From: Kuskie, Melissa (MPCA)
To: Addonizio, Craig (COMM); Aditya Jayam Prabhakar; Alexis Williams; Ali Nouri; Amy Fredregill; Andy Kellen; Anna Sommer; Annie Levenson-Falk; B. Cook; Ben Gerber; Beth Soholt; Bill Droessler; Bill Hamlin; Boise Jones; Brad Crabtree; air@lldrm.org; Brian Rounds; Brickwedde, Peter (COMM); Cain, Alexis; Cecilia Martinez; Charlie Lippert; Ciborowski, Peter (MPCA); Claire Moeller; Courtney Harris; Craig Diekvoss; Dower, Tom; Drew Moratzka; Eddie.Terrill@deq.ok.gov; Edward Garvey; Elizabeth Wefel; Ellen Anderson; Eric Jensen; Fenske, MaryJean (MPCA); Franz Litz; G Sopkin; Gonzalez, Janet (PUC); Grant, Bill (COMM); Groebner, Alison (COMM); Haar, Burl (PUC); Henderson, Anna (MPCA); Heydinger, Beverly (PUC); Hogan, Tom (MDH); Holmes, Karron (MPCA); Izzo, Katie (MPCA); J. Drake Hamilton; Jack Ihle; Jackie Blair; Jackson, Anne M (MPCA); James Alders; Jerome Malmquist; Joe Hoch; John Knapp; Joseph K. Sullivan; Josh Smith; joywiecks@fdlrez.com; K Blake; Karen Monahan; Katherine Blauvelt; James.kelly@state.mn.us; Kevin Johnson; Kevin Reuther; Kohlasch, Frank (MPCA); Kovacevic, Azra (MPCA); Kristin Henry; Kurdila, Julianne; Kuskie, Melissa (MPCA); Lahd, Holly (COMM); Lange, Nancy (PUC); Larry Johnson; Leigh Currie; Lipschultz, Dan (PUC); M Larson; Margaret Hodnick; Mark Mitchell; Mark Strohfus; Mark Thoma; Mary Jo Roth; Megan Ceronsky; Michael Binnion; Michele Pluta; Michelle Rosier; Mike Bull; Mike Cashin; Mike Myser; Mrg Simon; Murphy, Caitlin (Franken); Neuschler, Catherine (MPCA); Nicholas Bianco; Nick Martin; O'Connell, Kate (COMM); Pam Kiely; Peirce, Susan (COMM); Priti Patel; Rick Rosvold; Robert Jagusch; Ruzycki, Zac (COMM); Sarah Johnson Phillips; Sarah Lynch; Seuffert, Will (MPCA); Shalina Gupta; Shaw, Christopher (COMM); Sierks, Bill (MPCA); sdavis@ccap.org; Stalpes, Sean (PUC); Stan Ellison; Steve Jackson; Steven Frenkel; Thor Underdahl; Thornton, J. David (MPCA); Tim VanSumeren; Tony Kwilas
Sent: 12/1/2014 3:55:55 PM
Subject: Minnesota's Clean Power Plan Comments - Docket ID No. EPA-HQ-OAR-2013-0602
Attachments: Final_Minnesota_Clean Power Plan comments.pdf; removed.txt

Attached are comments on EPA's proposed Clean Power Plan, signed jointly by the commissioners of the Minnesota Department of Commerce and Pollution Control Agency. Comments have been submitted electronically to EPA's docket.

Thanks,
Melissa

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December 1, 2014

Ms. Gina McCarthy, Administrator
U.S. Environmental Protection Agency
William Jefferson Clinton Building
1200 Pennsylvania Avenue, N. W.
Mail Code: 1101A
Washington, D.C. 20460

RE: Docket ID No. EPA-HQ-OAR-2013-0602 – Clean Power Plan

Dear Administrator McCarthy:

The Minnesota Department of Commerce (Commerce) and Minnesota Pollution Control Agency (MPCA) are pleased to submit the following comments on the U.S. Environmental Protection Agency's (EPA) proposed "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" rule (also known as the "Clean Power Plan") published in the *Federal Register* on June 18, 2014.

We applaud EPA's proposed rule approach, and believe it to be both good, and necessary, for the environment and the economy. While the proposal will not be sufficient to reduce emissions to fully address concerns associated with greenhouse gas emissions, it does represent a reasonable start for the power sector. Minnesota is proof that aggressive carbon emissions reductions from the electric power generation sector can be achieved while growing the economy, and we look forward to being a leader among states in addressing the requirements of the final Clean Power Plan.

As a state with an EPA-identified best system of emissions reductions, Minnesota will certainly continue its work to upgrade our electric generation system and reduce the carbon intensity of energy production. That said, we are concerned with certain aspects of EPA's rule, and had hoped it would have done more to put other states on the same clean energy path Minnesota has helped to develop. Instead, it appears as though the rule largely relies on clean energy leaders like Minnesota to make further reductions in carbon emissions to provide an overall level of national rule stringency while asking less of states with currently underdeveloped clean energy resources. Such a strategy may not take full advantage of the "low-hanging fruit" of carbon emissions reductions that remain available in many states, while seeking more aggressive reductions from states well-into their clean energy transition. The enclosed comments, though supportive of EPA's proposal, attempt to resolve some of these concerns.

We believe Minnesota is on a clean energy path that is generally consistent with EPA's plan, and clean energy efforts in Minnesota have already resulted in some 15,000 jobs accounting for over $1 billion in annual wages. However, EPA's plan is likely to result in job shifts within the energy sector. EPA should work with states to help provide clean energy training opportunities where appropriate.

We appreciate the opportunity to comment on the EPA's proposed Clean Power Plan. If you have any questions regarding the enclosed comments, please contact Bill Grant, with the Department of Commerce, at 651-539-1801 or bill.grant@state.mn.us; and J. David Thornton, with the MPCA, at 651-757-2018, or j.david.thornton@state.mn.us.

Sincerely,

Mike Rothman
Commissioner
Minnesota Department of Commerce

John Linc Stine
Commissioner
Minnesota Pollution Control Agency

JLS/MK:ld

Enclosures

cc: Janet McCabe, Headquarters, U.S. Environmental Protection Agency
Susan Hedman, Region 5, U.S. Environmental Protection Agency
Beverly Heydinger, Minnesota Public Utilities Commission
Bill Grant, Minnesota Department of Commerce
J. David Thornton, Minnesota Pollution Control Agency
Frank Kohlasch, Minnesota Pollution Control Agency

Minnesota's Comments on the Proposed Clean Power Plan
December 1, 2014

Stringency and Methodology of the Clean Power Plan Proposal

Minnesota supports the national stringency and general methodology of the Clean Power Plan

We support the proposed Clean Power Plan's effect of reducing nationwide carbon dioxide (CO_2) emissions 30% (from 2005 levels) by 2030. This reduction is complementary to Minnesota's current commitments to reduce CO_2 from its power generating sector, and we encourage the U.S. Environmental Protection Agency (EPA) to retain the stringency of its proposal.

Minnesota supports EPA's general approach to determining the Best System of Emission Reductions (BSER), and is pleased that EPA acknowledged Minnesota's efforts in implementing each of the "building blocks"—heat rate improvements at coal fired power plants, expanded use of natural gas combined cycle (NGCC) generation in lieu of coal-based generation, and growing renewables; expanded renewable energy (RE) generation and use of demand-side management tools like energy efficiency (EE) programs to reduce the demand for electricity generation of all kinds.

We also support the flexibility provisions of the proposal that allow states to determine their own best system of energy planning as they develop compliance strategies. This flexibility is especially important as it will allow states in their energy planning to balance CO_2 reductions with reliability and economic considerations.

Minnesota appreciates that EPA is considering multiple alternatives for the building blocks as it develops its final rule. While the provisions of the final rule remain uncertain, we believe that EPA's original proposal is reasonable and achievable for Minnesota, provided EPA:

- Incorporates the technical corrections identified in Minnesota's September 16, 2014, letter (see attachment 1);
- Ensures that, for compliance purposes, states compelling RE production in another state are able to use the energy produced; and
- Ensures that new, imported hydroelectric power may be fully counted for compliance purposes.

Minnesota will, of course, achieve the Clean Power Plan targets by utilizing a different building block combination than that identified by EPA, relying more heavily on the use of RE and less so on NGCC. Regardless, we support of this proposal.

Providing a rule framework that facilitates regional approaches to state planning is critical to the success of the Clean Power Plan. A regional approach for compliance with the Clean Power Plan will recognize the relationship between a state's responsibility to achieve emission reductions from the electric generation sector and the regional electricity market in which affected units participate. We strongly encourage EPA to ensure that the final rule removes any barriers to multi-state planning and enable efficient regional planning approaches.

At this time, we do have concerns regarding some aspects of the proposal – including certain aspects of BSER calculations, treatment of post-baseline actions for compliance planning, and strategies for interim target setting - and have provided comment on those and other issues below.

In EPA's Notice of Data Availability (NODA) (79 FR 64543), EPA sought comment on a number of additional issues identified by stakeholders in early comments on the proposal. Minnesota appreciates EPA's efforts to carefully consider all stakeholder concerns, and requests similar deliberation of Minnesota's comments.

Alternative Building Block Targets

Minnesota supports EPA's goal to increase the use of renewable energy in the U.S. Based on current requirements and energy plans, Minnesota expects to generate 28.5% of its electricity using renewable sources by 2030. Minnesota's recent renewable energy integration study conducted by GE Energy Consulting for Minnesota energy planners indicates that it is technically feasible to generate up to 40% of Minnesota's electricity from renewable sources (see attachment 2).

The Clean Power Plan's alternative RE proposal, however, would have a significant impact on Minnesota's final target without reasonable adjustments as noted below. Minnesota – already a clean energy leader in the U.S. – would be expected to reduce the carbon intensity from its base year emissions by more than half, and do so within little more than a decade. Minnesota believes that a 2030 final reduction goal of 700 lb/MWhr resulting from the alternative RE proposal could be problematic – this is the CO_2 emissions rate achievable by a new NGCC, but little else.

Minnesota believes the alternative RE approach would be more reasonable and better represent BSER if additional adjustments can be included in the final emission guidelines:

- EPA must incorporate the technical corrections identified in Minnesota's September 16, 2014 letter.
- EPA should ensure that new, imported hydroelectric power may be fully counted for compliance purposes.
- EPA should reconsider NGCC capacity factors for states, like Minnesota, with higher RE potential to reflect the role played by NGCC in backing up RE generation. Minnesota will further address this proposed reassessment of NGCC capacity in comments below.
- States like Minnesota, which have paid for RE located in other states, should receive full compliance credit. Minnesota rate payers rely on RE to reduce reliance on fossil fuel generation and should not be expected to bear additional compliance cost burdens for carbon emissions reductions they have already paid for.
- EPA should allow states to include new NGCC in compliance calculations, thereby expanding the pool of available mitigation options and lowering compliance costs.
- Finally, for reasons of burden-sharing, EPA should adopt a minimum performance level requirement for coal-fired EGUs commiserate with a 20% reduction in emissions intensity for coal. This value is about 1.75 lb/kWh. Minnesota recommends this in place of EPA's proposed reassignment of NGCC capacity to states currently without NGCC.

NGCC Capacity Factors Under the Alternative RE Approach

If EPA uses the Alternative RE approach in the final rule, where expected RE generation is substantially increased for many states in EPA's determination of BSER (and targets therefore made considerably more stringent, as indicated in comments above), the reliance on a 70% NGCC capacity in building block 2 target-setting calculations for Minnesota and other states with similar generation profiles should be reconsidered.

EPA's current assessment of NGCC in building block 2 may overlook the role NGCC units have in support of wind and solar power. Minnesota relies on NGCC units to provide energy during peak consumption periods, and in part as backup for wind energy. Minnesota is concerned whether our existing NGCC, run as baseload plants with capacity upward of 70%, could additionally fulfill their existing role in supporting RE generation and peak load service. With current RE generation of about 10,000 GWhr, it might be reasonably expected that with whatever role NGCC plays in backing up its wind resource, under the alternative RE approach that expects Minnesota's RE generation to increase to 18,647 GWhr, Minnesota's reliance on its existing NGCC capacity to back up RE will increase.

Minnesota recommends that if EPA finalizes the alternative RE approach, it re-visit NGCC capacity factors on a state-by-state basis to refine state targets. We encourage EPA to closely review comments from the Midcontinent Independent System Operator (MISO) (and all other independent system operators and regional transmission organizations) regarding actual utilization of NGCC for states and regions as it reconsiders NGCC capacity.

Transmission costs under the Alternative RE Approach

With current RE generation of approximately 10,000 GWh and Minnesota's current renewable energy standard (RES) requirements for future years, EPA's alternative RE goal is not an unreasonable projection of renewable potential for Minnesota, if production tax incentives for renewable energy remain in place, economic growth continues, and the cost of renewable energy continues to decline relative to the cost of other resources. Minnesota ratepayers have already made significant transmission investments to enable Minnesota utilities to reach the state's RES requirements. For the State to be able to reach the alternative RE target level of RE generation, an evaluation of additional transmission investment may be needed. Significant additions of renewable energy could require either additions of more transmission capacity, different configurations of transmission facilities, or both. If EPA finalizes the alternative RE approach, it should ensure that final assessment of building block 3 consider transmission costs.

Post-Baseline Considerations

EPA must better support early efforts to reduce carbon emissions for Clean Power Plan compliance

EPA should credit all emission reduction actions occurring after the 2012 base year. Failure to do so creates an incentive for states to delay emission reduction measures so they will "count" for plan compliance (thereby delaying actual reductions of CO_2) and is unfair to states and utilities with active, on-going clean energy programs. Additionally, EPA should allow states to recognize emissions reductions from existing (pre-2012) programs to the extent that these program measures continue to provide quantifiable emissions reductions.

Compliance Deadlines and Interim Targets—The 2020 to 2029 Glidepath

Minnesota supports EPA's proposed 2030 compliance deadline, but believes the interim goal approach should be modified

Achieving EPA's proposed final target will require significant shifts in generation as well as additional transmission. Minnesota believes that while aggressive, the year 2030 is an achievable compliance deadline, assuming EPA incorporates changes provided on page 1 of this document.

However, Minnesota believes the proposed interim goal requires reassessment. In its current form, the interim goal is too restrictive because the timing does not allow for orderly energy planning. The interim goal fails to account for the manner in which large energy generation shifts generally occur and is at odds with Minnesota's energy planning processes. The interim goal is too strict, and as a result limits Minnesota's flexibility in choosing how to meet the interim and/or final reduction goals.

EPA's integrated planning model (IPM) predicts Minnesota closing 1600 MW of coal-fired generation by 2030. To replace such large generation resources, Minnesota utilities will need to consider all types of generation. Such large generation shifts are not yet identified in utilities' current integrated resource plans (IRPs). The effort to accomplish those shifts includes generation resource planning, design, financing, permitting and construction, not only of generation, but potentially additional transmission lines and natural gas pipelines. EPA's alternative RE goal could require even further additional transmission investments – the nature of wind generation and Minnesota's load would require construction of transmission lines so that nighttime generation could be transferred to the east. If no longer able to "sink" energy to the east, we would likely be required to curtail more generation.

For a long-term average interim target whose compliance period begins in 2020, it will be difficult for states to achieve the emission performance required by EPA's interim targets set by EPA's building block assembly. Setting a stringent interim target that includes an average of emissions performance beginning in 2020 would then require states to over-control beyond the interim value to offset any year's emissions rates above the value – possibly controlling to a level even below the final target value. Because of this, states would essentially need to be achieving emissions rates close to the interim target by 2020. Minnesota has reduced the carbon intensity of its energy fleet substantially, but we began our efforts nearly 15 years ago; EPA's current interim approach affords us insufficient time to implement significant changes to Minnesota's electric generating fleet.

In Minnesota, achieving the final goal and shifting generation as described above will likely result in large "step changes" in emissions, not a gradual reduction as the proposed interim goals seem to assume. This step function of emissions progress must be determined in long-range planning that considers how investor-owned utilities will need to modify IRPs to help achieve Minnesota's final goal. These step changes and the long-term planning needed to produce them necessitate state-level involvement in the creation of any associated interim targets.

We recommend that in place of EPA adopting its own numerical value interim goal for each state, EPA should instead apply the structure it has adopted within the regional haze rule (40 CFR 51.308 (d)(1)) for ensuring reasonable progress. Under the regional haze program adopted by EPA, the state, not EPA, is responsible for establishing the reasonable progress goals as a part of its Regional Haze State Implementation Plan, and is directed to establish goals that represent progress without backsliding. The regional haze program allows the state to assess the cost of compliance, and then determine the rate of progress needed. The goals established by the state are not federally enforceable, but are considered by the Administrator and then approved when the Administrator evaluates the adequacy of the state's plan. Alternatively, or as a part of allowing states to set their reduction goals, an interim goal that reflects an average emissions rate from 2012 to the final goal would more appropriately take into account the timing of measures to be implemented to achieve final reduction goals.

