |
| Cost-Effectiveness ($/ton) | $ 9,538 | $ 5,533 |

**Results & Conclusions**
Addition of SCR to Power Boilers #1 & #2 would reduce $NO_X$ emissions by 153 ton/yr and be much less expensive than estimated by All4 and its cost-effectiveness is well below the Oregon threshold.

## Boise Cascade Wood Products, LLC – Medford

**OR DEQ:** In a letter dated January 21, 2021, DEQ notified Boise Cascade Wood Products of its preliminary determination that their Medford facility would likely be required to install SCR on Boilers 1, 2 and 3. Discussions with the facility are ongoing.

**Excerpts from Boise Cascade/All4's June 2020 report, "REGIONAL HAZE RULE FOUR FACTOR ANALYSIS FOR THE BOISE CASCADE WOOD PRODUCTS MEDFORD PLYWOOD MILL"**

***SUMMARY OF RECENT EMISSIONS REDUCTIONS***

Since 2011, the Medford Mill has made improvements to reduce its emissions. The biomass boilers are subject to the provisions of 40 CFR Part 63, Subpart DDDDD, NESHAP for Industrial Commercial, and Institutional Boilers and Process Heaters (NESHAP DDDDD or Boiler MACT). Compliance with these standards required changes to operating practices, including use of clean fuels for startup. Beginning in 2012, combustion efficiency improvements were made on Boilers 2 and 3 so that the Boiler MACT CO limits could be met. These improvements reduced CO emissions but did not increase NOx emissions. Boilers subject to NESHAP DDDDD were required to undergo a one-time energy assessment and are required to conduct tune-ups at a frequency specified by the rule.

**FOUR FACTOR ANALYSIS FOR BOILERS**

The three boilers are biomass hybrid suspension grate units, are controlled by a dry electrostatic precipitator (ESP), and produce 50,000, 70,000, and 100,000 pounds of steam per hour at capacity, respectively. The Medford Mill typically operates two of the boilers at a time.

**Site Specific Factors Limiting Implementation**

Currently known, site-specific factors that would limit the feasibility and increase the cost of installing additional controls include space constraints. Note that a detailed engineering study for each of the controls evaluated in this report would be necessary before any additional controls were determined to be feasible or cost effective.

**Selective Catalytic Reduction (SCR)**

Although SCR was not identified in the RLBC search as a technology typically employed on biomass-fired industrial boilers, it has been applied to coal-fired utility boilers. The presence of alkali metals such as sodium and potassium, which are commonly found in wood, but not fossil fuels, will poison catalysts and the effects are irreversible. Other naturally occurring catalyst poisons found in wood are phosphorous and arsenic. Therefore, it is not feasible to place an SCR upstream of a particulate control device on a biomass boiler.

**$PM_{10}$ Emissions**

Due to the typically lower $PM_{10}$ removal efficiencies than dry ESPs, and the generation of wastewater, this analysis does not consider the use of wet controls for $PM_{10}$ emissions control. Fabric filters are rarely implemented on wood-fired boilers due to risk of fire (any retrofit implementation would require a long stretch of ductwork between the economizer and the control device to reduce the risk of fire). ESPs are almost as efficient as the best fabric filters without the fire risk. ESPs can withstand higher temperatures, have a smaller footprint, use less energy, and have lower maintenance requirements and better separation efficiencies than fabric filters. Therefore, use of a fabric filter for $PM_{10}$ control was not considered feasible and was not evaluated. The Elgin Mill biomass boilers are already very well controlled and are subject to Boiler MACT emission limits and work practices.

The Medford Mill biomass boilers are already very well controlled and are subject to a stringent PM emission limit based on a LAER analysis, as well as Boiler MACT emission limits and work practices. Because the August 20, 2019 EPA Regional Haze Guidance mentions that states can exclude sources that have been through LAER review from further analysis, we have not evaluated further PM10 controls on the biomass boilers.

**$S0_2$ Emissions**

The Medford Mill biomass boiler emits very little $SO_2$ because biomass is an inherently low-sulfur fuel.

**NOx Emissions**

NOx emissions from biomass boilers originate primarily from oxidation of fuel bound nitrogen. The Medford Boilers are in the biomass hybrid suspension grate subcategory under the Boiler MACT rule. Biomass is fed to the boilers via air-swept spouts, begins to combust in suspension, and then completes combustion on a grate. Low-NOx burners and water injection are not applicable to this design. The air system is optimized during required Boiler MACT tune-ups and FGR is not likely to provide a significant reduction in NOx.

Add-on NOx controls such as SNCR and SCR require a specific temperature window to be effective. These controls were developed for and have predominantly been applied to fossil fuel fired boilers. There are challenges associated with applying SNCR to an industrial biomass boiler due to variability in boiler load. Good mixing of the reagent and NOx in the flue gas at the optimum temperature window is the key to achieving a NOx reduction for SCR and SNCR. In biomass boilers, this temperature window is a function of the variations in fuel quality and the load on the boiler. The temperature profile in a wood-fired industrial boiler is not as constant as that of a fossil fuel-fired utility boiler. Biomass boilers at forest products mills are often subject to highly variable swings in steaming rate, fuel flow, fuel mix, and bark moisture, depending on mill steam demand, availability of bark, amount of other fuels fired, and weather conditions.

The feasibility of SCR application to biomass boilers is also uncertain. SCR uses a catalyst to reduce NOx to nitrogen, water, and oxygen. SCR technology employs aqueous or anhydrous ammonia as a reducing agent that is injected into the gas stream near the economizer and upstream of the catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. An ammonium salt intermediate is formed at the catalyst surface and subsequently decomposes to elemental nitrogen and water. This technology has been demonstrated mostly on large coal- and natural gas-fired combustion units in the utility industry.

In practice, SCR systems operate at NOx control efficiencies in the range of 70 to 90% for fossil fuel utility boilers. Optimum temperatures for the SCR process range from 480 to 800°F. Due to catalyst plugging and poisoning problems associated with locating the catalyst prior to the particulate control device, an SCR system would have to be installed after an existing particulate control device, and would likely require installation of a gas-fired flue gas re-heater to achieve the optimum reaction temperature (the flue gas temperature for biomass boilers is typically less than 480°F). This would incur associated fuel costs and pollution increases, running counter to the administration's goal to reduce greenhouse gases, assuming there is adequate space to install the size re-heater needed to raise the temperature of the exhaust gas stream to the optimum temperature of 600 °F. Despite these challenges, for purposes of this analysis, we evaluated cost effectiveness of an SCR achieving 90% control, but we incorporated a retrofit factor of 1.5 to account for the difficulty of applying SCR to a biomass boiler and the likely need to add ductwork and to replace the fan to overcome additional pressure drop through the system.

**Site Specific Factors Limiting Implementation**
Currently known, site-specific factors that would limit the feasibility and increase the cost of installing additional controls include space constraints. Note that a detailed engineering study for each of the controls evaluated in this report would be necessary before any additional controls were determined to be feasible or cost effective.

**NOx Economic Impacts**
This section describes the economic impacts associated with each NOx add-on control option evaluated for the boilers. Note that cost effectiveness was evaluated based on the PSEL, and the cost per ton would be even higher if evaluated based on actual emissions.

**SCR for Boiler $NO_X$ Control**
All4 applied a retrofit factor of 1.5 because the EPA cost equations were developed based on utility boiler applications and to account for space constraints, additional ductwork, the need for stack reheat, and the likelihood of needing a new induced draft fan to account for increased pressure drop.

The All4 cost analysis is based on the boilers' capacity and their NOx PSEL of 210 tpy, although actual emissions in 2017 were only 105 tpy. Installing an SCR is not considered cost effective because the capital cost is estimated at more than $27 million and the cost effectiveness values are well in excess of $3,400/ton of pollutant removed, the cost effectiveness threshold for non-EGUs used by EPA for similar studies.

*REMAINING USEFUL LIFE OF EXISTING AFFECTED SOURCES*
All4 assumed that the emissions units and controls included in this analysis have a remaining useful life of twenty years or more.

*CONCLUSION*
Based on the Four Factor analysis presented above, All4 concluded that no additional controls were determined to be cost effective for the biomass boilers at the Medford Mill.

**NPS Air Resources Division (ARD) Analysis**

**Technical Feasibility of SCR on Wood-fired Boilers**
The excerpt below if from the New Hampshire draft Regional Haze SIP:
**Burgess BioPower**: The biomass unit at this facility was subject to NNSR for NOx at the time of their initial permitting; hence, the NOx limit was established as the LAER[7] based limit. The NOx limit currently contained in the PSD/NNSR Permit TP-0054 is 0.060 lbs NOx/MMBtu on a 30-day rolling average, based on the use of SCR technology. Burgess BioPower uses clean wood as their fuel during normal operations and ULSD during plant startups. Both fuels are inherently very low in sulfur. The Burgess BioPower facility was also subject to PSD review for $SO_2$ at the time of its initial permitting in 2010; hence, the $SO_2$ limit in their current PSD/NNSR Permit TP-0052 of 0.012 lbs. $SO_2$/MMBtu was established as a BACT based limit. A June 2018 review of the USEPA RBLC for biomass fired EGUs greater than or equal to 25 MW indicates that low sulfur fuels remains the $SO_2$ BACT. Sorbent injection was installed for acid gas control but is not used to control $SO_2$ emissions because the emissions from burning wood are inherently very low (typically around 0.001 lbs $SO_2$/MMBtu). Monitoring data at the facility has shown that operation of the sorbent injection is not necessary to comply with the emission limit for $SO_2$. For this reason, NHDES has determined that the current limits for the above facilities represent the “most effective use of control technologies” for NOx and $SO_2$. Low-sulfur fuels and SCR are required by TP-0054 during year-round operations.

We have several concerns with the Boise Cascade analyses conducted by All4.

**Retrofit Factor**
All4 assumed a retrofit factor of 1.5 for every woodwaste boiler it evaluated in Oregon. The EPA Control Cost Manual (CCM) recommends that site-specific retrofit factors (greater than the 1.0 default value) should be based upon a thorough and well-documented analysis of the individual factors involved in a project. For example, the methods outlined by William Vatavuk on pages 59-62 in his book Estimating Costs of Air Pollution Control be followed. That process involves estimating and assigning a retrofit factor to each major element of a project and from that deriving an overall retrofit factor. The CCM also addresses “Retrofit Cost Considerations” in section 2.6.4.2. In the absence of such a proper analysis, assume a retrofit factor = 1.0, which represents a 30% increase above costs for a “greenfield” project. The All4 blanket application of the maximum retrofit factor falls short of the justification and documentation required by the CCM and EPA policy.

**SCR Equipment Life**
All4 assumed a 20-year life for these boilers; for all other woodwaste-fired boilers All4 evaluated in Oregon and Washington, All4 assumed 25-year life. We used the CCM default = 25 years.