In EPA's NODA, EPA requested comment on a plan for phasing in building block 2 on the basis of how quickly additional infrastructure improvements could be developed to support NGCC (79 FR 64552). Based on Minnesota's experience with its nearly-completed major transmission upgrades called CapX2020[1], some transmission projects could take nearly the entire compliance time period to complete. This further supports a rationale for allowing states to set their own interim targets as a part of their planning process, as states would be in a better position to assess state and regional infrastructure improvement impacts on interim compliance progress. This approach also fully recognizes state energy planning processes in Clean Power Plan implementation.

Minnesota strongly supports the use of state-identified interim targets, rather than the approach identified by EPA in its proposal. We understand, however, the concern that some states may fail to set a reasonable interim goal (or any goal at all). For such situations, EPA could rely on their proposed interim target approach as a "backstop" to ensure reasonable progress on a state-by-state basis.

If EPA is unwilling to adopt Minnesota's recommended approach, we would suggest that, at a minimum, EPA modify the 2020-2029 averaged interim target and instead identify a single-year interim target (e.g., 2025) level of performance. A reasonably set single-year target would avoid the problem identified above of having to offset performance above the interim target value with proportionate performance below the target value.

[1] http://www.capx2020.com/

Hydroelectric and Nuclear Power Generation Considerations

New hydroelectric power should be allowed to be included for compliance crediting in a state's plan

Minnesota utilities have entered into agreements to deliver Canadian hydroelectric power as a significant part of their resource mix. Minnesota expects that EPA's final rule will allow states to include expanded hydroelectric power in the compliance calculations. Expanded power could be achieved with additional capacity obtained through the development of new power at existing power facilities, or the purchase of previously unused Canadian power.

Minnesota agrees with EPA that hydroelectric power generation should be available for use in compliance determinations as a zero emissions energy source. Hydro is also able to quickly respond to changing wind and solar generation, and is a reliable source of power. The Department of Energy (DOE) is suggesting that the United States could increase hydroelectric power capacity by 15% by retrofitting existing dams with power generation; by allowing "new" hydroelectric power—that is, the expanded use of hydroelectric power in a state's compliance plan, EPA will also provide incentives for developing these small hydro generation projects. According to the 2012 Oak Ridge National Laboratory study conducted for the DOE, Minnesota has the potential of 186 MW of generation at existing dams that are currently without power[2].

Within the compliance period of this rule, Minnesota will also begin the planning process for replacing up to 900 MW of nuclear generation. It is important to allow states to consider expanded contracts of hydroelectric power from Canada as a means of replacing one zero-emitting generation technology with another. If EPA adopts its proposed alternative approach for renewable energy targets as described in this rule's proposal, Minnesota will have even more zero-emitting generation to secure. Minnesota recommends that EPA affirmatively state that hydroelectric power installed nationally and internationally post-2012 may be included in a state's plan.

Treatment of Nuclear Power Generation

States with existing nuclear capacity are penalized in the calculation of emission rate goals. Under EPA's approach, states with nuclear power are left with a more stringent emission rate goal relative to states that do not employ nuclear power because of EPA's inclusion of the 6% "at risk" generation factor in the calculation of state goals. We recommend that this factor be dropped in the determination of states' CO_2 compliance goals.

Renewable Energy

Minnesota's renewable energy leadership should be reflected in the State's goal calculation

Minnesota has led on renewable energy goals and laws since the early 2000s. In 2001 the Minnesota legislature enacted the Renewable Energy Objective (REO), which required electric utilities to make a good faith effort to ensure that at least one percent of the energy the utility provides to Minnesota consumers is generated by an eligible renewable energy source by 2005, and to increase this amount to 10 percent by 2015. In 2003 the REO was modified from a goal to a requirement for Xcel Energy, the largest electric utility operating in the State. The 2003 legislation also authorized the Minnesota Public Utilities Commission to establish a renewable energy credits trading program for the REO, whereby utilities could purchase certified renewable energy credits rather than generate or procure the renewable energy directly.

In 2007, Minnesota enacted the Next Generation Energy Act (NGEA). The NGEA created, among other programs, a Renewable Energy Standard (RES) that requires Minnesota utilities to acquire renewable energy equal to 25% of retail electricity sales by 2025 (Xcel Energy must reach 30% renewables by 2020). In 2013 a 1.5% Solar Energy Standard (SES) by 2020 was enacted for investor-owned utilities. The SES statute also includes a 10% solar goal for 2030.

[2] http://nhaap.ornl.gov/system/files/NHAAP_NPD_FY11_Final_Report.pdf

Minnesota's early action to spur renewable energy development prior to 2012 must be reflected in the State's interim and final goals. Minnesota's ratepayers have made significant transmission and RE facility investment to build the State's renewable energy portfolio to what it is today. This investment is seen in EPA's assumed RE level data in the alternative RE generation quantification approach: while the renewable energy resources available to Minnesota are similar to the natural resource conditions in our neighboring states, Minnesota's effective RE level under the alternative RE approach is 20 to 30 percent higher than the effective RE levels found for Minnesota's neighbors. To the extent that the effective RE levels and targets impact a state's interim and final goals, early adoption of RE through aggressive state policies should not result in a state's goal being made more stringent.

EPA must allow states to use renewable energy credits (RECs) like that provided by the Midwest Renewable Energy Tracking System (M-RETS) to track and account for renewable generation

Based on data from MISO, the M-RETS system tracks the amount of renewable energy that is actually delivered to the integrated transmission system. Each megawatt hour of renewable power produces a REC. Owners of RECs can use the RECs for various purposes, such as selling the RECs or complying with state RPSs. In any case, M-RETS allows each REC to be used only once, for a specified purpose.

The RECs may belong directly to the owner of the generation facility or to another entity that purchases the renewable power through a contract such as a power purchase agreement (PPA). Once the owner of the REC "retires" the REC in M-RETS for a specified purpose such as compliance with the Minnesota RES, the REC may not be used again. As such, M-RETS ties renewable energy production to a specific entity, no matter where the renewable energy facility is located.

Minnesota's current RES allows utilities to bank RECs for up to four years to allow utilities the practical flexibility needed to plan for the "lumpiness" of large renewable energy projects with long planning, development, and construction lead times. The four-year REC banking system also allows utilities to match variable renewable resources with variable load that typically occurs with fluctuations in weather, so that generation in excess of goals from a high wind year may offset generation deficits in a low wind year.

EPA must be clear in its final rulemaking how a state like Minnesota could rely upon RECs tracked in M-RETS, and whether any additional information or changes to the system would be required for Clean Power Plan compliance purposes.

EPA should make it clear that States that implement RE measures receive the credit, regardless of where the generation resource is located

EPA has included RE physically generated outside of Minnesota but "counted" under Minnesota's RES in their calculations of those other states' Clean Power Plan emission rate targets. EPA should include language in its final rule making clear that states compelling newly built (post-proposal) renewable generation receive credit towards their compliance demonstration. The MPCA's understanding of the proposed rule's treatment of RE resources comes from *State Plan Considerations TSD*, which indicates that a "state that implements the measure – i.e., end-use energy efficiency and renewable energy regulations or programs, or an emission limit that addresses out-of-state generation – claims the avoided CO_2 emissions, regardless of where they occur." Explicitly stating in rule language that States (and the retirement of the associated RECs) receive credit is necessary for stable RE planning.

To meet this goal, Minnesota recommends that EPA continue to use this approach, by allowing the utility to count toward Minnesota state plan compliance the actual RECs from renewable energy production that the utility retires in M-RETS toward Minnesota's RES, regardless of where the RE facilities are located. This system also allows utilities to count portions of production from a renewable facility toward more than one states' RPS; however, each REC associated with

one MWh of renewable energy production may be counted only once. As a result, a system such as M-RETS allows for reasonable flexibility and verifiable compliance.

The most cost-effective location for renewable energy may be in another state; under M-RETS, utilities may claim ownership of such renewable energy only by ownership of the generation facility or by contract such as a PPA. Because M-RETS tracks (1) the amount of renewable energy delivered to the interstate transmission system and (2) the amount of renewable energy that the utility retires for each state, and since RECs may be used only once, Minnesota recommends that M-RETS or an equivalent system be used for state plan compliance.

Not only would this approach allow for the most cost-effective approaches for state plan compliance, allowing continued use of a system that is already in place for RPS compliance would remove the current unintended effects that uncertainty about state plan compliance is having in delaying cost-effective renewable energy additions to utility systems. For example, a multi-state utility recently delayed any addition of 300 MW of wind that was shown to be cost-effective because it was not clear how the location of the wind facilities would affect plan compliance in various states.

Voluntary green power programs should not be counted toward utility compliance with the Clean Power Plan
Almost all Minnesota utilities offer some form of voluntary program whereby ratepayers may pay a premium to source their energy consumption from renewable generation to go above and beyond the minimum requirement set by the state. To ensure the RE sought by participating ratepayers is in addition to that already compelled by the State, Minnesota does not allow green pricing RECs to count toward the State RES. Minnesota utilities must create separate REC retirement accounts to avoid counting green pricing RECs toward the utilities' MN RES or other state's RPS and green pricing programs. Similarly, if it were possible that the renewable power for which customers were paying a premium would have been acquired by the utility anyway for compliance with the Clean Power Plan, this would undermine the main attraction of green pricing programs.

EPA should ensure that the final rule includes language clarifying treatment and compliance crediting of waste-to-energy (WTE) facilities
Minnesota believes that when EPA calculated RE already being generated in a state, they counted all of the electricity from municipal WTE facilities as renewable, making no effort to separate or discount the electricity generated. We encourage EPA to provide clarifying language regarding the quantification of eligible electrical output from these facilities.

Energy Efficiency

Credit for Emissions Reductions on EGUs outside of Minnesota
Under Minnesota Statutes §216B.241 subd. 1c, all Minnesota electric utilities are subject to an annual energy savings goal of 1.5% of annual retail energy sales, excluding sales to customers that have opted out of utility-administered EE programs.[3] Many utilities have one or more qualifying EGUs located outside the state. Thus, end-use efficiency measures within the Minnesota service territories of these utilities may result in emissions reductions at EGUs located outside of Minnesota. Nonetheless, the full savings realized by these EE measures are credited to the utility and applied toward their 1.5% savings goal. For compatibility with existing state law and because the incentives and related program expenses incurred by the utility are wholly funded by Minnesota ratepayers, we feel that Minnesota should receive full credit for savings realized at out-state EGUs under 111(d). Such treatment of EE savings would be consistent with expected treatment of out-of-state RE generation compelled by Minnesota.

[3] See Minnesota Statute 216B.241, Subdivision 1a. for details regarding large customer facility exemptions from CIP.

For reasons of equitable burden sharing among states for goal setting and expedited emissions performance, EPA should accelerate the rate at which states ramp up to EE goals of 1.5%

Minnesota's experience has shown that EE programs can be developed and intensified relatively quickly. The rate of increase in energy savings in Minnesota's electric power system went from 0.8% to a required 1.5% between 2007 and 2010. EPA should consider similar ramp-up rates for states that have yet to achieve a level of 1.5% energy savings.

Data Collection and Reporting Requirements

Minnesota's automated software solutions for EE data management and reporting, developed to enable achievement of State policy goals, are also conducive for enabling effective data management and reporting under 111(d). We urge EPA not to designate the use of specific software that would undermine the work that we have done to improve the accuracy and efficiency of EE data collection in the state. While minimum reporting requirements should be expected for data collection and reporting, we encourage EPA to review existing state reporting programs to help set such minimum requirements. We are happy to provide EPA with more information on ESP® (also discussed in attachment 3) or a demonstration if it would be helpful.

Gross vs. Net Savings

As EPA is aware, states generally require that EE savings be expressed as net savings, gross savings, or both. Gross savings reflect the savings realized by the efficiency improvements irrespective of the customer's motivations for making the improvement. Net savings represent the savings achieved by the program after subtracting out "free-riders" (customers that would have made the EE investment without the influence of the program), sometimes adding in market "spillover" effects to non-participants, and removing the influence of other programs or exogenous factors. While the definition of net savings is commonly understood, the factors included in net savings evaluations vary by state. This makes it difficult to compare net savings across states. Net savings are also very sensitive to the evaluation methodologies and input assumptions employed by each evaluator. In contrast, gross savings are relatively straightforward to evaluate. Technical Reference Manuals and other resources provide standard methodologies for calculating gross savings, and standard protocols such as the International Performance Measurement and Verification Protocol are commonly used across the industry to measure and verify gross savings. For these reasons, Minnesota strongly encourages EPA to require reporting of gross savings under 111(d).

If desired, EPA could require reporting of "adjusted" or "verified" gross savings under 111(d). Adjusted gross savings represent the gross savings achieved by a program after installation and operational information on the EE measures are collected through site visits, sub-metering, billing analysis, customer surveys, and other techniques through a third-party impact evaluation. If evaluated correctly, adjusted gross savings are the best estimate of actual physical savings realized. Although Minnesota does not currently require third-party impact evaluations, we are open to this approach under 111(d) as long as the requirements do not entail excessive Evaluation, Measurement and Verification (EM&V) costs. We suggest that EPA cap EM&V costs at 5% of total EE spending in determining EM&V requirements and guidelines.

Inclusion of non-utility EE

EPA should encourage states to develop a clear path for inclusion, crediting, and administrative review and oversight of non-utility-delivered energy efficiency activities providing emissions reductions included in state plans. This may include energy savings performance contracts, low-income weatherization programs, industrial energy efficiency and other privately contracted and delivered energy efficiency historically unaccounted for in ratepayer and state programs. EPA should afford great deference to state energy efficiency programs and policies and allow states to credit energy efficiency programs and policies that utilize EM&V protocols and standards (as outlined in attachment 3). EPA should acknowledge and support state program competency in energy program design and delivery. State energy efficiency program experience, energy savings goals, and structures have varied based on state circumstances.

Additional Considerations from the Notice of Data Availability

EPA published a NODA on October 30, 2014, seeking specific comment on a number of additional proposals and/or issues identified in the original proposal. We must note our frustration with the late-issued NODA, which provided several significant rule alternatives for consideration, but with no additional time for review/comment, and no additional data provided to assist States in their review. Without additional time and data to review NODA alternatives, it is difficult for Minnesota to fully understand and address its impacts at this time. Though certain items in the NODA are addressed in comments above, Minnesota addresses some additional proposals below.

EPA should consider alternatives to the 2012 base year only for anomalous units

The NODA solicits input regarding whether a different single data year or average of a combination of years should be used to calculate a baseline for use in state goal calculations. Minnesota believes that 2012 is generally an appropriate base year, and should remain the presumptive base year for most units in most states. For units whose operation in 2012 was anomalous, states should select an appropriate three-year average for use in baseline calculations. Providing the opportunity for states to select years would better ensure the use of data more reflective of the unique circumstances of these particular units. Requiring such data to be in the form of a three-year average would lessen the likelihood that a state could simply select the highest-emitting year for a particular unit. This approach could address, for Minnesota the concern with Sherco Unit 3 identified in our September 16, 2014 letter, and may address concerns for other units whose 2012 operation was also anomalous. EPA should issue an additional NODA or supplementary proposal providing this option, and allowing states the opportunity to submit appropriate three-year average baseline information for anomalous units. Final goals would incorporate data for these anomalous units.

EPA should not assign a CO_2 value to RE and EE in order to re-assess building blocks 3 & 4

In the NODA, EPA discusses some stakeholders' interest in assigning a CO_2 value to RE and EE (79 FR 64552) and suggests alternative means to determine a value. EPA first asks for comments on the assumption that RE and EE replace fossil generation, either proportionately, or fossil steam first.

It appears to be erroneous to assume that additional RE and/or EE will replace in-state fossil generation directly; Minnesota has recently completed a study to determine how to integrate additional renewable energy into its current electricity generation system, up to 40% of all generation. The study, prepared for Minnesota by GE Energy Consulting, is provided in attachment 2. This study indicates that for Minnesota, additional RE will not simply displace in-state fossil generation (coal and gas) but rather, will displace resources on the margin, including imports from outside Minnesota. Given this, it is reasonable to assume that each state will be different, and thus subject to different impacts or effects of adding new RE generation, or EE savings, to a state's mix of generation. In order to appropriately assign a CO_2 value to RE and EE, a state would need to know what resource was at the margin at the time (which involves hour to hour variations) the RE or EE energy was created, or EPA would have to come up with some marginal emissions factor. Very few studies exist on marginal emission factors in the US, and EPA would likely have to conduct foundational research into this matter. Given the time constraints associated with the Clean Power Plan and the complexity of research needed to accurately modify the building block 3 and 4 calculations, Minnesota recommends that EPA treat RE and EE as originally proposed.

Additional Considerations on the Rate to Mass Translation Notice of Additional Information

EPA published a notice on November 13, 2014, detailing a possible method for translating emission rate-based CO_2 goals to their mass-based equivalents. The late issuance of this information makes it difficult to fully analyze EPA's suggested method; however, we note our general interest in a workable method for translating rate-based goals to mass-based goals. A mass-based goal appears to be able to simplify much of the compliance work associated with this rule – particularly if states were to choose to implement trading programs (single and/or multi state) for compliance. However, we are concerned that the method identified by EPA in its November 13 notice seems to increase the stringency of

Minnesota's final target from the rate-based goal identified in the original proposal. We believe that the rate-based target would require an approximately 40% reduction in CO_2 emissions, while the mass-based method identified by EPA would result in a 50% or greater reduction. This discrepancy in stringency resulting from EPA's translation methodology is of considerable concern for Minnesota, and likely for many states. If approvability of mass-based targets in state plans is dependent upon some level of adherence to EPA's calculation method, we believe that the mass-based approach could simply cease to be a viable option for many states – thereby eliminating much of the flexibility upon which success of EPA's Clean Power Plan is based. EPA should either be very flexible in considering state methodologies for rate-to-mass target calculations in its plan review process, or should simplify its methodology and ensure that it results in equivalent stringency between the two approaches.