[7] A June 2018 review of the USEPA RBLC for biomass fired boilers greater than or equal to 250 MMBtu/hr indicates that 0.060 lb/MMBtu remains as LAER for NOx. While two recent determinations for similar facilities in Vermont established emission rates as low as 0.030 lb/MMBtu on a 12-month rolling period, NHDES understands that these rates have yet to be confirmed. The associated short term limits for these two facilities are 0.060 lb/MMBtu.

**Chemical Engineering Plant Cost Index (CEPCI)**
All4 used a 2019 CEPCI = 603.1; the correct CEPCI = 607.5.

**Interest Rate**
All4 used a 4.75% interest rate instead of the current bank prime rate = 3.25% as recommended by the CCM.

**Operating Costs**
All4 overestimated the operating costs of SCR (and SNCR) when it substituted values for "Total operating time for the SCR ($t_{op}$)" and "Total NOx removed per year" for the values calculated by the CCM "Design Parameters" spreadsheets. We participated in the EPA work group that developed the CCM workbooks for $NO_X$ (and $SO_2$) controls and can advise that it is not appropriate to alter values in the "Design Parameters" spreadsheet because these values should, instead, be generated from the "Data Inputs" spreadsheet and the algorithms that operate on them according to the methods and equations described in the CCM.

The "Total operating time for the SCR ($t_{op}$)" parameter is not meant to be the actual operating time for the control device, which All4 entered directly into the "Design Parameters" spreadsheet. Instead, it represents a method to adjust capacity utilization to actual (or permitted) utilization based upon a fraction (Total System Capacity Factor ($CF_{total}$)) applied to the maximum capacity. All4 compounded its error by also over-riding the calculation of Total NOx removed per year to reflect percent removed from the PSEL or actual conditions instead of percent removed from the emissions that would have resulted from All4's hours of operation.

The basic parameters (on the "Data Inputs" spreadsheet) that define emissions and control costs are:

- maximum heat input rate (QB)
- higher heating value (HHV) of the fuel
- estimated actual annual fuel consumption
- net plant heat input rate (NPHR)
- Number of days the SCR (or SNCR) operates ($t_{SCR}$ or $t_{SNCR}$)
- Number of days the boiler operates ($t_{plant}$)
- Inlet NOx Emissions ($NO_{Xin}$) to SCR (or SNCR)
- Outlet NOx Emissions ($NO_{Xout}$) from SCR (or SNCR)

All but "estimated actual annual fuel consumption" are essentially fixed by the boiler, fuel, and control device characteristics. The "Number of days the SCR operates (tSCR)" typically equals "Number of days the boiler operates (tplant)."[8] We adjusted "estimated actual annual fuel consumption" to yield the uncontrolled emissions specified by All4.

For example, the "Total operating time for the SCR ($t_{op}$)" parameter is not meant to be the actual operating time for the control device. Instead, it represents a method to adjust capacity utilization to actual utilization based upon a fraction (Total System Capacity Factor ($CF_{total}$) applied to the maximum capacity. For the Power Boiler (PSEL), All4's workbook overrode the calculated the

[8] In March 2021, EPA revised the SNCR workbook to include an entry for the "Number of days the boiler operates (tplant)." Until that revision, the SNCR workbook assumed 365 days of plant operation.

Total System Capacity Factor = 0.49 and instead entered 0.97. All4 also overrode that result by entering 8760 hours for Total operating time for the SCR instead of the value of 4311 hours that would have been calculated by the spreadsheet. All4 then allowed the workbook to calculate annual operating costs as if the SCR were operating at maximum capacity 8760 hours instead of 4311 hours. All4 compounded its error by also overriding the calculation of Total NOx removed per year.

All4 included property taxes in several analyses. It is our understanding that Oregon allows exemptions from property taxes for air pollution control equipment.

We applied the CCM workbook and adjusted the "estimated actual annual fuel consumption" to yield the uncontrolled emissions (210 ton/yr) specified by All4. Our results are shown below.

| **SCR** | **Company/Consultant Estimates** | **NPS ARD Estimates** |
|---|---|---|
| Unit | PB #1 & #2 & #3 | PB #1 & #2 & #3 |
| Emissions Reduction (tpy) | 189 | 190 |
| Total Annual Cost | $ 2,527,428 | $ 1,269,194 |
| Cost-Effectiveness ($/ton) | $ 13,373 | $ 6,679 |

**Results & Conclusions**
Addition of SCR to Power Boilers #1, & #3 #2 would reduce $NO_X$ emissions by 189 ton/yr and be much less expensive that estimated by All4 and its cost-effectiveness is well below the Oregon threshold.

**Cascade Pacific Pulp**
**Halsey Pulp Mill**
**July 1, 2021**

**Excerpts from the company submittal dated June 2020**

**Power Boilers #1 & #2**

**Power Boiler $PM_{10}$ Emissions**
The Nos. 1 and 2 Power Boilers at the Cascade Pacific Pulp (CPP) Halsey Mill fire natural gas and have minimal $PM_{10}$ emissions. The No. 1 Power Boiler is permitted to burn No. 6 fuel oil, but this fuel is only burned during periods of gas curtailment.

**Power Boiler $NO_X$ Emissions**
The design of the CPP Halsey No. 2 Power Boiler is such that a simple burner replacement may not be feasible. The boiler's cyclopack burner is integrated into the side wall of the boiler and to change the burner, tubing and refractory would have to be reconfigured. Therefore, the cost of LNB/FGR on this boiler would likely be higher than estimated.