State Plan Considerations

Initial state plan submittal procedures

Multi-state plans and quantifications

EPA's proposal (70 FR 34915) indicates that only one multi-state plan would need to be submitted on behalf of all participating states. Please clarify expected procedures for initial (June 30, 2016) submittals. Will states expecting to participate in multi-state plans be expected to submit individual preliminary plans, or joint plans? Please also clarify EPA's expectation regarding the "initial quantification of the level of emission performance," and indicate whether EPA expects different levels of analysis based upon whether a state expects to participate in a single or multi-state plan. For a multi-state plan, state-level quantifications of emissions performance may be difficult to produce by mid-2016 (or ever, depending on whether a region were to create a trading program or other system where performance is dependent upon regional operations that may vary throughout the compliance period). Minnesota recommends that EPA require one (joint) submittal on behalf of all states expected to participate in a multi-state plan, for both initial and final plan submittals, and that initial quantifications of the level of emission performance be provided on an overall (all states participating in a given multi-state plan) basis, rather than a state-level basis.

Projections of future CO_2 emissions

Recognizing that this rule has a very long implementation period, what type of documentation does EPA believe necessary for supporting states' projections of future CO_2 emissions? EPA should either provide guidance, or allow states to use that data most reasonably available to a state. Minnesota would recommend that EPA not require the use of IPM modeling for state-level emissions projections.

Procedure for review of initial plans

According to the preamble (70 FR 34915), if EPA determines that the initial plan does not meet the guidelines [identified in the rule language], EPA will notify the state by letter, within 60 days, that the agency cannot approve the state's initial plan as submitted. EPA believes this approach is authorized by, and consistent with, section 60.27(a) of the implementing regulations.

EPA's intent for the initial plan approval/disapproval process is unclear. Under 40 CFR 60.27(a), EPA may extend the period for submission of any plan or plan revision. Is EPA suggesting that the 60-day letter will serve as some sort of extension of the period for submission of the initial plan, or that it would serve as EPA's official proposal for disapproval, thereby triggering EPA's obligations to propose its own plan for a State (Section 60.27(c))? EPA's proposed rule language Section 60.5760(b) suggests that EPA's 60-day letter will find that the initial submittal does not meet the plan requirements, which would suggest EPA considers the letter as a disapproval. However, Section 60.27(b) indicates that EPA will propose a plan for approval or disapproval, suggesting a formal notice and comment period. Please clarify EPA's procedure for disapproved initial plan submittals, and indicate where States will be afforded the opportunity for formal notice and comment of such disapprovals, prior to EPA's promulgation of its own plan for a State.

Changes between initial and final plan submittal
Please provide additional detail regarding EPA's process approach for States whose initial strategies may change between initial and final plan submittal. For example, a failure of a Memorandum of Agreement for a multi-state plan results in a State choosing to withdraw and pursue a single-state plan after the single-state plan submittal deadline passes. Would EPA automatically consider the State to have failed to submit its plan, would it find the State deficient only after the multi-state deadline passed, or does EPA intend to provide some mechanism authorizing such a change in strategy in its final rulemaking? For a State that initially intended to submit a single-state plan but which, after June 30, 2016, chooses to instead participate in a multi-state approach, must they complete a formal revision of their initial plan submittal to indicate the revised approach?

Plan Review Procedures
Minnesota applauds the flexibility in choosing compliance strategies provided by EPA's proposal; however, the very same flexibility can potentially result in significant uncertainty, and even disparate treatment, for regulated entities, including states and affected facilities. Plan approvals and disapprovals will, presumably, occur at EPA regional office level. Without detailed central guidance and direction regarding approvable plan elements, similar compliance strategies could be viewed differently amongst different EPA regional offices. EPA must ensure consistent plan review across all regions in order to provide regulatory certainty to all stakeholders.

Additionally, please clarify the approval authority for multi-state plans that cross EPA regions. Though geographic proximity is not a requirement for a multi-state plan, it is likely that many, if not most, multi-state plans will include nearby states in similar ISO/RTO systems. Minnesota and the four states it borders are a part of MISO, yet cross three EPA regional office boundaries.

Stakeholder proposals – model trading rule
EPA invited comments on key stakeholder proposals, including the proposal that EPA should put forward a model rule for an interstate emissions credit trading program that could be adopted by states wanting to use such a program for its plan. Minnesota supports such a proposal, and recommends that EPA develop a model trading rule that states could incorporate by reference as a part of its plan, and automatically be included in a multi-state trading program. Such a program would likely minimize costs of compliance by allowing the most efficient reductions to CO_2 emissions to be selected for a region. If such a rule were developed by EPA, it should clarify whether states incorporating by reference would be considered subject to single or multi-state plan requirements.

Compliance periods/increments of emissions performance/ Reporting requirements/anti-backsliding
Section 60.5740(a)(3)(iii) of the proposed rule language indicates that for the interim plan performance period, state plans must identify the emission performance levels anticipated under the plan during "each year 2020 through 2029." Section 60.5775(c)(1) indicates that the state plan must include increments of emissions performance within the interim performance period for "every 2-rolling calendar years…" Please clarify whether EPA means for state plans to identify a yearly, or a rolling 2-year average performance level.

Minnesota does not necessarily object to the inclusion of annual or rolling two-year average performance levels in the state plans. The identification of such levels can be a useful tool in planning, and can help states and EPA to better manage compliance timelines when dealing with the long implementation deadline of the Clean Power Plan proposal. However, the long implementation period makes it difficult to produce precise and accurate annual performance projections – particularly when compliance with Clean Air Act requirements must also align with the complexities of energy planning. Annual (or rolling two-year) performance levels must be considered estimates for planning purposes only. The state reporting requirements identified in §60.5815 make the performance levels identified in state plans essentially binding, because states whose emission performance is greater than 10 percent in excess of projected plan

performance must specify/take corrective actions to be taken to ensure required interim plan performance. Minnesota believes such annual requirements to be unnecessarily onerous and unrealistic, particularly when dealing with such long-term implementation periods. If EPA means to establish some binding mid-course performance requirements (in addition to the interim targets it proposes), a more reasonable approach would be to require states to identify the average performance expected by, say 2025 (midway through the implementation period), and submit a mid-course review evaluating the state's performance up to that point and requiring corrective actions if needed.

Records retention

On page 34914 of the preamble, EPA states that it is "proposing that state plans must include a record retention requirement of ten years." Page 34855 of the proposal, however, contains proposed rule language, and states in section 60.5810(d) that "A state must keep records at minimum for 20 years." Please clarify.

Guidance/templates

EPA requests comment on whether to develop guidance for a number of topics: enforceability considerations related to requirements in a state plan for entities other than affected EGUs; evaluation, monitoring, and verification of renewable energy and demand-side energy efficiency programs and measures incorporated in state plan; tools and methods for projecting emission performance in state plans; and the inclusion of non-BSER emission reduction methods (such as electricity transmission efficiency improvements or the use of new NGCC units) in state plans.

Minnesota requests that EPA develop guidance for all topics identified. However, guidance must be timely, and made available for states as they begin to develop their state plans. EPA has often delayed guidance related to State Implementation Plan development to shortly before, or even after, the required submittal deadline, leaving States in a position of having to decide between developing and submitting plans that may be inconsistent with pending EPA guidance (and risk disapproval of said plans), or delaying plan development and submittal and risking a finding of failure to submit by EPA. EPA must ensure that its guidance – particularly guidance that will be necessary for states to develop federally approvable plans – is completed and made available to states early in the planning process.

Environmental Justice and Equity Considerations

The effects of climate change can be more pronounced on lower-income and urban residents. Higher summertime temperatures and extreme heat events may lead to increased illnesses, such as heat stroke, and worsening of respiratory disease, cardiovascular conditions, and other illnesses. Heat island effects can make such situations even worse in urban areas. Lower-income Minnesotans and the elderly, who often have less ability to get relief from extreme heat, can be at even greater risk. We applaud EPA's proposal, and its efforts to address the significant effects of climate change, and strongly encourage EPA to consider these effects on lower-income and urban residents as it develops a final rule. The final rule should consider and seek to limit additional burdens to lower-income communities and people of color, and require state plans to address such concerns.

Attachment 1

Minnesota Pollution Control Agency

520 Lafayette Road North | St. Paul, Minnesota 55155-4194 | 651-296-6300

800-657-3864 | 651-282-5332 TTY | www.pca.state.mn.us | Equal Opportunity Employer

September 16, 2014

U.S. Environmental Protection Agency
EPA Docket Center (EPA/DC)
Attention: Docket ID No. EPA-HQ-OAR-2013-0602
1200 Pennsylvania Avenue NW
Mail Code: 28221T
Washington, D.C. 20460

RE: Docket ID No. EPA-HQ-OAR-2013-0602

To Whom It May Concern:

The Minnesota Pollution Control Agency (MPCA) is pleased to submit the following comments on the U.S. Environmental Protection Agency's (EPA's) proposed "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," rule (also known as the "Clean Power Plan") published in the *Federal Register* on June 18, 2014.

The MPCA applauds the EPA's proposed rule approach, which closely matches Minnesota's policies and programs that have been in place over the last two decades and have reduced emissions of greenhouse gases from the electricity generating sector. The proposed rule addresses the critical need for carbon regulations to protect citizens, the environment and further development of a clean energy economy. Minnesota is proof that aggressive carbon emissions reductions from the power sector can be achieved while growing the economy, and we look forward to being a leader among states in addressing the requirements of the final Clean Power Plan.

Enclosed please find the MPCA's initial set of comments, focusing on important technical issues and data corrections for the proposed rule. The MPCA's initial comments address the following issues:

1. The MPCA requests certain corrections to electric generating unit operating status/characteristics used in calculating Minnesota's goals.
2. The MPCA requests clarification of the definition of affected units regarding the treatment of biomass-fired units.
3. The MPCA requests that EPA provide all states with the mass-based calculation of the state goal.
4. The MPCA requests that EPA issue a Notice of Data Availability prior to rule finalization that provides final targets and any necessary data corrections.

We plan to submit additional input on the proposal before the comment period closes. Because potential changes to technical data associated with Minnesota's affected units may influence additional comments on the Clean Power Plan proposal by the MPCA, we respectfully request an initial response to the enclosed comments as soon as possible.

The MPCA appreciates the opportunity to comment on EPA's proposed Clean Power Plan. If you have any questions regarding the enclosed comments, please contact David Thornton at 651-757-2018, or j.david.thornton@state.mn.us.

Sincerely,

John Linc Stine
Commissioner

JLS/MK:vs

Enclosures

cc: David Thornton, MPCA
Frank Kohlasch, MPCA

Technical Comments/Corrections for Proposed Clean Power Plan, Docket ID No. EPA-HQ-OAR-2013-0602

1. **The MPCA requests certain corrections to EGU operating status/characteristics used in calculating Minnesota's goals**

Northern States Power Minnesota (Xcel Energy)—Sherburne County—Unit 3—ORIS 6090

This 938 MW (nameplate capacity) coal-fired electric generating unit was out of service during the entire calendar year 2012 due to an explosion in 2011 in the turbine as the unit was returning to service after an outage. The unit was off line for about 2 years while repairs were made, and did not return to full service until January 2014. Minnesota will continue to rely on generation from this unit through the duration of the planning period for this rule and beyond. We believe that this unplanned outage makes the starting assumptions for coal-fired generation in Minnesota atypical, and requires that the baseline conditions for Minnesota be modified to include generation from this unit.

We believe that the average generation from 2009 to 2011, the three years prior to the explosion, is the best approximation of likely generation at Sherco Unit 3 in the year 2012, that is, 5,492,640 MWh releasing a total mass of 5,775,175 tons of CO2, as calculated from the monthly data reported to the CAMD database for this unit. We believe that this three year average reasonably approximates the amount of coal generation that might have occurred at Sherco 3 in 2012; the selection of these years reflects generation during the recession (2009) as well as the increasing reliance on wind generation by Xcel to meet its renewable energy generation required by Minnesota statute. Since reaching full capacity in January 2014, the unit has operated at an average monthly load of 469,000 MWh, which represents an annual average generation of 5,630,000 MWh. The MPCA's recommendation thus is a slightly conservative but reasonable approximation of likely 2012 generation at Sherco 3.

The MPCA recognizes that the EPA would likely be interested in "balancing" the assignment of generation at Sherco 3 by eliminating generation elsewhere. It would not be correct to simply assume that Sherco 3 generation could be replaced by adjusting generation at other Minnesota coal plants, or to remove generation from combined cycle plants in an effort to "rebalance" generation. Xcel Energy responded to an inquiry from Minnesota's Department of Commerce, the state authority charged with reviewing electric utility rate requests:

> "...Given the dynamic nature of generation systems and the need to make multiple purchase decisions instantaneously in order to respond to load variations, it is impossible to manually determine what energy source was deployed in place of an out-of-service plant..."
>
> Xcel Energy Response to Department of Commerce Information Request No. 125, Docket No. E002/GR-12-961 (copy attached)

The MPCA has reviewed generation Xcel's EGUs that operated in Minnesota during this period to determine if the units operated at higher rates than otherwise might have occurred with Sherco 3 online. Data from CAMD is displayed below in two graphs: Xcel-owned generation during this period (Figure 1), and generation at the Sherco plant itself (Figure 2). There is no discernable trend overall from all Xcel units (coal and gas), nor at Units 1 and 2 at Sherco.

EPA may be faced with conducting modeling to address potential similar issues with EGUs in other states. As result, if the EPA believes that generation needs to be adjusted, the MPCA suggests that the EPA conduct an *ex post* modeling exercise using an electricity system dispatch simulation model to evaluate which generation resources would be pushed out of the dispatch order if Sherco 3 had run in 2012, and adjust all generation accordingly. Minnesota does not have the capability to conduct this type of modeling.

Regardless, Minnesota is requesting that the EPA modify its calculation of Minnesota's 2012 baseline conditions to include generation at Sherco 3.

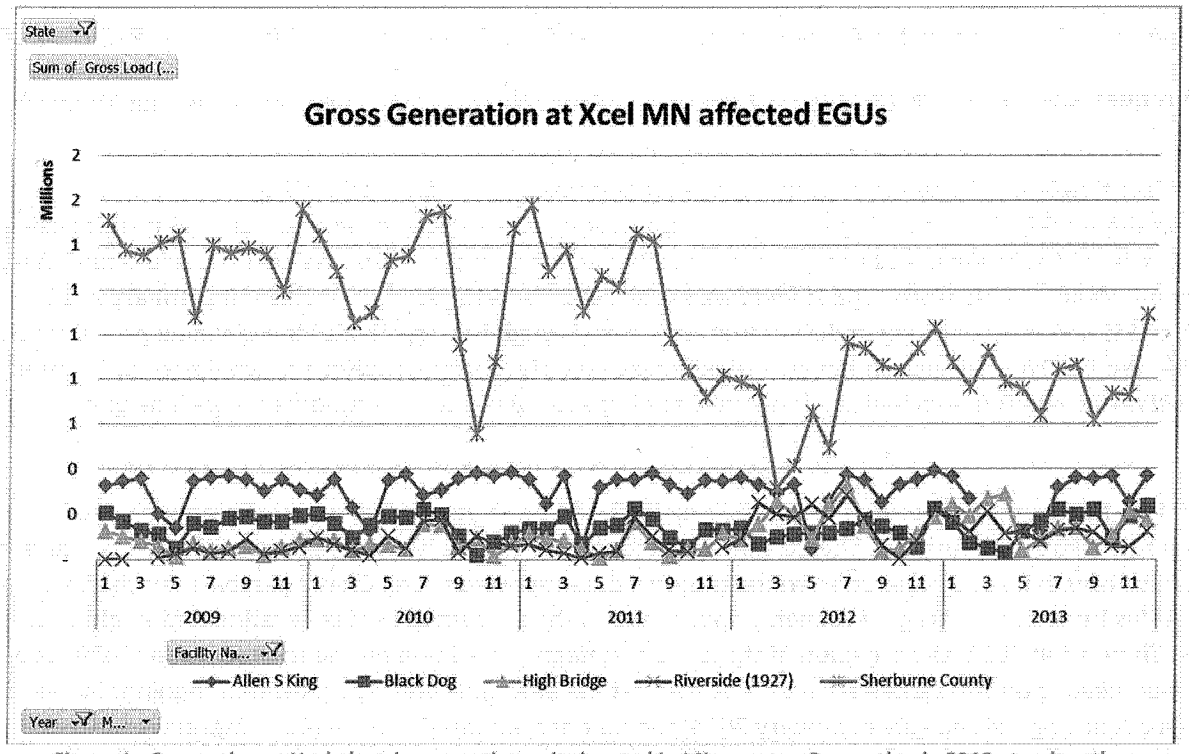

Figure 1. Generation at Xcel electric generating units located in Minnesota. Generation in 2012 at units other than Sherburne Countyoperate at typical generation capacity during the outage of Sherco Unit 3.