**Power Boiler $SO_2$ Emissions**
Fuel oil is fired in the No. 1 Power Boiler only when natural gas is curtailed, resulting in lower $SO_2$ emissions.

**Recovery Furnace**
The CPP Halsey Mill installed a new air system on their recovery furnace in 2010 and rebuilt the ESP in order to reduce emissions.

**Lime Kiln**

**Lime Kiln $SO_2$ Emissions**
The Mill also no longer fires petroleum (pet) coke in the lime kiln, resulting in lower $SO_2$ emissions. The CPP Halsey lime kiln's portion of the $SO_2$ PSEL is 68.4 tpy, but 65.7 tpy of the PSEL is from combustion of pulp mill NCG that contain sulfur compounds. The kiln's venturi scrubber is designed for PM control and has a very short residence time. No caustic is added to this scrubber and the short residence time would preclude achieving significant additional $SO_2$ control if a caustic solution were used. Although the kiln is the backup control device for NCG combustion, addition of a packed bed scrubber to further reduce $SO_2$ emissions from this kiln was evaluated (rather than replacing the venturi scrubber with a caustic wet scrubber and potentially decreasing the $PM_{10}$ control efficiency).

**$SO_2$ Economic Impacts**
The U.S. EPA's fact sheet on packed bed scrubbers[19] was used to develop a rough estimate of capital and annual costs for a packed bed scrubber on the CPP Halsey lime kiln. The fact sheet indicates that capital cost ranges from $11 to $55 per scfm and annual cost ranges from $17 to $78 per scfm. The flow rate from the CPP Halsey lime kiln is approximately 25,000 scfm. Using the low end of the cost ranges in the fact sheet results in a capital cost estimate of $275,000 and an

annual cost estimate of $425,000 per year. Assuming the packed bed scrubber would achieve 98 percent control of the lime kiln's portion of the $SO_2$ PSEL of 68.4 tpy, the cost effectiveness is at least $6,340. Installing a packed bed scrubber after the venturi scrubber to achieve additional $SO_2$ control from periodic NCG combustion in the CPP Halsey lime kiln is not cost effective.

**Lime Kiln $PM_{10}$ Emissions**

CPP Halsey utilizes a wet scrubber for PM control on its lime kiln. An ESP prior to the wet scrubber would provide additional $PM_{10}$ control and is considered technically feasible.

**PAPER MACHINES AND PULP DRYERS**

Paper machines and pulp dryers consist of the wet end and the dry end and the combined equipment can be the length of a football field and have many different exhaust points through roof vents or building exhausts. On the wet end, pulp is combined with additives and diluted with water at the head box, applied to the former or wire, where it forms a sheet as the water drains, and then travels to the press and dryer sections (dry end) to remove the remaining water. The paper machines at GP Toledo and IP Springfield and the pulp dryer at CPP Halsey are steam heated and do not have emissions of $NO_X$ or $SO_2$.

**OR DEQ**

In a letter dated January 21, 2021, OR DEQ notified CPP of its preliminary determination that their Halsey facility would likely be required to install LNB/Flue Gas Recirculation on their Power boiler #1, and also switch to Ultra Low Sulfur Diesel instead of #6 fuel oil as an emergency backup fuel on site.

**ARD Comments**

CPP and its consultant (All4) have overestimated capital and operating costs of applying SCR to the power boilers (PB#1 & #2). The All4 application of the maximum retrofit factor falls short of the justification and documentation required by the CCM and EPA policy.

All4 also overestimated the operating costs of SCR when it substituted values for "Total operating time for the SCR ($t_{op}$)" and "Total NOx removed per year" for the values calculated by the CCM "Design Parameters" spreadsheets. For example, for the PB#1 (PSEL), All4's workbook correctly calculated the Total System Capacity Factor = 0.422 but over-rode that result by entering 8760 hours for Total operating time for the SCR instead of the value of 3697 hours that would have been calculated by the spreadsheet. All4 then allowed the workbook to calculate annual operating costs as if the SCR were operating 8760 hours instead of 3697 hours. All4 compounded its error by also over-riding the calculation of Total NOx removed per year to reflect 90% removed from the PSEL (90% * 132.5 tpy) instead of 90% removed from the emissions (286 tpy) that would have resulted from All4's 8760 hours of operation (90% * 286 tpy). Instead, we adjusted "estimated actual annual fuel consumption" to yield the uncontrolled emissions specified by All4.

All4's resulting Total Annual Cost of $1.9 million for PB#1 contains several overestimated cost components. The capital cost was escalated by 50% due to the application of an unjustified retrofit factor. (All4 also used a 4.75% interest rate instead of the current bank prime rate =

3.25% as recommended by the CCM.) Operating costs were overestimated by more than a factor of two due to over-riding of the "Total operating time" parameter. All4 also overestimated reagent costs by more than an order of magnitude with no justification, and included costs for reheating the SCR inlet gas stream with no explanation of how this cost was derived. (All4's fuel cost of $5.00/mmBtu exceeds the approximately $4.00/mmBtu Oregon industrial price for natural gas according to the EIA. [9]) Instead of All4's estimated cost-effectiveness = $16,029/ton; we estimate a Total Annual Cost of $0.75 million = $6253/ton for addition of SCR to remove 121 ton/yr of $NO_X$. (Even though there was no justification provided for the reheat fuel use rate, we accepted All4's estimate to estimate reheat cost—please see the attached workbooks.)