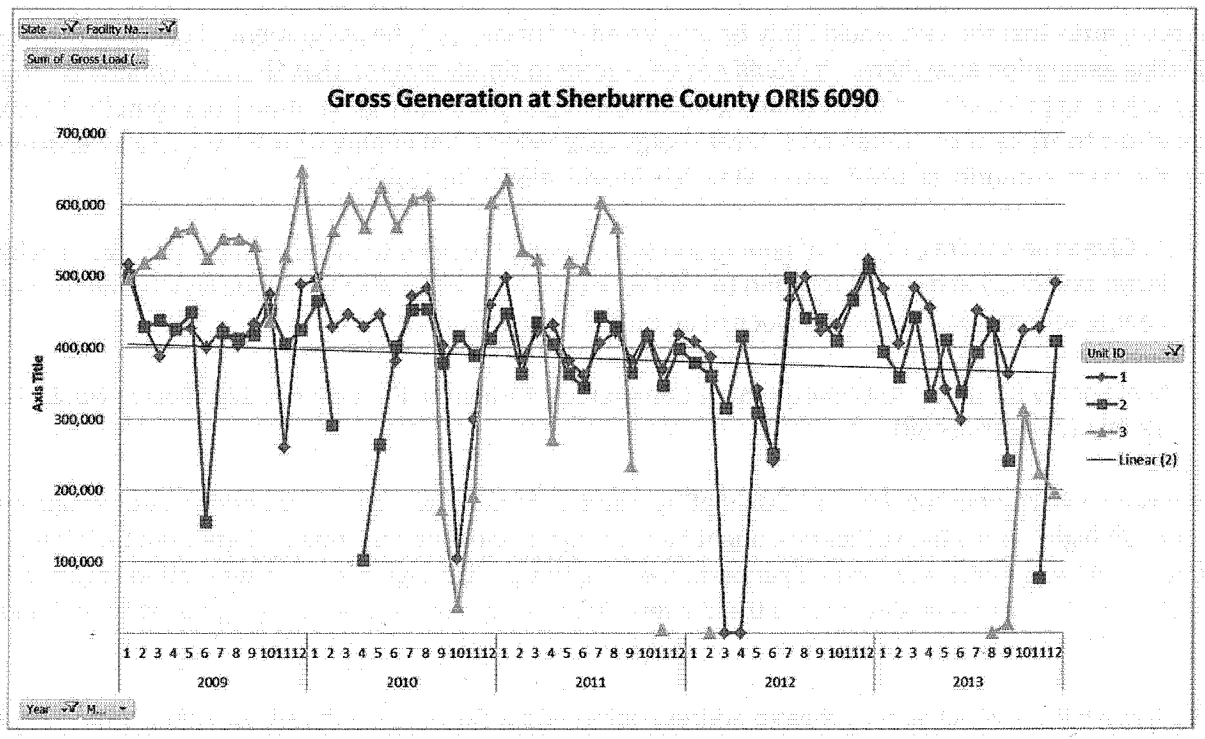

Figure 2. Generation at Sherburne County. Generation at Units 1 and 2 during the year were far below average during the first half of the year, then above average the second half.

Mankato Energy—ORIS 56104

Mankato Energy has a current capacity of a maximum of 375 MW at 6 degrees F. The nameplate capacity reported to EIA of 530 MW is due to the large capacity of the unit's steam turbine, if the facility had been constructed with all components. At this time, the steam turbine portion is oversized as the facility has only one combustion turbine and one heat recovery steam generator (HRSG).

The actual capacity of 375 MW is made up of 295 MW of combined cycle output with 80 MW of peaking power developed in the HRSG by employing duct burners. The existing Mankato Energy Center consists of one Siemens 501FD combustion turbine generator, one Nooter/Erikson HRSG, a Toshiba TCDF 40L steam turbine generator, and other ancillary equipment. In order to be able to generate up to 530 MW of power as the name plate capacity states, additional components must be installed at the unit. Because the plant was, and continues to be physically unable to generate 530 MW, the EPA should revise its presumption of the potential generation capacity for this unit to 375 MW.

Hutchinson Plant #2—ORIS 6358—Generators 2 and 3

In the EPA's preamble (*79 FR 34892)* the EPA states that state goals reflect the EPA's quantification of CO2 from affected units. Hutchinson Plant #2 does not meet the criteria of an affected unit because its average annual operation has been below 219,000 MWh. These units have never operated at or above this threshold. These units should be removed from the EPA's list of affected sources. Accordingly, the NGCC capacity in MN should also be revised to remove this EGU.

2. The MPCA requests clarification of the definition of affected units regarding the treatment of biomass-fired units.

The EPA must also clarify the definition of affected units in two important ways. First, the EPA states in the preamble that it is its intent to adopt the rule "...that in all other respects would meet the applicability criteria for coverage under the proposed GHG standards for new fossil fuel-fired EGUs" (79 FR 1430; January 8, 2014)." 79 FR 34854 However, the proposed rule fails to include a provision similar to that included in the 111(b) new source rule exempting a steam generating unit combusting fossil fuel for less than 10% of its heat input during any 3 consecutive years.

Second, the EPA treats biomass units as carbon-neutral resources for goal-setting purposes, by including their MWh of generation in the denominator of the formula in Building Block 3, but including no CO_2 emissions in the numerator for these units. The MPCA is concerned however, that in compliance, the EPA implies that biomass would not be treated as a carbon-neutral resource, since it refers to the EPA's *Biomass Accounting Framework* for 111(d) plan development where the methodology describes adjusting top-of-stack biogenic CO_2 emissions based on the particular feedstock and location. The EPA acknowledges that in the review of the Framework, the Science Advisory Board indicated that biomass cannot be considered "...carbon neutral *a priori,* without an evaluation of the carbon cycle effects related to the use of the type of biomass being considered." 79 FR 1446.

As a result, it appears that states are, in effect, penalized in the goal setting formula for having biomass plants. Treating such plants as carbon neutral (i.e., not including those plants' CO_2 emissions) in the goal setting formula makes the goal more stringent, while treating as non-carbon neutral for goal compliance then discounts the use of biomass for goal achievement. Whether the EPA intends for biomass to be considered a carbon-neutral energy source or not, it should provide regulatory consistency in its treatment of biomass generation and not inadvertently penalize states with biomass generation.

The MPCA encourages the EPA to treat biomass units consistently in both target setting and target compliance calculations, and to ensure that final rule language includes applicability criteria referenced in the proposed rule preamble.

M L Hibbard--ORIS 1897-- Unit 3 and Unit 4

The MPCA believes that the biomass units at Minnesota Power's M L Hibbard station met the definition of affected units in 2012 and were mistakenly not included in Minnesota's affected units inventory. The MPCA believes that the EPA incorrectly excluded the Hibbard units from its evaluation of affected units because they burn wood as a "primary fuel." However, even if the EPA finalizes rule language (referenced above) providing an exemption for steam generating units combusting fossil fuel for less than 10% of their heat input during any three consecutive years, the units at Hibbard would not meet such an exemption, and should therefore be included in Minnesota's inventory of affected units and considered in Minnesota's goal calculation.

Minnesota Power's Hibbard plant Unit 3 at 35.3 MW and Unit 4 at 37.5 MW were constructed in 1949 and 1951 respectively as coal-fired power boilers. Minnesota Power re-commissioned the units, which are now burning wood and coal as cogeneration units, providing steam to the papermaker located adjacent to the Hibbard plant in Duluth, Minnesota and electricity to the grid.

The MPCA has evaluated the characteristics of this facility in order to determine if the EGUs become subject to the rule under the proposed definition of an affected unit. Each unit has a capacity to burn fossil fuel (coal and natural gas) at a steady state rate greater than 250 mmbtu/hr alone or in combination with wood, was constructed for the purpose of providing more than 1/3 of its electric output and more than 219,000 MWh to the utility distribution grid. In the baseline year 2012, coal provided approximately 28% of Unit 3's heat input, and 20% of Unit 4's heat input. Hibbard's title V permit does not contain federally enforceable limits to restrict the amount of fossil fuel the units are allowed to combust, nor the amount of electricity sold such that the units are not considered EGUs.

Even with a revised rule definition to allow up to 10% of fossil fuel for startup and combustion stabilization, the MPCA believes that fossil fuel emissions and generation for these units should be included in Minnesota's inventory of affected units, as they are burning fossil fuel in excess of the EPA's apparent intended exemption.

3. **The MPCA requests that the EPA provide all states with the mass-based calculation of the state goal.**

The EPA's proposal currently allows states the option to either adopt the EPA-provided rate-based form of the emissions goal, or to calculate a translation of the rate-based goal into a mass-based goal. If a state choses to use a mass-based goal, it's plan must demonstrate that its mass-based approach achieves the equivalent stringency to the rate-based goal set by the EPA. The state-by-state calculation of a rate-based approach to a mass-based approach presents unnecessary complication and inconsistency state goal-setting, and results in regulatory uncertainty on the part of states and affected utilities, who must await EPA approval to determine whether their goal calculation is sufficient. The EPA could avoid such difficulties by providing each state with the mass-based emissions goal, providing the states with the substantive opportunity to provide comments and corrections on the mass-based goals, as they have with the rate-based goals.

4. **The MPCA requests that the EPA issue a Notice of Data Availability prior to rule finalization that provides final targets and any necessary data corrections.**

The MPCA expects the EPA to make technical corrections and modifications to the proposed rule based, in part, on public comments received. The EPA may also make more fundamental changes to the building block methodologies as a result of public comments. Because such changes may result in modified goals for states, the EPA should issue a Notice of Data Availability (or multiple notices, as needed), providing states the opportunity to review and provide comment on the changes to the state rate and mass goals, prior to rule finalization. The EPA used a similar approach with the Cross-State Air Pollution Rule, which helped states in their compliance planning and provided additional quality-assurance to the rule's technical elements.

Docket No. E002/GR-12-961
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☒ **Public Document – Trade Secret Data Excised**
☐ **Public Document**

Xcel Energy			
Docket No.:	E002/GR-12-961		
Response To:	Department of Commerce	Information Request No.	125
Requestor:	Dale Lusti, Nancy Campbell & Angela Byrne		
Date Received:	December 6, 2012		

Question:

Subject: Sherco 3 Outage
Reference: Direct Testimony of Kent T. Larson
On Pages 29 to 31 identified above, Mr. Larson discusses the Sherco 3 outage.

A. Please identify all insurance proceeds and litigation proceeds that have been received to date and the status of future anticipated proceeds with regard to the Sherco 3 plant damage and related plant outage.

B. Please address for all proceeds provided in (A) above, whether or not proceeds were included in the rate case and if so where, or if proceeds were not included, why that omission is appropriate.

C. Has Xcel Energy experienced increased replacement power costs as a result of the Sherco 3 outage?

D. If the response to (C) above is yes:

(1) Has Xcel Energy passed the increased replacement power costs on to its ratepayers? If so, please quantify these costs showing all calculations.

(2) Please explain how Xcel Energy has passed the increased replacement power costs on to its ratepayers.

(3) Please identify the amount of insurance and litigation proceeds that ratepayers have received (to date) to offset increased replacement power costs with regard to the Sherco 3 outage.

(4) Please identify the total amount of insurance and litigation proceeds ratepayers should expect to receive prior to the beginning of the test-year

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(January 1, 2013) to offset increased replacement power costs with regard to the Sherco 3 outage.

(5) Please identify the total amount of insurance and litigation proceeds ratepayers should expect to receive during the test-year (beginning January 1, 2013) to offset increased replacement power costs with regard to the Sherco 3 outage.

E. Please identify all insurance and litigation proceeds that have been included as an offset to the test-year revenue requirements, to reflect the increased replacement power costs as a result of the Sherco 3 outage.

Response:

A. There has been no litigation related to the Sherco 3 plant damage, and therefore no litigation proceeds have been received to date. The Company has not yet determined whether or not litigation is appropriate but would not, in any event, expect to pursue litigation claims until after the project has been completed and the final costs have been determined. We have received ***[TRADE SECRET BEGINS... ...TRADE SECRET ENDS]*** in insurance payments so far and expect to receive an additional ***[TRADE SECRET BEGINS... ...TRADE SECRET ENDS]*** by the end of 2012. These insurance payments are net of the ***[TRADE SECRET BEGINS... ...TRADE SECRET ENDS]*** deductible and have covered labor and equipment expenses associated with the repairs at Sherco 3.

B. The insurance reimbursements have not been included in the rate case. The Company submits to our insurance providers the work orders, purchase orders and invoices for labor and equipment expenses associated with the repairs at Sherco 3. The Company's insurers then review this material and indemnify the Company for those expenses covered by the master operational property insurance policy.

C. Yes, according to simulation analysis from our computer model discussed in the Company's Sherco 3 update report to the Minnesota Public Utilities Commission on November 7, 2012 in Docket No. E002/M-11-1173, we estimate there have been some increased replacement energy costs relative to the Locational Marginal Prices (LMPs) from MISO Day 2 energy market as a result of the Sherco 3 outage.

PUBLIC DOCUMENT
TRADE SECRET INFORMATION EXCISED

D(1). Yes, as with all applicable monthly system fuel and purchased energy costs, the actual embedded replacement energy costs are passed on to ratepayers through the fuel clause mechanism. Given the dynamic nature of generation systems and the need to make multiple purchase decisions instantaneously in order to respond to load variations, it is impossible to manually determine what energy source was deployed in place of an out-of-service plant. Attachment A to this response details our best estimate of quantifying increased replacement energy costs for the period of November 19, 2011 to October 31, 2012. The approach we employed is as follows:

Average Replacement Cost – Unit Incremental Cost = Cost Change due to Outage

Since our Fuel Clause mechanism is based on accounting records, our actual Sherco Unit 3 outage replacement costs may be different from the simulated results illustrated on Attachment A. In addition, the Unit Incremental Cost is an estimate of the cost of energy from Sherco 3 using assumed coal prices and other incremental costs, and assumed production levels. In some periods, the MISO LMP price was less than the estimated Sherco 3 production cost due to very low natural gas prices and MISO LMP prices. In those hours, the Sherco 3 outage reduced energy costs to our ratepayers.

Please note that Attachment A is marked "Non-Public," as it contains information we consider to be trade secret data as defined by Minn. Stat. §13.37(1)(b). The information derives an independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use. Based on its economic value, the Company maintains this information as trade secret as well as the insurance payment and deductible amounts noted in Part A of this response.

D(2). Please see D(1) above.

D(3). Though we have received insurance payments, these payments have been used to pay for actual parts and labor costs at the plant. As is common in the electric utility industry, our current insurance policy does not provide coverage for replacement power costs. Therefore, the Company and ratepayers have not, and will not, receive any insurance proceeds to cover replacement power costs. As noted above, any litigation proceeds are unknown at this time.

D(4). Please see D(3) above.

PUBLIC DOCUMENT
TRADE SECRET INFORMATION EXCISED

D(5). Please see D(3) above.

E. Please see D(3) above.

Witness:	Kent T. Larson
Preparer:	Bob Miller / Anne Heuer Kerry Koep / John Chow
Title:	Manager, Hazard Insurance / Manager, Revenue Analysis Managing Attorney / Pricing Consultant
Department:	Hazard Insurance / Revenue Requirements North General Counsel / NSPM Regulatory
Telephone:	612-215-5371 / 612-330-6181/ 612-215-4583 / 612-330-7588
Date:	December 21, 2012

PUBLIC DOCUMENT: TRADE SECRET INFORMATION EXCISED

Northern States Power Company

Docket No. E002/GR-12-961
Information Request DOC-125
Attachment Page 1 of 1

Estimation of Sherco Unit 3 Outage Replacement Energy Costs
November 2011 - October 2012

Period	Total Outage MWH	Average Replacement Cost	Unit Incremental Cost	Change in Energy Costs Due to Outages
	[Trade Secret Begins		*[Trade Secret Begins*	*[Trade Secret Begins*
November 2011*		$1,951,782		
December 2011		$7,701,441		
January 2012		$6,299,086		
February 2012		$6,067,854		
March 2012		$5,705,721		
April 2012		$6,140,351		
May 2012		$9,281,594		
June 2012		$9,160,688		
July 2012		$13,199,676		
August 2012		$8,767,767		
September 2012		$4,860,041		
October 2012		$5,327,359		
	Trade Secret Ends]		*Trade Secret Ends]*	*Trade Secret Ends]*
Period Total	3,420,847	$84,463,360	$61,747,321	$22,716,039

* Period from November 19, 2011 to November 30, 2011.

Docket No. E002/GR-12-961
DOC Ex. ___ NAC-8

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy			
Docket No.:	E002/GR-12-961		
Response To:	Department of Commerce	Information Request No.	193
Requestor:	Nancy Campbell, Dale Lusti & Angela Byrne		
Date Received:	January 8, 2013		

Question:

Subject: Sherco 3 Costs
Reference: Larson Direct Testimony on page 15 and other applicable Testimony

A. Please identify all costs of Sherco 3 including but not limited to, depreciation expense, taxes, insurance, O&M, emission chemicals, return on rate base, etc. for 2009 test year, 2009 actual, 2010 actual, 2011 test year, 2011 actual, 2012 actual, 2013 test year.

B. For 2013 test year, did the Company include all costs of Sherco 3, even though this unit is not expected to be operational in the first quarter of 2013? If yes, please explain why this is appropriate in light of the Company's statement that it will be filing a rate case for 2014?

C. Please provide information to support that Sherco 3 will be back in service at the "end of the first quarter of 2013" as stated on page 30 of Mr. Larson's Direct Testimony. Please include percentage of completion of projects related to Sherco 3.

Response:

A. Please see Attachment A for costs associated with Sherco 3 for 2009 test year, 2009 actual, 2010 actual, 2011 test year, 2011 actual, 2012 actual, 2013 test year.

B. Yes. As indicated in the response to part A, the 2013 test year includes costs for Sherco 3. The Company began initial development of the 2013 budget in early 2012, and the budget was completed by August 2012. For planning purposes, the 2013 budget assumed a January 1, 2013 return to service for Sherco 3. By the time of filing of this case, the Company determined that the Sherco 3 restoration project would take additional time and was expected to return to service at the end of the first quarter of 2013.

MINNESOTA DEPARTMENT OF COMMERCE

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AN EQUAL OPPORTUNITY EMPLOYER

November 5, 2014

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Report *In the Matter of the Integration and Transmission Study for the Future Renewable Energy Standard Required by Minnesota Laws 2013, Chapter 85, Article 12, Section 4,* Directed by the Minnesota Department of Commerce-Division of Energy Resources**
Docket No. E999/CI-13-486

Dear Dr. Haar:

The Minnesota Department of Commerce-Division of Energy Resources (Department) provides the attached Report, as required by Minnesota Laws 2013, Chapter 85, Article 12, Section 4 (the Act).

Other than accepting the report, the Minnesota Public Utilities Commission (Commission) is not required to take action. However, the Commission may find the information to be helpful in various decisions that may come before the Commission. The Department and the Study Team who developed the report would be willing to present the material in the report at a Commission Planning Meeting, if that would be helpful. In addition, the Department notes that there will be a webinar on the report on Thursday, November 6, 2014, beginning at 1:30 as discussed further herein.

The Department's consultant, Matt Schuerger, is available to answer any questions the Commission may have on the report.

Sincerely,

/s/ WILLIAM GRANT
Deputy Commissioner

WG/ja
Attachment

I. BACKGROUND

Article 12, section 4 of Minnesota Laws 2013, Chapter 85 required the Minnesota Public Utilities Commission (Commission) to order all electric utilities and transmission companies to conduct an engineering study regarding the effects on the reliability and cost of increasing Minnesota's renewable energy standard (RES) to at least 40 percent by 2030, as follows:

> INTEGRATION AND TRANSMISSION STUDY FOR FUTURE RENEWABLE ENERGY STANDARD.
>
> (a) The commission shall order all Minnesota electric utilities, as defined in Minnesota Statutes, section 216B.1691, subdivision 1, paragraph (b), and all transmission companies, as defined in Minnesota Statutes, section 216B.02, to conduct an engineering study of the impacts on reliability and costs of, and to study and develop plans for the transmission network enhancements necessary to support, increasing the renewable energy standard established in Minnesota Statutes, section 216B.1691, subdivision 2a, to 40 percent by 2030, and to higher proportions thereafter, while maintaining system reliability.
>
> (b) The Minnesota electric utilities and transmission companies must complete the study work under the direction of the commissioner of commerce. Prior to the start of the study, the commissioner, in consultation with Minnesota electric utilities and transmission companies, shall appoint a technical review committee consisting of up to 15 individuals with experience and expertise in electric transmission system engineering, electric power systems operations, and renewable energy generation technology to review the study's proposed methods and assumptions, ongoing work, and preliminary results.
>
> (c) As part of the planning process, the Minnesota electric utilities and transmission companies must incorporate and build upon the analyses that have previously been done or that are in progress including but not limited to the 2006 Minnesota Wind Integration Study and ongoing work to address geographically dispersed development plans, the 2007 Minnesota Transmission for Renewable Energy Standard Study, the 2008 and 2009 Statewide Studies of Dispersed Renewable Generation, the 2009 Minnesota RES Update, Corridor, and Capacity Validation Studies, the 2010 Regional Generation Outlet Study, the 2011 Multi Value Project Portfolio Study, and recent and ongoing Midcontinent Independent System Operator transmission expansion planning work. The utilities and transmission companies shall collaborate with the Midcontinent Independent System Operator to optimize and integrate, to the extent possible, Minnesota's transmission plans with other

> regional considerations and to encourage the Midcontinent Independent System Operator to incorporate Minnesota's planning work into its transmission expansion future planning.
>
> (d) The study must be completed and submitted to the Minnesota Public Utilities Commission by November 1, 2014. The report shall include a description of the analyses that have been conducted and the results, including:
>
> (1) a conceptual plan for transmission necessary for generation interconnection and delivery and for access to regional geographic diversity and regional supply and demand side flexibility; and
>
> (2) identification and development of potential solutions to any critical issues encountered to support increasing the renewable energy standard to 40 percent by 2030, and to higher proportions thereafter, while maintaining system reliability.

This report, called the "Minnesota Renewable Energy Integration and Transmission Study" (MRITS), is intended to fulfill this requirement. The Minnesota Department of Commerce (Department) requests that the Commission accept the report.

II. SUMMARY OF REPORT

The Minnesota utilities and transmission companies, in coordination with the Midcontinent Independent System Operator (MISO), conducted the engineering study. The Department directed the study, conducted by a preeminent technical study team of highly skilled local, regional, and national engineering organizations. The utilities' most experienced planning and operations engineers worked hard and constructively throughout the year to accomplish, in collaboration with MISO, a successful and timely completion of the study.[1] In addition to key personnel from Minnesota's utilities, the team included Excel Engineering Inc. (power flow analysis, conceptual transmission plan), MISO (production simulation analysis), and GE Energy Consulting (operational performance analysis, dynamics analysis, mitigations and solutions, study report).

The Department greatly appreciates all of the work by the technical review team and particularly appreciates Great River Energy's (GRE) early and ongoing leadership with the study.

The following are the key findings of the MRITS report:

- The addition of wind and solar (variable renewable) generation to supply 40 percent of Minnesota's annual electric retail sales can be reliably accommodated by the electric power system.

[1] The Department acknowledges that the report is being filed subsequent to the November 1, 2014 due date. The extra days were needed to allow for final review and incorporation of edits.

- With upgrades to existing transmission, the power system can be successfully operated for all hours of the year (no unserved load, no reserve violations, and minimal curtailment of renewable energy) with wind and solar resources increased to achieve 40 percent renewable energy in Minnesota and with current renewable energy standards fully implemented in neighboring MISO North/Central states.
- Further analysis would be needed to ensure system reliability at 50 percent of Minnesota's annual electric retail sales from variable renewables.
- With wind and solar resources increased to achieve 50 percent renewable energy in Minnesota and 25 percent renewable energy in MISO North / Central (10 percent above current renewable energy standards in neighboring states), MRITS production simulation results show that, with significant transmission upgrades and expansions in the five state area, the power system can be successfully operated for all hours of the year (no unserved load, no reserve violations, and minimal curtailment of renewable energy).
- Due to study schedule limitations, no dynamic analysis was performed for 50 percent renewable energy in Minnesota; such analysis would be necessary to ensure system reliability.

III. RECOMMENDED NEXT STEPS

This MRITS report does not requires action by the Commission. However, the report may provide helpful information in proceedings that may come before the Commission. The Department and the Study Team who developed the report would be willing to present the material in the report at a Commission Planning Meeting, if that would be helpful.

In addition, there will be a webinar on the report on Thursday, November 6, 2014, beginning at 1:30. Registration is at: https://www1.gotomeeting.com/register/314429457

/ja

GE Energy Consulting

Minnesota Renewable Energy Integration and Transmission Study

Final Report

Prepared for:

- The Minnesota Utilities and Transmission Companies
- The Minnesota Department of Commerce

Prepared by:

- GE Energy Consulting, *with contributions by:*
  - The Minnesota Utilities and Transmission Companies
  - Excel Engineering, Inc.
  - MISO

In Collaboration with MISO

October 31, 2014

Legal Notices

This report was prepared by General Electric International, Inc. (GE) as an account of work sponsored by Great River Energy which was serving as a representative of the Minnesota Utilities and Transmission Companies. Neither Great River Energy nor GE, nor any person acting on behalf of either:

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October 31, 2014

In 2013 the Minnesota Legislature adopted a requirement for a Renewable Energy Integration and Transmission Study[1] (MRITS). MRITS is an engineering study of increasing the Minnesota Renewable Energy Standard to 40% by 2030, and to higher proportions thereafter, while maintaining system reliability.

Background. MRITS builds upon prior renewable integration studies and related technical work and is coordinated with recent and current regional power system study work. Over summer 2013, Commerce reviewed prior and current related studies and worked with stakeholders and study participants to identify key issues. In fall 2013, Commerce held a stakeholder meeting to discuss the objectives, scope, schedule, and process. The study began in November 2013 and was completed in October 2014.

Study details. *MRITS is focused on the reliability impacts of increased levels of variable renewables (wind and solar generation) and the associated costs of those impacts.* The study scope was developed from statutory guidance, stakeholder input, and technical study team refinement. MRITS incorporates three core and interrelated analyses: 1) *Power flow analysis* for development of a conceptual transmission plan, which includes transmission necessary for generation interconnection and delivery and for access to regional geographic diversity and system flexibility; 2) *Production simulation analysis* which evaluates hour-by-hour operational performance for an entire year, including reserve violations, unserved load, wind / solar curtailments, thermal cycling, and ramp rate and ramp range, and, to screen for challenging time periods; and 3) *Dynamics analysis*, which includes transient stability analysis and weak system strength analysis. The broad study scope and the aggressive schedule have been very significant challenges.

Technical team. *The MN utilities and transmission companies, in coordination with MISO, conducted the engineering study.* The Department of Commerce directed the study. The Minnesota utilities and transmission companies engaged early in the study development and, through the active participation of the companies' most experienced planning and operations engineers, worked hard and constructively throughout the year to accomplish, in collaboration with MISO, a successful and timely completion of the study. A preeminent technical study team of highly skilled local, regional, and national engineering organizations was assembled to work collaboratively on the analysis. This included major contributions from the Minnesota utilities and transmission companies (siting, conceptual transmission plan), Excel Engineering Inc (power flow analysis, conceptual transmission plan), MISO (production simulation analysis), and GE

[1] MN Laws 2013, Chapter 85 HF 729, Article 12, Section 4; MPUC Docket No. CI-13-486.

Energy Consulting (operational performance analysis, dynamics analysis, mitigations and solutions, study report). Great River Energy (GRE) provided key early and ongoing study leadership. GRE's Gordon Pietsch organized and coordinated full participation by the Minnesota utilities and transmission companies and GRE's Jared Alholinna led the technical study team – both worked tirelessly and effectively to ensure the best, most knowledgeable, most experienced engineers were organized, funded, focused, and coordinated throughout the study.

Study review. The study has greatly benefited from extensive ongoing review and guidance by an expert Technical Review Committee (TRC). The Department of Commerce appointed and led the TRC, which included engineers with experience and expertise in electric transmission system engineering, electric power system operations, and renewable energy generation technology. Seven TRC meetings, four full day and three half day, were held throughout the course of the study to review and discuss the study methods and assumptions, scenarios, model development, results, and key findings. *With excellent input from the utilities and transmission companies, MISO, renewables specialists, and national experts, consensus was reached on overall study methods and assumptions, on the scenarios to be studied, on the modeling approach, and on the results and key findings.*

Key findings. *The analytical results from this study show that the addition of wind and solar (variable renewable) generation to supply 40% of Minnesota's annual electric retail sales can be reliably accommodated by the electric power system.* The MRITS operational and dynamics analyses results show that, with upgrades to existing transmission, the power system can be successfully operated for all hours of the year (no unserved load, no reserve violations, and minimal curtailment of renewable energy) with wind and solar resources increased to achieve 40% renewable energy in Minnesota and with current renewable energy standards fully implemented in neighboring MISO North/Central states. *Further analysis would be needed to ensure system reliability at 50% of Minnesota's annual electric retail sales from variable renewables.* With wind and solar resources increased to achieve 50% renewable energy in Minnesota and 25% renewable energy in MISO North / Central (10% above current renewable energy standards in neighboring states), MRITS production simulation results show that, with significant transmission upgrades and expansions in the five state area, the power system can be successfully operated for all hours of the year (no unserved load, no reserve violations, and minimal curtailment of renewable energy). Due to study schedule limitations, no dynamic analysis was performed for 50% renewable energy in Minnesota (Scenarios 2 and 2a) and this analysis is necessary to ensure system reliability.

Thank you to all of the study participants for an extraordinary and collaborative effort and for successful completion of a ground breaking study.

Sincerely,

William Grant
Deputy Commissioner, Division of Energy Resources

Technical Study Team

Jared Alholinna, P.E. (Great River Energy) – Technical Study Team Lead

GE Energy Consulting (GE) – operating performance, dynamics, mitigations / solutions

Douglas Welsh	Durga Gautam	Robert D'Aquila
Richard Piwko	Eknath Vittal	Slobodan Pajic
Gary Jordan	Nicholas Miller	

Excel Engineering, Inc. – power flow analysis, transmission conceptual plan

Michael Cronier, P.E.	LaShel Marvig, P.E.

MISO – technical coordination, models, data; production simulation analysis

Jordan Bakke	Brandon Heath	Cody Doll
Aditya Jayam Prabhakar		

Technical Study Team participants – weekly coordination calls, ongoing technical study participation with Excel Engineering, General Electric and MISO.

Kevin Demeny	American Transmission Company
Steve Porter, P.E.	Dairyland Power Cooperative
Richa Singhal	Great River Energy
Jeff Eddy	ITC Midwest
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Michael Riewer	Otter Tail Power
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Andrew Lucero, P.E	Representing CMMPA
Steve Beuning	Xcel Energy
Jarred Cooley	Xcel Energy
Amanda King	Xcel Energy
Dean Schiro, P.E.	Xcel Energy

Technical Review Committee (TRC)

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Steve Beuning, Director Market Operations	Xcel Energy
Jeff Eddy, Manager Planning	ITC Holdings
Brendan Kirby, Consultant, Grid Integration & Reliability	NREL
Mark Mitchell, Director of Operations and COO	SMMPA
Michael Milligan, Principal Researcher, Grid Integration	NREL
Dale Osborn, Consulting Advisor, Policy & Economic Studies	MISO
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Dean Schiro, P.E., Manager Real Time Planning	Xcel Energy
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<u>Observers</u>	
Cezar Panait, P.E., Regulatory Engineer	MN Public Utilities Commission
Lise Trudeau, Engineer	MN Department of Commerce

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Nomenclature

BAU	Business as Usual
CC or CCGT	Combined Cycle Gas Turbine
CEMS	Continuous Emissions Monitoring Systems
CF	Capacity Factor
CO2	Carbon Dioxide
CSCR	Composite Short-Circuit Ratio
CV	Capacity Value
DA	Day-Ahead
DIR	Dispatchable Intermittent Resource
DPV	Distributed Photovoltaic Generation Resource
DR	Demand Response
DSM	Demand Side Management
EI	Eastern Interconnection
EMTP	Electro-Magnetic Transients Program
ERGIS	Eastern Renewable Generation Integration Study (by NREL)
EWITS	Eastern Wind Integration and Transmission Study (by NREL)
FERC	Federal Energy Regulatory Commission
GE	General Electric International, Inc. / GE Energy Consulting
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatt Hour
HA	Hour Ahead
HVDC	High-Voltage Direct-Current
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
LBA	Local Balancing Authority
LMP	Locational Marginal Prices
MRITS	Minnesota Renewable Energy Integration and Transmission Study
MTEP	MISO Transmission Expansion Plan
MVA	Megavolt Ampere
MVP	Multi-Value Project
MW	Megawatts
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation

Nomenclature

NOx	Nitrogen Oxides
NREL	National Renewable Energy Laboratory
NS	Non-Synchronous
O&M	Operation & Maintenance
PJM	PJM Interconnection, LLC.
POI	Point of Interconnection
PPA	Power Purchase Agreement
PSCAD	Manitoba HVDC Research Centre's Electro-Magnetic Transients Simulation program (Power System Computer Aided Design)
PSH	Pumped Storage Hydro
PV	Photovoltaic
RE	Renewable Energy
REC	Renewable Energy Credit
RES	Renewable Energy Standard
RGOS	Regional Generation Outlet Study
RPS	Renewable Portfolio Standard
SCED	Security Constrained Economic Dispatch
SCR	Short-Circuit Ratio
SCUC	Security Constrained Unit Commitment
SES	Solar Energy Standard
SOx	Sulfur Oxides
ST	Steam Turbine
STATCOM	Static Compensator
SVC	Static Var Compensator
TPL	NERC's Transmission Planning Standard
TRC	Technical Review Committee
TWh	Terawatt Hour (1000 Megawatt hours)
VOC	Variable Operating Cost
WTG	Wind Turbine-Generator
ZVRT	Zero-Voltage Ride-Through

1 EXECUTIVE SUMMARY

1.1 Background

In 2013 the Minnesota Legislature adopted a requirement for a Renewable Energy Integration and Transmission Study[1] (MRITS). The MN utilities and transmission companies, in coordination with MISO, conducted the engineering study. The Department of Commerce directed the study and appointed and led the Technical Review Committee (TRC). It is an engineering study of increasing the Minnesota Renewable Energy Standard to 40% by 2030, and to higher proportions thereafter, while maintaining system reliability. The final study includes: 1) A conceptual plan for transmission for generation interconnection and delivery and for access to regional geographic diversity and regional supply and demand side flexibility, and 2) Identification and development of potential solutions to any critical issues encountered.