The same issues apply to PB#1 at actual conditions as well as PB#2. We applied the SCR CCM workbook to PB#1 & #2 for both the PSEL and actual conditions and the cost-effectiveness of adding SCR fall below the OR DEQ threshold of $10,000/ton for the PSEL cases for both boilers. The cost effectiveness of adding SCR for PB#2 clearly exceeds the OR DEQ threshold under actual conditions. Addition of SCR to PB#1 under actual conditions is slightly above the OR DEQ threshold and the costs of reheating the SCR inlet gas stream should be further investigated.

| **SCR** | **Company/Consultant Analysis** | | **NPS ARD Analysis** | |
|---|---|---|---|---|
| Unit | #1 PB (PSEL) | #1 PB (actual) | #1 PB (PSEL) | #1 PB (actual) |
| Emissions Reduction (tpy) | 119 | 48 | 121 | 48 |
| Total Annual Cost | $ 1,911,460 | $ 1,826,543 | $ 754,862 | $ 565,360 |
| Cost-Effectiveness ($/ton) | $ 16,029 | $ 38,292 | $ 6,253 | $ 11,684 |

| **SCR** | Company/Consultant Analysis | | NPS ARD Analysis | |
|---|---|---|---|---|
| Unit | #2 PB (PSEL) | #2 PB (actual) | #2 PB (PSEL) | #2 PB (actual) |
| Emissions Reduction (tpy) | 68 | 5 | 68 | 5 |
| Total Annual Cost | $1,916,103 | $ 1,028,580 | $ 588,791 | $ 386,630 |
| Cost-Effectiveness ($/ton) | $ 28,349 | $ 204,083 | $ 8,617 | $ 70,695 |

**Results & Conclusions**

- The cost-effectiveness of adding SCR fall below the OR DEQ threshold of $10,000/ton for the PSEL cases for both boilers.
- Addition of SCR to PB#1 under actual conditions is slightly above the OR DEQ threshold and the costs of reheating the SCR inlet gas stream should be further investigated.
- The cost effectiveness of adding SCR for PB#2 clearly exceeds the OR DEQ threshold under actual conditions.
- Addition of SCR to these two boilers could reduce $NO_X$ emissions by 189 tons/yr under PSEL conditions or 53 tons/yr under actual conditions.

[9] Oregon Natural Gas Industrial Price (Dollars per Thousand Cubic Feet) (eia.gov)

**International Paper**
**Springfield Mill**
**July 1, 2021**

**Excerpts from the company submittal dated June 2020**
The International Paper (IP) Springfield Mill is permitted to fire fuel oil in its lime kiln, boilers, and recovery furnace, but burns natural gas instead, resulting in lower $PM_{10}$ and $SO_2$ emissions. The Mill no longer fires pet coke in the lime kiln, resulting in lower $SO_2$ emissions. The Mill is already subject to a Federally enforceable permit limit on $SO_2$ and $NO_X$ emissions that was implemented in the 2008 Oregon Regional Haze Plan to reduce the visibility impact of the BART-eligible units (including the Power Boiler).

**Power Boilers**
**$NO_X$ Emissions**
<u>LNB and FGR for Boiler $NO_X$ Control</u>
Installing LNB/FGR is not considered cost-effective for the IP Springfield Power Boiler. Although the estimated cost per ton is lower than the other boilers when based on its assigned portion of the PSEL, when actual emissions are evaluated, the estimated cost is much higher and above any reasonable cost effectiveness threshold. The IP Springfield Package Boiler already uses LNB and FGR to reduce $NO_X$ emissions.

**$PM_{10}$ Emissions**
The Package Boiler and the Power Boiler at the IP Springfield Mill burn natural gas, with No. 2 fuel oil as backup fuels for periods of natural gas supply interruption or natural gas curtailment. No $PM_{10}$ controls beyond burning natural gas as the primary fuel and limiting oil firing to periods of curtailment are feasible for these boilers.

**Lime Kiln**
**PM10 Emissions**
The IP Springfield Mill uses a dry ESP for control of PM emissions from their lime kiln. An ESP upgrade for additional PM10 control is considered technically feasible.

**$SO_2$ Emissions**
The lime kilns provide inherent control of $SO_2$ through absorption of sulfur by the calcium in the kiln. All the mills fire natural gas as the primary fuel in their lime kilns, which minimizes SO2 emissions, particularly during startup and shutdown. Addition of a wet scrubber with caustic addition (following the ESP) for additional SO2 control was evaluated for the IP Springfield lime kilns (which also burn pulp mill NCG).

**$SO_2$ Economic Impacts**
The wet scrubber capital cost for the IP Springfield lime kilns was estimated by scaling the recovery furnace wet scrubber cost in the BE&K report using an engineering cost scaling factor of 0.6 and the ratio of the estimated kiln exhaust flow rate to the estimated exhaust flow rate of

the furnace evaluated in the BE&K report. Operating costs were estimated using the factors in the OAQPS Cost Manual, Section 5, Chapter 1.

***PAPER MACHINES AND PULP DRYERS***

Paper machines and pulp dryers consist of the wet end and the dry end and the combined equipment can be the length of a football field and have many different exhaust points through roof vents or building exhausts. On the wet end, pulp is combined with additives and diluted with water at the head box, applied to the former or wire, where it forms a sheet as the water drains, and then travels to the press and dryer sections (dry end) to remove the remaining water. The paper machines at IP Springfield are steam heated and do not have emissions of $NO_X$ or $SO_2$.