All utilities with Minnesota retail electric sales and all Minnesota transmission companies participated and/or were represented in the study. Eight Minnesota Local Balancing Authorities are represented and over 85% of the Minnesota retail sales are in the four largest Local Balancing Authorities (LBA): Xcel Energy (NSP), Great River Energy, Minnesota Power, and Otter Tail Power. The study area is within the NERC reliability region Midwest Reliability Organization (MRO). Nearly all of the Minnesota retail sales are within the Midcontinent Independent System Operator (MISO). The Local Balancing Authorities within MISO, including the Minnesota LBAs, are functionally consolidated.

Prior studies of relevance include the 2006 Minnesota Wind Integration Study[2], the 2007 Minnesota Transmission for Renewable Energy Standard Study[3], the 2009 Minnesota RES Update, Corridor, and Capacity Validation Studies, the 2008 and 2009 Statewide Studies of Dispersed Renewable Generation[4], the 2010 Regional Generation Outlet Study, the 2011 Multi Value Project Portfolio Study, the 2013 Minnesota Biennial Transmission Project Report[5], the 2013 MISO Transmission Expansion Plan, and recent and ongoing MISO transmission expansion planning work[6] .

[1] MN Laws 2013, Chapter 85 HF 729, Article 12, Section 4; MPUC Docket No. CI-13-486.
[2] 2006 MN Wind Integration Study. Prepared for the MPUC, Nov 2006.
Final Report Volumes I & II, Final Report Presentation. http://www.puc.state.mn.us/PUC/electricity/013752
[3] "Minnesota RES Update Study Technical Report." March 2009. "RES Transmission Report." November 2007.
"Southwest Twin Cities – Granite Falls Transmission Upgrade Study Technical Report." March 2009.
"Capacity Validation Study Report." March 2009. http://www.minnelectrans.com/reports.html
[4] Dispersed Renewable Generation Studies. June 2008 and September 2009.
http://mn.gov/commerce/energy/topics/resources/Reports-Data/Energy-Reports.jsp
[5] http://www.minnelectrans.com/, November 1, 2013.
[6] https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx

1.2 Study Objectives and Overall Approach

The study objectives are listed below.

1. Evaluate the impacts on reliability and costs associated with increasing Renewable Energy to 40% of Minnesota retail electric energy sales by 2030, and to higher proportions thereafter;
2. Develop a conceptual plan for transmission necessary for access to regional geographic diversity and regional system flexibility;
3. Identify and develop options to manage the impacts of the renewable energy resources;
4. Build upon prior wind integration studies and related technical work; Coordinate with recent and current regional power system study work;
5. Produce meaningful, broadly supported results through a technically rigorous, inclusive study process.

This study is focused on the reliability impacts of increased levels of variable renewables (wind and solar generation) and the associated costs of those impacts.

MRITS builds upon prior wind integration studies and related technical work and is coordinated with recent and current regional power system study work. The study scope was developed from statutory guidance, stakeholder input, and technical study team refinement.

MRITS incorporates three core and interrelated analyses: 1) *Power flow analysis* for development of a conceptual transmission plan, which includes transmission necessary for generation interconnection and delivery and for access to regional geographic diversity and regional supply and demand side flexibility; 2) *Production simulation analysis* for evaluation of operational performance, including reserve violations, unserved load, wind / solar curtailments, thermal cycling, and ramp rate and ramp range, and, to screen for challenging time periods; and 3) *Dynamics analysis*, which includes transient stability analysis and weak system strength analysis.

The MRITS study area is Minnesota-centric, which focuses on the combined operating areas of the Minnesota utilities and transmission companies, in the context of the MISO North/Central areas and the neighboring regions to the west and north.

The base study models (baseline and scenarios) are coordinated with and consistent with MISO models and databases including dispatch to the MISO market. Additional options were considered in Task 7 (Identify & Develop Mitigations / Solutions) as needed.

The key study tasks are:

- Develop Study Scenarios; Site Wind and Solar Generation (Lead contributors: Minnesota Utilities; Minnesota Department of Commerce)
- Perform Production Simulation Analysis (Lead Contributor: MISO)
- Perform Power Flow Analysis; Develop Transmission Conceptual Plan (Lead Contributors: Minnesota Utilities & Transmission Owners; Excel Engineering)
- Evaluate Operational Performance (Lead Contributor: GE Energy Consulting)

- Screen for Challenging Periods (Lead Contributor: GE Energy Consulting)
- Evaluate stability related issues, including transient stability performance, voltage regulation performance, adequacy of dynamic reactive support, and weak system strength issues (Lead Contributor: GE Energy Consulting)
- Identify and Develop Mitigations and Solutions (Lead Contributor: GE Energy Consulting)

1.3 Development of Study Scenarios

The Baseline scenario has sufficient renewable energy generation to satisfy the current renewable energy standards and solar energy standards for all states in the study region. For Minnesota, the Baseline scenario was based on current Minnesota utility plans to meet the Minnesota Renewable Energy Standard (RES) and the Solar Energy Standard (SES) with renewable energy (wind, solar, small hydro, biomass, etc) from the Minnesota-centric area and incorporates refinements from the technical study team. For non-Minnesota MISO states in the study footprint, the Baseline scenario was based on the prior approved 2013 MISO Transmission Expansion Plan (MTEP13).

Scenario 1 builds on the Baseline scenario by adding incremental wind and solar (variable renewables) generation to the Baseline model to supply a total of 40% of Minnesota annual electric retail sales from renewables in the study year and with all states at full implementation of their current RESs.

Scenario 2 builds on Scenario 1 by adding incremental wind and solar generation to the Scenario 1 model to supply 50% of Minnesota electric retail sales from total renewables and by further adding incremental wind and solar generation to supply an additional 10% of the non-Minnesota MISO North / Central retail electric sales from total renewables (i.e. to increase the MISO footprint renewables 10% above full implementation of the current RESs).

Table 1-1 Study Scenarios

Scenario	Minnesota RE Penetration	MISO Wind & Solar Penetration (including Minnesota)
Baseline	28.5%	14.0%
Scenario 1	40.0%	15.0%
Scenario 2	50.0%	25.0%

Note: MISO has an additional 3% renewable energy penetration in all scenarios from existing small biomass and small hydro.

The horizon year for this study was 2028 (to represent 2030 conditions). System load levels for Minnesota and MISO regions were scaled up from present levels by an assumed annual growth rate of 0.5% for Minnesota and 0.75% for the rest of MISO North / Central.

All scenarios, including the Baseline, required more wind and solar generation than what is already installed on the grid. Therefore, the study team used a combination of wind/solar resource maps and wind/solar profile data (from NREL) to guide selection of sites for prospective future wind and solar plants with cumulative capacities consistent with the renewable energy targets for each study scenario. Wind Plant sites were distributed among several of MISO's renewable energy zones

(originally developed in the MISO Regional Generation Outlet Study and used in the Multi-Value Project Portfolio study).

1.4 Development of Transmission Conceptual Plans

A conceptual transmission plan was developed for each of the study scenarios. System reliability was determined through traditional transmission planning methods, criteria, and assumptions. Steady state performance characteristics were evaluated with the system intact as well as under powerflow contingency conditions (N-1 outages and selected multiple contingency outages per NERC TPL Category C2 & C5).

The Baseline scenario started with a transmission model that was consistent with the 2013 MTEP 2023 model. This Baseline transmission model incorporates planned transmission lines, including the CapX2020 Group I lines and the MISO Multi-Value Project (MVP) portfolio. A very limited number of facilities were overloaded in the Baseline Scenario.

For Scenario 1, a total of 54 transmission mitigations were added to accommodate the increased wind and solar generation. These mitigations included transmission line upgrades, transformer additions/replacements, and changes to substation terminal equipment, with a total estimated cost of $373M. No new transmission lines were required.

In Scenario 2, a total of 17,245 MW of new wind/solar generation was added to increase Minnesota renewable energy penetration to 50% and MISO renewable energy penetration to 25%. A total of 9 new transmission lines and 30 transmission upgrades were added to the Scenario 1 transmission system, with a total estimate cost of an additional $2.6B. Note that an undetermined portion of the Scenario 2 transmission expansions and upgrades are associated with increasing MISO's renewable penetration from 15% to 25%.

Note that for the development of transmission conceptual plans, the new wind and solar resources were connected to high voltage transmission buses. The actual connection processes will likely require additional plant-specific interconnection facilities for the new wind and solar plants.

1.5 Evaluation of Operational Performance

Operational performance of the electric power grid with increased levels of renewable generation was analyzed using production simulation analysis, which simulates hourly operation of the system for an entire year. The PLEXOS simulation tool uses a Day-Ahead Security Constrained Unit Commitment (SCUC) and Real-Time Security Constrained Economic Dispatch (SCED) interleaved market dispatch solution. This type of modeling accurately captures the forecast uncertainties realized between a Day-Ahead and Real-Time markets. Modeling of forecast uncertainty becomes increasingly important when dealing with high levels of wind and solar generation because the output tends to be more stochastic in nature.

MISO used the 2013 MTEP Business as Usual (BAU) dataset as a starting point for the Baseline Scenario, with modifications to the system load level to reflect the 2028 horizon year for this study. The BAU future is considered the status quo future and continues current economic trends. The MTEP futures are created by MISO and vetted by the MISO Planning Advisory Committee (PAC) stakeholder committee. Information for the production modeling dataset is sourced from Ventyx

and updated through an extensive MISO process to bring it into line with the most current data and expected future conditions. Coal unit retirements totaling 12.6 GW were included in the model per MISO's anticipated effects of prior EPA regulations.

Future EPA regulations, such as the recently proposed Clean Power Plan (111d) which is still in development, are not modeled nor considered in this study. The model footprint includes all areas in the Eastern Interconnect, with the exception of Florida, ISO New England and Eastern Canada.

For the Scenarios 1 and 2, new wind and solar generation was added at the locations determined in the siting task and transmission system upgrades/expansions were added per the conceptual transmission plans.

One aspect of the BAU set of assumptions is that many coal plants within MISO will continue to operate as they do now. That is, the plants remain on-line when economic market signals would have initiated a brief period of decommitment and effectively act as "must-run" units. In order to examine the sensitivity to changing this assumption, and to the assumption of coal unit retirements, Scenarios 1a and 2a were added to the production simulation analysis as sensitivity cases relative to Scenarios 1 and 2. Scenarios 1a and 2a included the following changes in assumptions:

- All coal units were economically committed
- Nine additional coal units in the Minnesota-centric region were assumed to be available (These units were assumed unavailable in Scenarios 1 and 2)
- Forced outage modeling of conventional generation was included

The production simulation results were analyzed to assess system operational performance with respect to the following parameters; annual energy production by type of generating resource, renewable energy resource utilization and curtailment, cycling duty of thermal plants, adequacy of ramping capability of the MISO generation fleet, and risk of reserve violations and unserved load. For Scenario 1, the results were also screened to select challenging operating conditions for dynamic performance, and these operating points were subsequently analyzed with fault simulations in the dynamics task.

1.6 Dynamic Performance Analysis

A dynamic simulation model was developed to perform transient stability analysis of the study scenarios. A series of dynamic data files were provided by the Minnesota utilities, based on the MTEP 2013 dataset. As with the power flow and production system models, new wind and solar generation was added at the locations determined in the siting task and transmission system upgrades/expansions were added per the conceptual transmission plans. In order to capture possible fault-induced delayed recovery issues caused by reduced levels of synchronous generation, the load models in the Minnesota-Centric region were refined to include a more detailed representation of load composition, including dynamic characteristics.

New utility-scale wind and solar photovoltaic (PV) plant models were consistent with current NERC and FERC minimum requirements (e.g. voltage regulation, power factor, voltage ride-through). Full commercial technical capability (e.g. synthetic inertia, frequency response) was not modeled. Distributed PV was modeled as lumped generation at locations (per the siting task) with no reactive power or voltage regulation capability.

New wind plants were split roughly 50/50 between Type 3 (double fed asynchronous generator (DFAG) and Type 4 (full converter).

A representative number of regional power system fault conditions were simulated to stress the system in different ways.

- Faults known to be severe challenges to system transient stability from numerous past stability studies,
- Faults in regions with high concentrations of wind and solar plants, where voltage recovery is highly dependent on the reactive power support from wind and solar plants.
- Faults affecting major transmission interfaces during periods of high power transfer

The results of all dynamic simulation cases were screened with respect to a set of performance criteria, including angular stability, oscillatory stability, voltage dips, and voltage recovery.

Weak system issues were also investigated using the dynamic system models. When the ac system impedance is high relative to the aggregate rating of wind and solar generation in a given region, the internal controllers and regulators within wind and solar inverters become less stable. If the system is excessively weak, control instabilities may occur. Composite short-circuit ratio analysis was conducted to determine system strength in the study scenarios with respect to emerging industry understanding of this issue.

1.7 Key Findings

This study examined two levels of increased wind and solar generation for Minnesota; 40% (represented by Scenarios 1 and 1a) and 50% (represented by Scenarios 2 and 2a). In the 40% Minnesota Scenario, MISO North/Central is at 15% (current state RESs). The 50% Minnesota Scenario also included an increase of 10% (to 25%) in the MISO North/Central region. Production simulation was used to examine annual hourly operation of the MISO North/Central system for all four of these scenarios. Transient and dynamic stability analysis was conducted for Scenarios 1 and 1a but not on Scenarios 2 and 2a.

1.7.1 General Conclusions for 40% RE Penetration in Minnesota

With wind and solar resources increased to achieve 40% renewable energy for Minnesota and 15% renewable energy for MISO North/Central, production simulation and transient/dynamic stability analysis results indicate that the system can be successfully operated for all hours of the year with no unserved load, no reserve violations, and minimal curtailment of renewable energy. This assumes sufficient transmission mitigations, as described in Section 1.4, to accommodate the additional wind and solar resources.

This is operationally achievable with most coal plants operated as baseload must-run units, similar to existing operating practice. It is also achievable if all coal plants are economically committed per MISO market signals, but additional analysis would be required to better understand implications, tradeoffs, and mitigations related to increased cycling duty.

Dynamic simulation results indicate that there are no fundamental system-wide dynamic stability or voltage regulation issues introduced by the renewable generation assumed in Scenario 1 and 1a. This assumes:

- New wind turbine generators are a mixture of Type 3 and Type 4 turbines with standard controls
- The new wind and utility-scale solar generation is compliant with present minimum performance requirements (i.e. they provide voltage regulation/reactive support and have zero-voltage ride through capability)
- Local-area issues are addressed through normal generator interconnection requirements

1.7.2 General Conclusions for 50% RE Penetration in Minnesota

With wind and solar resources increased to achieve 50% renewable energy in Minnesota and 25% renewable energy in MISO, production simulation results indicate that the system can be successfully operated for all hours of the year with no unserved load, no reserve violations, and minimal curtailment of renewable energy. This assumes sufficient transmission upgrades, expansions and mitigations to accommodate the additional wind and solar resources.

This is operationally achievable with most coal plants operated as baseload must-run units, similar to existing operating practice. It is also achievable if all coal plants are economically committed per MISO market signals, but additional analysis would be required to better understand implications, tradeoffs, and mitigations related to increased cycling duty.

No dynamic analysis was performed for the study scenarios with 50% renewable energy for Minnesota (Scenarios 2 and 2a) due to study schedule limitations and this analysis is necessary to ensure system reliability.

1.7.3 Annual Energy in the Minnesota-Centric Region

Figure 1-1 shows the annual load and generation energy by type for the Minnesota-Centric region. Comparing Scenarios 1 and 1a (40% MN renewables) with the Baseline,

- Wind and solar energy increases by 8.5 TWh, all of which contributes to bringing the State of Minnesota from 28.5% RE penetration to 40% RE penetration
- There is very little change in energy from conventional generation resources
- Most of the increase in wind and solar energy is balanced by a decrease in imports. The Minnesota-Centric region goes from a net importer to a net exporter.

Comparing Scenarios 2 and 2a (50% MN renewables) with Scenarios 1 and 1a (40% MN renewables),

- Wind and solar energy increases by 20 TWh. Of this total, 4.8 TWh brings the State of Minnesota from 40% to 50% RE penetration and the remainder contributes to bringing MISO from 15% to 25% RE penetration
- Most of the increase in wind and solar energy in the Minnesota-Centric region is balanced by a decrease in coal generation and an increase in net exports to neighboring regions
- Gas-fired, combined-cycle generation declines from 5.0 TWh in Scenario 1 to 3.0 TWh in Scenario 2.

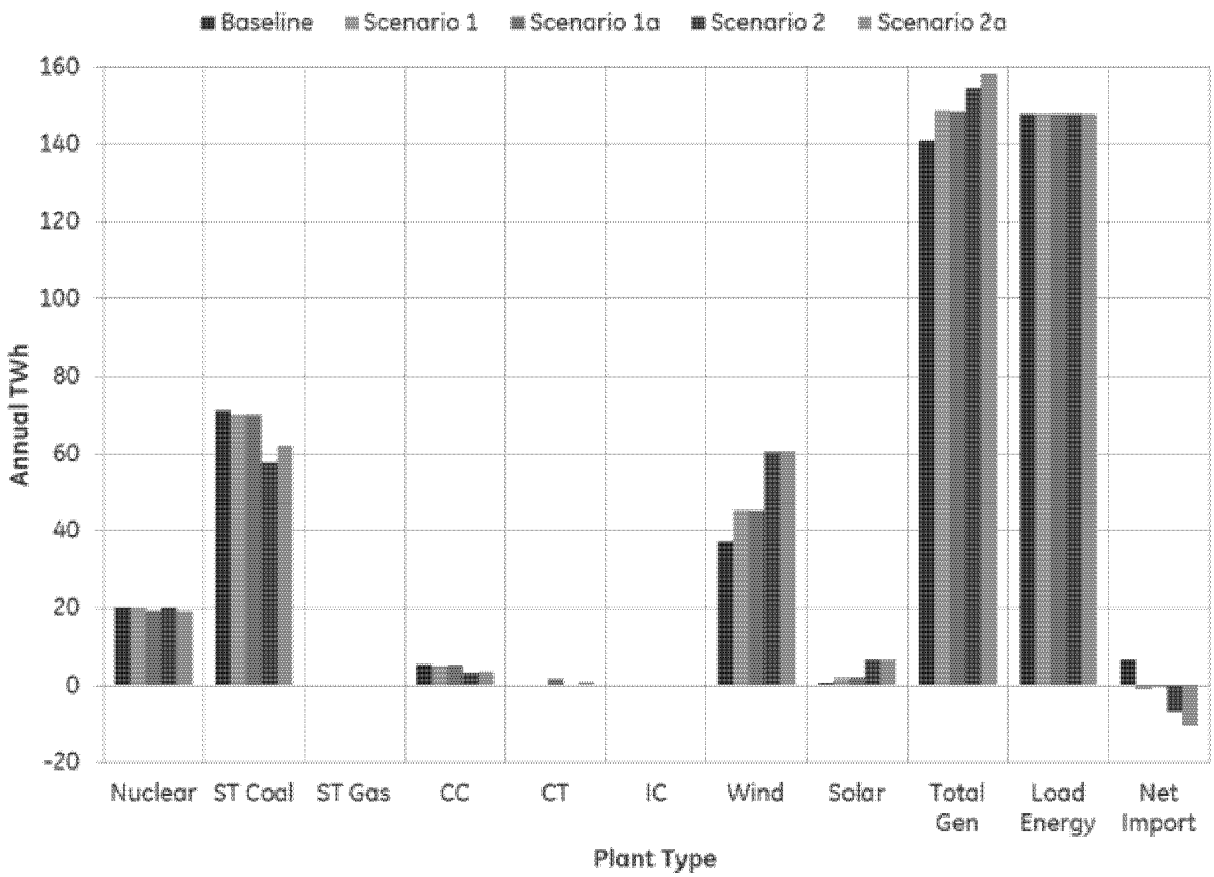

Figure 1-1 Annual Energy by Type in Minnesota-Centric Region for Study Scenarios

1.7.4 Cycling of Thermal Plants

Most coal plants were originally designed for baseload operation; that is, they were intended to operate continuously with only a few start/stop cycles in a year (mostly due to scheduled or forced outages). Increased cycling duty could increase wear and tear on these units, with corresponding increases in maintenance requirements. Many coal plants in MISO presently are designated by the plant's owner to operate as "must-run" in order to avoid start/stop cycles that would occur if they were economically committed by the market.

Scenarios S1a and S2a assumed that all coal plants in MISO are subject to economic commitment/dispatch (i.e., not must-run) based on day-ahead forecasts of load, wind and solar energy within MISO. Production simulation results show significant coal plant cycling due to economic market signals:

- Small coal units (below 300 MW rating) could have an additional 100 to 200 starts per year, beyond those due to forced or planned outages.
- Large coal units (above 300 MW) could have an additional 20 to 100 starts per year

Scenarios S1 and S2 assumed almost all coal plants would continue to operate as they do today. Coal units were on-line all year (except for scheduled maintenance periods) and were not decommitted during periods of low market prices. The results of these scenarios confirmed that the coal units could remain must-run with minor impacts on overall operation of the Minnesota-Centric region. Coal plant owners could choose to continue the must-run practice to avoid the detrimental impacts of increased cycling as wind and solar penetration increases. Doing so would likely incur some additional operational costs when energy prices fall below a plant's breakeven point. Wind curtailment would also be about 0.5% higher than if the coal plants were economically committed.

An attractive solution to the coal plant cycling issue may exist between the two bookend cases analyzed in this study. Scenarios 1a and 2a assumed that unit commitment was determined on a day-ahead basis, using day-ahead forecasts of wind and solar energy. The result was a high number of start/stop cycles of coal plants, sometimes with down-times of less than 2 days. If the unit commitment process was modified to use a longer term forward market (say 3 to 5 days ahead), then coal plant owners could adjust their operational strategy to consider decommitting units when prolonged periods of high wind/solar generation and low system loads are forecasted. A forward market would depend on longer term forecasts of wind, solar and load energy, consistent with the look-ahead period of the market. Although such forecasts would be somewhat less accurate than day-ahead forecasts, the quality of the forecasts would likely be adequate to support such unit commitment decisions.

This study did not examine the economic or wear-and-tear impacts of increased cycling on coal units. Further information on this topic can be found in the NREL Western Wind and Solar Integration Study Phase 2 report[7] and the PJM Renewable Integration Study report[8].

Combined-cycle (CC) units are better able to accommodate cycling duties than coal plants. Simulation results show that combined cycle units in the Minnesota-Centric region experience from 50 to 200 start/stop cycles per year. Cycling of CC units declines slightly as wind and solar penetration increases. This decline is primarily due to a decrease in CC plant utilization as wind and solar energy increases.

1.7.5 Curtailment of Wind and Solar Energy

In general, a small amount of curtailment is to be expected in any system with a significant level of wind and solar generation. There are some operating conditions where it is economically efficient to accept a small amount of curtailment (i.e., mitigation of that curtailment would be disproportionately expensive and not justifiable).

Overall curtailment in the Minnesota-Centric region is relatively small in all study scenarios, as shown in Table 1-2. Wind curtailment in Baseline and Scenario 1 is primarily due to local transmission congestion at a few wind plants. This congestion could be mitigated by transmission modifications, if economically justifiable.

Wind curtailment in Scenario 2 is due to system-wide operational limits during nighttime hours, when many baseload generators are dispatched to their minimum output levels. This type of curtailment could be reduced by decommitting some baseload generation via economic market

[7] http://www.nrel.gov/electricity/transmission/western_wind.html
[8] http://www.pjm.com/committees-and-groups/task-forces/irtf/pris.aspx

signals. The effectiveness of this mitigation option is illustrated by comparing Scenario 2 (coal units must-run) with Scenario 2a (economic coal commitment). Wind curtailment decreases from 2.14% to 1.60% (reduction of 332 GWh of wind curtailment). Solar curtailment decreases from 0.42% to 0.24% (reduction of 12 GWh of solar curtailment).

Table 1-2 Wind and Solar Curtailment for Study Scenarios

Scenario	Baseline	Scenario 1	Scenario 1a	Scenario 2	Scenario 2a
Wind Curtailment	0.42%	1.00%	1.59%	2.14%	1.60%
Solar Curtailment	0.09%	0.00%	0.23%	0.42%	0.24%

Note: Curtailment is calculated as a percentage of available annual wind or solar energy.

1.7.6 Other Operational Issues

No significant transmission system congestion was observed in any of the study scenarios with the assumed transmission upgrades and expansions. Transmission contingency conditions were considered in both the powerflow analysis used to develop the conceptual transmission system and the security-constrained economic dispatch in the production simulation analysis.

Ramp-range-up and ramp-rate-up capability of the MISO conventional generation fleet increases with increased penetration of wind and solar generation. Conventional generation is generally dispatched down rather than decommitted when wind and solar energy is available, which gives those generators more headroom for ramping up if needed.

Ramp-range-down and ramp-rate-down capability of the MISO conventional generation fleet decreases with increased penetration of wind and solar generation. In Scenario 2, there are 500 hours when ramp-rate-down capability of the conventional generation fleet falls below 100 MW/min. Periods of low ramp-down capability coincide with periods of high wind and solar generation. Wind and solar generators are capable of providing ramp-down capability during these periods. MISO's existing Dispatchable Intermittent Resource (DIR) process already enables this for wind generators. It is anticipated that MISO would expand the DIR program to include solar plants in the future.

1.7.7 System Stability, Voltage Support, Dynamic Reactive Reserves

No angular stability, oscillatory stability or wide-spread voltage recovery issues were observed over the range of tested study conditions. The 16 dynamic disturbances used in stability simulations included key traditional faults/outages as well as faults/outages in areas with high concentrations of renewables and high inter-area transmission flows. System operating conditions included light load, shoulder load and peak load cases, each with the highest percent renewable generation periods in the Minnesota-Centric region.

Overall dynamic reactive reserves are sufficient and all disturbances examined for Scenarios 1 and 1a show acceptable voltage recovery. The South & Central and Northern Minnesota regions get the majority of their dynamic reactive support from synchronous generation. Maintaining sufficient dynamic reserves in these regions is critical, both for local and system-wide stability.

Southwest Minnesota, South Dakota and at times Iowa get a significant portion of dynamic reactive support from wind and solar resources. Wind and Solar resources contribute significantly to voltage support/dynamic reactive reserves. The fast response of wind/solar inverters helps voltage recovery following transmission system faults. However, these are current-source devices with little or no overload capability. Their reactive output decreases when they reach a limit (low voltage and high current).

Synchronous machines (either generators or synchronous condensers), on the other hand, are voltage-source devices with high overload capability. This characteristic will strengthen the system voltage, allowing better utilization of the dynamic capability of renewable generation. The mitigation methods discussed below, namely stiffening the ac system through new transmission or synchronous machines, will also address this concern.

Local load areas, such as the Silver Bay and Taconite Harbor area, require reactive support from synchronous machines due to the high level of heavy industrial loads. If all existing synchronous generation in this region is off line (i.e. due to retirement or decommitment), reinforcements such as new transmission or synchronous condensers would be required to support the load.

Dynamic simulation results indicate that it is critical to maintain sufficient system strength and dynamic reserves to support high flows on the Northern Minnesota 500 kV lines and Manitoba high-voltage direct-current (HVDC) lines. Insufficient system strength and reactive support will limit Manitoba exports to the U.S. Existing transmission expansion plans, as modeled in this analysis, address these issues and are sufficient for the anticipated levels of Manitoba exports.

The Manitoba HVDC ties and the 500 kV transmission system in Northern Minnesota require reactive support from synchronous generators, the Dorsey and Riel synchronous condensers, and the Forbes static var compensator (SVC) to maintain the expected level of Manitoba exports. Without sufficient reactive reserves, the system could be unstable for nearby transmission disturbances. The current transmission plans, as modeled in this analysis, address this issue.

1.7.8 Weak System Issues

Composite Short-Circuit Ratio (CSCR) is an indicator of the ability of an ac transmission system to support stable operation of inverter-based generation. A system with a higher CSCR is considered strong and a system with a lower CSCR is considered to be weak. CSCR is calculated as the ratio of the composite short-circuit MVA at the points of interconnection (POI) of all wind/solar plants in a given area to the combined MW rating of all those wind and solar generation resources.

Low CSCR operating conditions can lead to control instabilities in inverter-based equipment (Wind, Solar PV, HVDC and SVC). Instabilities of this nature will generally manifest as growing voltage/current oscillations at the most affected wind or solar plants. In the worst conditions (i.e., very low CSCR), oscillations could become more wide-spread and eventually lead to loss of generation and/or damage to renewable generation equipment if not adequately protected against such events.

This is a relatively new area off concern within the industry. The issue has emerged as the penetration of wind generation has grown. Understanding of the fundamental stability issues is rapidly growing as more wind plants are being installed in regions with weak ac systems.

Equipment vendors, transmission planners and consultants are all working to gain a better understanding of the issues. Modeling and simulation tools have already been developed to enable detailed analysis of the phenomena. Wind and solar inverter control systems are being modified to improve weak system performance.

Synchronous machines (either generators or synchronous condensers) contribute short-circuit strength to the transmission system and therefore increase CSCR. Therefore, system operating conditions with more synchronous generators online will have higher CSCR. Also, stronger transmission ties (additional transmission lines or transformers, or lower impedance transformers) between synchronous generation and regions of wind and solar generation will increase CSCR. SVCs and STATCOMs do not contribute short-circuit current, and because they are electronic converter based devices with internal control systems similar to wind/solar inverters, their presence in a weak system region could further reduce the effective CSCR and exacerbate the control system stability issues that occur in weak system conditions.

There are two general situations where weak system issues generally need to be assessed:

- Local pockets of a few wind and solar plants in regions with limited transmission and no nearby synchronous generation (e.g. plants in North Dakota fed from Pillsbury 230 kV near Fargo).
- Larger areas such as Southwest Minnesota (Buffalo Ridge area) with a very high concentration of wind and solar plants and no nearby synchronous generation

This study examined the sensitivity of weak system issues in Southwest Minnesota. Observations are as follows:

The trouble spots identified in this analysis are not very sensitive to existing synchronous generation commitment. While there is very little synchronous generation within the area, the region is supported by a strong networked 345 kV transmission grid. Primary short circuit strength is from a wide range of base-load units in neighboring areas, and interconnected via the 345 kV transmission network. Commitment, decommittment or outages of individual synchronous generators do not have significant impact on CSCR in these identified areas.

Transmission outages will lower system strength and make the issue worse. When performing CSCR and weak system assessments as wind and solar penetration increases, it will be prudent to consider normal and design-criteria outages at a minimum (i.e, outage conditions consistent with MISO reliability assessment practices).

1.7.9 Mitigations

There are two approaches to improving wind/solar inverter control stability in weak system conditions:

- To improve the inverter controls, either by carefully tuning the equipment control functions or modifying the control functions to be more compatible with weak system conditions. With this approach, wind/solar plants can tolerate lower CSCR conditions.
- To strengthen the ac system, resulting in increased short-circuit MVA at the locations of the wind/solar plants. This approach increases CSCR.

The approaches are complementary, so the ultimate solution for a particular region would likely be a combination of both.

Mitigation through Wind/PV Inverter Controls

Standard inverter controls and setting procedures may not be sufficient for weak system applications. Loop gains of internal control functions inherently increase when system impedance increases, thereby reducing the stability margin of the controllers. Developers and equipment vendors must be made aware when new plants are being proposed for weak system regions so they can design/tune controls to address the issue. Wind plant vendors have made significant progress in designing wind and solar plant control systems that are compatible with weak system applications.

This approach becomes somewhat more difficult when there are wind/solar plants from multiple vendors in one region. The level of analysis requires detailed modeling of all affected wind plants at a level of detail that requires the use of proprietary control design information from the vendors. Vendors are very reluctant to share such data, except with independent consultants who can guarantee strict data security. However, this approach is gaining traction and a few projects have made effective implementations. The key to success is that project developers and equipment vendors must be informed beforehand that a given wind or solar plant will be installed at a weak system location. This enables the appropriate control design studies to be initiated before the project is installed.

In the event that such control-based approaches are not sufficient, it would be possible to further improve weak system performance by employing one or more of the system-level mitigations discussed below.

Mitigation by Strengthening the AC System

CSCR analysis of the Southwest Minnesota region shows that synchronous condensers located near the wind and solar plants would be a very effective mitigation for weak system issues. Synchronous condensers are synchronous machines that have the same voltage control and dynamic reactive power capabilities as synchronous generators. Synchronous condensers are not connected to prime movers (e.g. steam turbines or combustion turbines), so they do not generate power.

Other approaches that reduce ac system impedance could also offer some benefit:

- Additional transmission lines between the wind/solar plants and synchronous generation plants
- Lower impedance transformers, including wind/solar plant interconnection transformers

Series capacitors on transmission lines could be used to increase CSCR and to improve the transmission system's capability to transfer energy out of regions with high concentrations of wind and solar resources. However, series capacitors create subsynchronous frequency resonances in the transmission system which affect the performance of control systems within wind and solar plants. These resonances introduce an additional challenge to wind/solar plant control designs, which must maintain stable operation in the presence of the resonant conditions.Mitigation through

"must-run" operating rules for existing generation was found to be not very effective. The plants with synchronous generators are not located close enough to effected wind/solar plants.