Concentrations of PM are very low in each paper machine vent, as discussed in NCASI Technical Bulletin No. 942, "Measurement of PM, $PM_{10}$, $PM_{2.5}$ and CPM Emissions from Paper Machine Sources," November 2007 (updated February 2017). PM emissions include both filterable (FPM) and CPM, with the FPM coming primarily from the pulp fibers and the CPM resulting from organics. Limited NCASI test data indicate that the FPM concentrations for paper machine vents average less than 0.0004 gr/dscf at each vent (not including tissue machine vents). There are no known control technologies that would remove particulate matter at such a low concentration. It is expected that pulp dryer vent concentrations would be similarly low or lower because the sheet of pulp is thicker and typically has a higher moisture content than paper. BACT analyses for paper machines and pulp dryers routinely indicate that add-on controls are not feasible. Note that IP Springfield has eliminated the New Fiber Line emission unit (EU-402), which had a $PM_{10}$ PSEL of 427 tpy, so this unit is not evaluated here.

**OR DEQ**

In a letter dated January 21, 2021, DEQ notified International Paper of its preliminary determination that their Springfield facility would likely be required to install SCR on the Power Boiler (EU-150A) and also take several actions related to restricting alternative or emergency fuels.

**ARD Comments**

IP and its consultant (All4) have overestimated capital and operating costs of applying SCR to the Power Boiler and the Package Boiler. All4 overestimated capital costs when it assumed a retrofit factor of 1.5 without the justification and documentation required by the CCM and EPA policy.

All4 also overestimated the operating costs of SCR when it substituted values for "Total operating time for the SCR ($t_{op}$)" and "Total NOx removed per year" for the values calculated by the CCM "Design Parameters" spreadsheets. For example, for the Power Boiler (PSEL), All4's workbook correctly calculated the Total System Capacity Factor = 0.797 but over-rode that result by entering 8760 hours for Total operating time for the SCR instead of the value of 6982 hours that would have been calculated by the spreadsheet. All4 then allowed the workbook to calculate annual operating costs as if the SCR were operating at maximum capacity 8760 hours instead of 6982 hours. All4 compounded its error by also over-riding the calculation of Total NOx removed per year to reflect 90% removed from the PSEL (90% * 873.74 tpy) instead of 90% removed from the emissions (986 tpy) that would have resulted from All4's 8760 hours of operation (90%

* 986 tpy). Instead, we adjusted “estimated actual annual fuel consumption” to yield the uncontrolled emissions specified by All4.

All4’s resulting Total Annual Cost of $3.6 million for the Power Boiler contains several overestimated cost components. The capital cost was escalated by 50% due to the application of an unjustified retrofit factor. (All4 also used a 4.75% interest rate instead of the current bank prime rate = 3.25% as recommended by the CCM.) Operating costs were overestimated due to over-riding of the “Total operating time” parameter. All4 also overestimated reagent costs by more than an order of magnitude with no justification, and included costs for reheating the SCR inlet gas stream with no explanation of how this cost was derived. (All4’s fuel cost is 25% higher than the current Oregon industrial natural gas price.[10]) Instead of All4’s estimated cost-effectiveness = $4606/ton; we estimate a Total Annual Cost of $1.6 million = $2010/ton for addition of SCR to remove 786 ton/yr of $NO_X$. (Even though there was no justification provided for the reheat fuel use rate, we accepted All4’s estimate to estimate reheat cost—please see the attached workbooks.)

The same issues apply to the Power Boiler at actual conditions as well as the Package Boiler. We applied the SCR CCM workbook to these boilers for both the PSEL and actual conditions and the cost-effectiveness of adding SCR fall below the OR DEQ threshold of $10,000/ton for the PSEL cases for both boilers, and for the Power Boiler under actual conditions. The cost effectiveness of adding SCR for the Package Boiler clearly exceeds the OR DEQ threshold under actual conditions.

| **SCR** | Company/Consultant Estimates | | NPS/ARD Estimates | |
|---|---|---|---|---|
| Unit | IP Springfield PB (PSEL) | IP Springfield PB (actuals) | IP Springfield PB (PSEL) | IP Springfield PB (actuals) |
| Emissions Reduction (tpy) | 786 | 126 | 786 | 127 |
| Total Annual Cost | $ 3,621,820 | $ 2,895,491 | $ 1,580,780 | $ 1,117,502 |
| Cost-Effectiveness ($/ton) | $ 4,606 | $ 22,924 | $ 2,010 | $ 8,828 |

| **SCR** | Company/Consultant Estimates | | NPS/ARD Estimates | |
|---|---|---|---|---|
| Unit | IP Springfield PkgBlr (PSEL) | IP Springfield PkgBlr (actuals) | IP Springfield PkgBlr (PSEL) | IP Springfield PkgBlr (actuals) |
| Emissions Reduction (tpy) | 268 | 1 | 268 | 1 |
| Total Annual Cost | $ 2,130,423 | $ 825,603 | $ 1,583,260 | $ 891,894 |
| Cost-Effectiveness ($/ton) | $ 7,948 | $ 655,241 | $ 5,906 | $ 706,194 |

**Results & Conclusions**

- Addition of SCR to the Power Boiler and Package Boiler is much less expensive than estimated by IP and its cost-effectiveness would not exceed the OR DEQ threshold under PSEL operating conditions.

[10] Oregon Natural Gas Industrial Price (Dollars per Thousand Cubic Feet) (eia.gov)

- Addition of SCR to the Power Boiler is much less expensive than estimated by IP and its cost-effectiveness would not exceed the OR DEQ threshold under actual operating conditions.
- Addition of SCR to the Package Boiler would exceed the OR DEQ threshold under actual operating conditions.
- Addition of SCR to the Power Boiler could reduce $NO_X$ emissions by 786 tons/yr under PSEL conditions or 127 tons/yr under actual conditions.

**(From Andrea Stacey)**

***NPS Air Resources Division Review of Gas Transmission NW Compressor Stations 12 & 13***

***07/07/2021***

**Gas Transmission Northwest Compressor Station No. 12**:

- The company did not use the most recent 7th edition CCM. Why wasn't the most recent version of the CCM SCR chapter used?

- The company assumed a 75% control efficiency. This seems low for SCR. What is the basis for this assumption? As described below, our analysis assumed 90% control. This is equivalent to a controlled NOx limit of 0.037 lb/MMBtu for unit 12-A and 0.017 lb/MMBtu for unit 12-B. The CCM states: "In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent."

  We reviewed the most recent (2020) CAMD information to verify whether the NPS assumed emission rate at 90% control was reasonable (i.e., achieved in practice) for natural gas-fired combustion turbines—we did not include combined cycle units in this review. There are over 100 combustion turbines in the CAM database with emission rates at or below the 0.017 lb/MMBtu limit assumed in our review. Based on this, we concluded that 90% NOx control by SCR is achievable in practice and reasonable to assume in the cost analysis.[11]

- The company assumed 3% sales tax. Does Oregon charge sales tax for pollution control projects? Please note, the revised 7th edition of the CCM does not include sales tax in the cost analysis.

- The company assumed property taxes for the PCE on each CT. Does Oregon charge property taxes on this equipment? Please note, the revised 7th edition of the CCM does not include property tax in the cost analysis.

- The company assumed a cost of $2,765,000 to $3,712,500 for combustion controls in addition to SCR on the CTs—is it assumed the applicant would need both controls to achieve 75% NOx reductions? What is the basis for this?

- The company assumed $105,326 to $143,628 in administrative charges for each CT. This seems high. (Note when using the revised 7th Edition CCM, the estimated administrative charges are roughly $3000/year in 2019$.) What is the basis for these annual costs?

- The company used a 5% interest rate and a 20-year equipment life. We agree with DEQ that unless additional source-specific documentation can be provided, the current bank prime rate (3.25%) should be assumed. In addition, we used the 30-year equipment life assumption recommended by Oregon DEQ.

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[11] When restricting the dataset to small combustion turbines (< 250 MMBtu/hr heat input) we found six examples of natural gas-fired emission units with SCR achieving lower NOx emission rates than what was assumed in our analysis.

- **NPS Revised Analysis for Station 12:** The NPS re-evaluated the costs of controls for the three turbines at compressor station No. 12 using the more recent 7th edition CCM & fixed the issues noted above. We found the following:

  - Using PSEL assumptions, the costs to add SCR to turbines 12-A and 12-B are significantly lower than DEQ's $10,000/ton threshold at $1,833/ton of NOx removed for unit 12-A and $3,801/ton of NOx removed for unit 12-B. (See attached spreadsheets.) The costs to install SCR on unit 12-C, which is newer than the other two turbines and consequently has far lower NOx emissions, exceeds DEQ's cost threshold when using PSEL assumptions.

  - When using reduced operating scenarios (based on reduced fuel use assumptions), the cost of installing SCR is still below DEQ's cost threshold down to ***16% of full capacity for unit 12-A and 34% of full capacity for unit 12-B***, suggesting that SCR is likely still cost effective under reduced operating scenarios.

  - Therefore, we concur with DEQ's determination documented in a January 21, 2021 letter to the company, that SCR is likely cost effective at units 12-A and 12-B. However, we recommend that DEQ correct some of the additional errors identified in the cost analysis (other than interest rate and equipment life), as this results in SCR being a much more cost effective option than estimated by DEQ or the company. Spreadsheets documenting our revised analyses are attached.

**Gas Transmission Northwest Compressor Station No. 13**:

- The company did not use the most recent 7th edition CCM. Why wasn't the most recent version of the CCM SCR chapter used?

- The company assumed a 75% control efficiency. This seems low for SCR. What is the basis for this assumption? As described below, our analysis assumed 90% control. This is equivalent to a controlled NOx limit of 0.017 lb/MMBtu for unit 13-D and 0.016 lb/MMBtu for unit 13-C. The CCM states: "In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent."

  We reviewed the most recent (2020) CAMD information to verify whether the NPS assumed emission rate at 90% control was reasonable (i.e., achieved in practice) for natural gas-fired combustion turbines—we did not include combined cycle units in this review. There are over 100 combustion turbines in the CAM database with emission rates at or below the 0.016 lb/MMBtu limit assumed in our review. Based on this, we concluded that 90% NOx control by SCR is achievable in practice and reasonable to assume in the cost analysis.[12]

- The company assumed 3% sales tax. Does Oregon charge sales tax for pollution control projects? Please note, the revised 7th edition of the CCM does not include sales tax in the cost analysis.

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[12] When restricting the dataset to small combustion turbines (< 250 MMBtu/hr heat input) we found six examples of natural gas-fired emission units with SCR achieving lower NOx emission rates than what was assumed in our analysis.

  - The company assumed property taxes for the PCE on each CT. Does Oregon charge property taxes on this equipment? Please note, the revised 7th edition of the CCM does not include property tax in the cost analysis

  - The company assumed a cost of $2,765,000 for combustion controls in addition to SCR on the CTs—is it assumed the applicant would need both controls to achieve 75% NOx reductions? What is the basis for this?

  - The company assumed $105,326 in administrative charges for each CT (13C and 13D). This seems high. (Note when using the revised 7th Edition CCM, the estimated administrative charges are roughly $3000/year in 2019$.) What is the basis for these annual costs?

  - The company used a 5% interest rate and a 20-year equipment life. We agree with DEQ that unless additional source-specific documentation can be provided, the current bank prime rate (3.25%) should be assumed. In addition, we used the 30-year equipment life assumption recommended by Oregon DEQ.

- **<u>NPS Revised Analysis for Station 13</u>**: The NPS re-evaluated the costs of controls for the three turbines at compressor station No. 13 using the more recent 7th edition CCM & fixed the issues noted above. We found the following:

  - Using PSEL assumptions, the costs to add SCR to turbines 13-C and 13-D are significantly lower than DEQ's $10,000/ton threshold at $4,074/ton of NOx removed for unit 13-C and $3,887/ton of NOx removed for unit 13-D. (See attached spreadsheets.)

  - When using reduced operating scenarios (based on reduced fuel use assumptions), the cost of installing SCR is still below DEQ's cost threshold down to ***37% of full capacity for unit 13-C and 35% of full capacity for unit 13-D***, suggesting that SCR is likely still cost effective under reduced operating scenarios.

  - Therefore, we concur with DEQ's determination, documented in a January 21, 2021 letter to the company, that SCR is likely cost effective for units 13-C and 13-D. However, we recommend that DEQ correct some of the additional errors identified in the cost analysis (other than interest rate and equipment life), as this results in SCR being a much more cost effective option than estimated by DEQ or the company. Spreadsheets documenting our revised analyses are attached.

**(From Debra Miller)**
**April 2, 2021**

Thanks for sharing the four factor analyses with us. I have reviewed the analysis for the Roseburg FP Dillard facility and the Biomass One facility and have some initial feedback.

The costs for SNCR at the Roseburg FP Dillard facility appear to be reasonable as presented in the four factor analysis, but it looks like an interest rate of 4.75% was used, rather than the current bank prime rate of 3.25% as recommended by the control cost manual. In addition, it looks like the analysis relied upon an old reference to calculate capital costs (*USEPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-031) for selective non-catalytic reduction (SNCR),* issued July 15, 2003.) For most other calculations the consultant appears to have used equations from the EPA control cost manual from 2017 so it is unclear why a different method was chosen for the capital costs. The capital costs should be estimated using the methods from the control cost manual. There is also an EPA worksheet available to estimate SNCR costs that employs the guidance in the EPA manual.

The Dillard analysis dismisses the use of SCR for NOx emissions reduction as technically infeasible because of the potential for wood combustion byproducts to foul or plug the catalyst. However, there are other facilities powered by wood combustion that have successfully employed tail-end SCR. One is the Bridgewater electrical generating facility in Bridgewater, New Hampshire, which uses a 250 mmbtu/hr wood-fired boiler. An additional New Hampshire facility, Burgess BioPower, uses SCR for NOx control and has a limit of 0.06 lb NOx/MMbtu. Tail-end SCR is technically feasible for the Dillard facility and should be evaluated to determine if it is cost effective. I ran cost estimates using the EPA recommended worksheet for the three boilers and it appears the cost for SCR may be reasonable (see attached example). It wasn't completely clear to me from the four factor analysis how much natural gas vs. wood is combusted, but the SNCR analysis appeared to use the heating value of wood so I assumed that it is the primary fuel.

I reviewed the BiomassOne analysis as well. There were two cost estimates provided for SCR—one in the four factor analysis and a separate, more recent response based upon a vendor estimate from Halgo Power. Looking at the more recent estimate, BiomassOne used an interest rate of 4.75% instead of the current prime rate of 3.25% and assumed a 20-year lifetime rather than 30 years as recommended in the EPA control cost manual. The analysis indicated that Halgo's recommendation was a 20-year useful life but I didn't see that in the attached estimate. Using the company's calculation methods with an interest rate of 3.25% and useful life of 30 years brings the cost per ton to about $7,000.

**(From Debra Miller)**
**June 3, 2021**

I looked at your initial determination in the SIP for the Roseburg Forest Products—Dillard facility. I sent some feedback on their four factor analysis earlier, which I attached below. I see that the SIP says that SNCR would be cost effective on all three boilers, and I agree. I was curious whether tail-end SCR was ever evaluated. As I mentioned earlier, there are some other biomass boilers using tail-end SCR. I ran some estimates for both SNCR and SCR using the EPA costing worksheets, and the results suggest that SCR may be even more cost effective than SNCR given the greater NOx reduction ($2,800-$3,500 per ton). I have attached some cost estimates for comparison.

The SIP also indicates that SCR is cost effective for the two boilers at BioMass One, and I agree with that as well. I used EPA's most recent cost estimation worksheet (7th edition of the Control Cost manual) rather than the company's methods. I attached examples for the South Boiler using the PSEL as well as actual emissions. The results suggest that SCR is more cost effective than indicated by the company's analysis ($5,000 to $6,900 per ton).