2 PROJECT OVERVIEW

2.1 Background

In 2013 the Minnesota Legislature adopted a requirement for a Renewable Energy Integration and Transmission Study[1] (MRITS). The MN utilities and transmission companies, in coordination with MISO, conducted the engineering study. The Department of Commerce directed the study and appointed and led the Technical Review Committee (TRC). It is an engineering study of increasing the Minnesota Renewable Energy Standard to 40% by 2030, and to higher proportions thereafter, while maintaining system reliability.

The final study includes:

1. A conceptual plan for transmission for generation interconnection and delivery and for access to regional geographic diversity and regional supply and system flexibility, and
2. Identification and development of potential solutions to any critical issues encountered.

All utilities with Minnesota retail electric sales and all Minnesota transmission companies participated and/or were represented in the study. Eight Minnesota Local Balancing Authorities are represented and over 85% of the Minnesota retail sales are in the four largest Local Balancing Authorities: Xcel Energy (NSP), Great River Energy, Minnesota Power, and Otter Tail Power. The study area is within the NERC reliability region Midwest Reliability Organization (MRO). Nearly all of the Minnesota retail sales are within the Midcontinent Independent System Operator (MISO). The Local Balancing Authorities within MISO, including the Minnesota LBAs, are functionally consolidated.

Prior studies of relevance include the 2006 Minnesota Wind Integration Study[2], the 2007 Minnesota Transmission for Renewable Energy Standard Study[3], the 2009 Minnesota RES Update, Corridor, and Capacity Validation Studies, the 2008 and 2009 Statewide Studies of Dispersed Renewable Generation[4], the 2010 Regional Generation Outlet Study, the 2011 Multi Value Project Portfolio Study, the 2013 Minnesota Biennial Transmission Project Report[5], the 2013 MISO Transmission Expansion Plan, and recent and ongoing MISO transmission expansion planning work[6] .

2.2 Objectives

1. Evaluate the impacts on reliability and costs associated with increasing Renewable Energy to 40% of Minnesota retail electric energy sales by 2030, and to higher proportions thereafter;

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1 MN Laws 2013, Chapter 85 HF 729, Article 12, Section 4; MPUC Docket No. CI-13-486.

2 2006 MN Wind Integration Study. Prepared for the MPUC, Nov 2006. Final Report Volumes I & II, Final Report Presentation. http://www.puc.state.mn.us/PUC/electricity/013752

3 "Minnesota RES Update Study Technical Report." March 2009. "RES Transmission Report." November 2007. "Southwest Twin Cities – Granite Falls Transmission Upgrade Study Technical Report." March 2009. "Capacity Validation Study Report." March 2009. http://www.minnelectrans.com/reports.html

4 Dispersed Renewable Generation Studies. June 2008 and September 2009. http://mn.gov/commerce/energy/topics/resources/Reports-Data/Energy-Reports.jsp

5 http://www.minnelectrans.com/, November 1, 2013.

6 https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx

2. Develop a conceptual plan for transmission necessary for access to regional geographic diversity and regional system flexibility;
3. Identify and develop options to manage the impacts of the renewable energy resources;
4. Build upon prior wind integration studies and related technical work; Coordinate with recent and current regional power system study work;
5. Produce meaningful, broadly supported results through a technically rigorous, inclusive study process.

2.3 Study Timeline

June – August 2013

Commerce: Reviewed prior and current studies and worked with stakeholders and study participants to identify key issues, began development of a draft technical study scope, and accepted recommendations of qualified Technical Review Committee (TRC) members;

September 2013

Commerce: Held a stakeholder meeting to discuss the objectives, scope, schedule, and process; Commerce appointed the Technical Review Committee;

September / October 2013

Commerce, in consultation with the MN utilities, finalized the study scope;

October 2013

The MN utilities, in consultation with Commerce, identified the technical study team;

November 2013 – October 2014

The study was completed. The Technical Review Committee has reviewed all technical work in this study on an ongoing basis, throughout the study.

2.4 Study Scope

This study is focused on the reliability impacts of increased levels of variable renewables (wind and solar generation) and the associated costs of those impacts.

MRITS builds upon prior wind integration studies and related technical work and is coordinated with recent and current regional power system study work. The study scope was developed from statutory guidance, stakeholder input, and technical study team refinement.

MRITS incorporates three core and interrelated analyses: 1) *Power flow analysis* for development of a conceptual transmission plan, which includes transmission necessary for generation interconnection and delivery and for access to regional geographic diversity and regional supply and demand side flexibility; 2) *Production simulation analysis* for evaluation of operational performance, including reserve violations, unserved load, wind / solar curtailments, thermal cycling, and ramp rate and ramp range, and, to screen for challenging time periods; and 3) *Dynamics analysis*, which includes transient stability analysis and weak system strength analysis.

The MRITS study area is Minnesota-centric, which focuses on the combined operating areas of the Minnesota utilities and transmission companies, in the context of the MISO North/Central areas and the neighboring regions to the west and north.

The base study models (baseline and scenarios) are coordinated with and consistent with MISO models and databases including dispatch to the MISO market. Additional options were considered in Task 7 (Identify & Develop Mitigations / Solutions) as needed.

The key study tasks are:

- Develop Study Scenarios; Site Wind and Solar Generation (Task 1)
- Perform Production Simulation Analysis (Tasks 2 and 4)
- Perform Power Flow Analysis; Develop Transmission Conceptual Plan (Task 3)
- Evaluate Operational Performance (Task 6a)
- Screen for Challenging Periods; Perform Dynamics Analysis (Task 5 and 6b)
- Identify and Develop Mitigations and Solutions (Task 7)

The study task flow chart is shown in Figure 2-1.

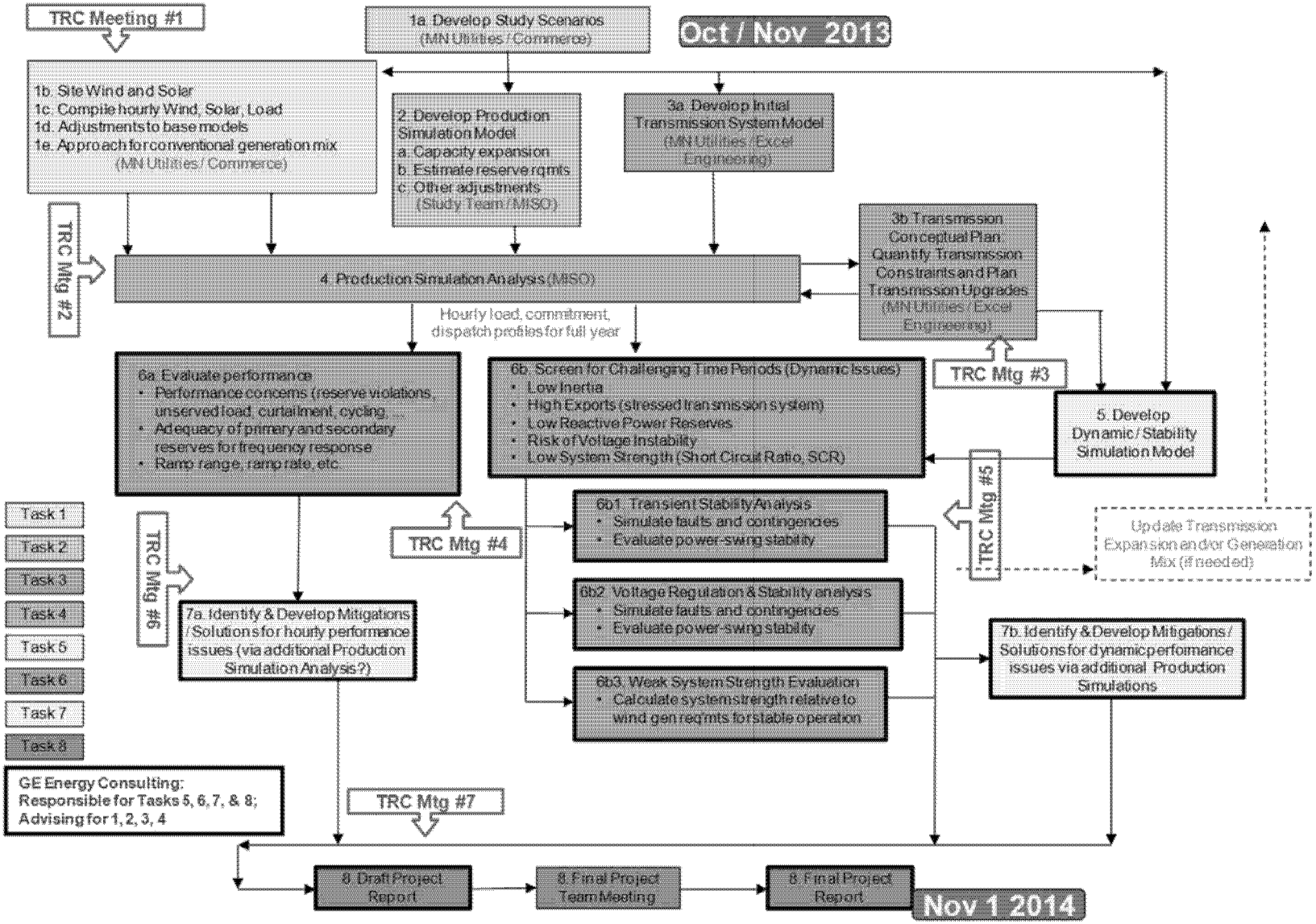

Figure 2-1 Flowchart of Project Tasks

2.5 Study Scenarios

The MRITS study scenarios were developed from statutory guidance, stakeholder input, and technical study team refinement.

The study year of 2028 was selected to help ensure that all models and system data were coordinated with and are consistent with MISO MTEP13 models and databases. It was also thought that 2028 was suitably near to 2030 as written in legislation, especially considering the difficulty in projecting an accurate load forecast fifteen years into the future.

Each of the study scenarios builds on the prior scenario, starting with the Baseline. The Baseline scenario has sufficient renewable energy generation to satisfy the current renewable energy standards and solar energy standards for all states in the study region. For Minnesota, the Baseline scenario was based on current Minnesota utility plans to meet the Minnesota Renewable Energy Standard (RES) and the Solar Energy Standard (SES) with renewable energy (wind, solar, small hydro, biomass, etc.) from the Minnesota-centric area and incorporates refinements from the technical study team. For non-Minnesota MISO states in the study footprint, the Baseline scenario was based on the prior approved 2013 MISO Transmission Expansion Plan (MTEP13).

1. Scenario 1 builds on the Baseline scenario by adding incremental wind and solar (variable renewables) generation to the Baseline model to supply a total of 40% of Minnesota annual electric retail sales from renewables in the study year with all states at full implementation of their current RESs.
2. Scenario 2 builds on Scenario 1 by adding incremental wind and solar generation to the Scenario 1 model to supply 50% of Minnesota electric retail sales from total renewables and by further adding incremental wind and solar generation to supply an additional 10% of the non-Minnesota MISO North / Central retail electric sales from total renewables (i.e. to increase the MISO footprint renewables 10% above full implementation the current RESs).

Model	Minnesota	MISO North/Central (includes MN)
Baseline	28.5%	14.0%
Scenario 1	40.0%	15.0%
Scenario 2	50.0%	25.0%

Within each of the scenarios, the allocation of the RES was further divided between wind and solar resources and within the solar allocation was divided between centralized utility sized solar (UPV) and distributed small PV (DPV).

It was assumed that the growth in energy sales for Minnesota and MISO (includes Minnesota) would increase by 0.5% and 0.75% respectively. Given these assumptions and the allocation of resources for each scenario, Table 2-1 describes the amount of additional wind and solar resources included in the models.

Table 2-1 Wind and Solar Resource Allocations for Study Scenarios

	2013	2028				
MN Retail Sales (GWH)	66,093	71,227				
		Wind MW		PV MWac		
Minnesota-centric	**Wind (MW)**	**Total**	**Incremental**	**Total**	**Incremental**	
Existing + signed GIA	8,922				**UPV**	**DPV**
Baseline		5,990		457	361	96
Scenario 1		7,521	1,931	1,371	723	191
Scenario 2		8,131	610	4,557	2,756	430

	2013	2028				
MISO Retail Sales (GWH)	498,000	557,000				
		Wind MW		PV MWac		
MISO (includes Minnesota)	**Wind (MW)**	**Total**	**Incremental**	**Total**	**Incremental**	
Existing + signed GIA	15,320				**UPV**	**DPV**
Baseline		22,229	6,900	1509	1,413	96
Scenario 1		24,160	1,931	2,442	723	210
Scenario 2		37,796	13,636	6,201	5,636	565

Note that Minnesota Baseline renewable percentage includes qualifying small hydro and biomass. MISO retail sales and percentages are MISO North and Central (they do not include MISO South).

Minnesota wind generation was sited Minnesota-centric (Minnesota, North Dakota, South Dakota, and northern Iowa). Minnesota solar generation was sited in Minnesota, eastern South Dakota and northern Iowa. MISO wind and solar generation was sited per the MISO Transmission Expansion Planning assumptions. The generation siting process and assumptions are described in greater detail in subsequent sections of this report.

3 WIND AND SOLAR GENERATION SITING

Per the project plan, this task focused on selecting sites for wind and solar resources to meet the requirements of the study scenarios. Minnesota wind and solar resources were sited in the Minnesota-centric area (MN, ND, SD, northern Iowa) based on existing wind and solar, planned wind and solar (including those with signed Interconnection Agreements, wind sites in MVP portfolio planning), and MN utility announced projects. Wind and solar resources in the interconnection queues also helped inform the siting selection process.

MISO future wind and solar was sited per MTEP guidelines (e.g. at expanded RGOS zones on a pro rata basis).

As described in the previous chapter, there are significant amounts of new wind and solar generation to locate in Minnesota and within MISO for the study scenarios. Table 3-1 and Table 3-2 show the Minnesota and MISO wind and solar build-outs for the Baseline, Scenario 1 and Scenario 2 cases to be studied. Table 3-3 shows the key assumptions that were used during the build-out process.

Table 3-1 Minnesota-Centric Wind and Solar Amounts to be Sited

	Minnesota Centric			
	Wind MW	PV MWac		
	Incremental	Incremental		
		Utility PV	Distributed PV	Total
Baseline		361	96	457
Scenario 1	1,931	723	191	914
Scenario 2	610	2,756	430	3186

Table 3-2 Non-MN-Centric Wind and Solar Amounts to be Sited

	Non-MN MISO			
	Wind MW	PV MWac		
	Incremental	Incremental		
		Utility PV	Distributed PV	Total
Baseline	6900	1052	0	1052
Scenario 1	0	0	19	19
Scenario 2	13026	2,880	135	3015

Table 3-3 Key assumptions for Wind & Solar Build-Outs

Wind Annual Capacity Factor	Utility Scale PV Central CPV fraction	Utility Scale PV Central CPV Annual Capacity Factor (AC)	Residential & Commercial PV Distributed DPV fraction	Residential & Commercial PV Distributed DPV Annual Capacity Factor (AC)	
Minnesota					**MN**
38%					existing
38%	80%	18%	20%	17%	**Baseline**
42%	80%	18%	20%	17%	**S1**
42%	85%	18%	15%	17%	**S2**
MISO					**MISO**
32%					existing
37%	90%	17%	10%	16%	**Baseline**
37%	90%	17%	10%	16%	**S1**
37%	90%	17%	10%	16%	**S2**

PV assumptions:
- S1 20% distributed, 80% centralized
- S2 15% distributed, 85% centralized

3.1 Siting for Wind Resources

The wind profile data used in this study were derived from existing wind data sets from NREL. The data set are for the years, 2004, 2005 and 2006 and was initially developed for Eastern Wind Integration and Transmission Study (EWITS) and updated for Eastern Renewable Generation Integration Study (ERGIS) on hourly and 10 minutes intervals. MISO had been using the data set year 2005 but downloaded and updated their data using the updated ERGIS 2006 data set.

MISO also added recently signed Generation Interconnection Agreements for Xcel Energy and MidAmerican Energy Company (MEC) wind generation projects and these reduced the MN, ND & IA future/proxy wind to compensate for the addition. MISO also minimized wind siting at RGOS Zones

MN-E, MN-H, MN-L, WI-F and allowed non-MN MISO wind, to serve non-Minnesota MISO state RPSs, to include MN sited wind generation. The MISO wind was then prorated on the projected 2018, 2023 and 2028 additions. Bus names and bus numbers were corrected accordingly.

3.1.1 Minnesota Wind

Minnesota Wind is intended to serve the Minnesota RES and is sited in the Minnesota-centric area which includes all of Minnesota, parts of North Dakota and South Dakota as well as northern Iowa.

A For the Baseline Model

MTEP13 siting principles which uses the current MISO state RPSs, and corresponding wind siting including the existing and planned wind sites. (Table 3-4)

B For Scenario 1

Adding 1931 MW into the Minnesota-centric area and sited per Minnesota wind resource and consistent with expanded MISO renewable energy (MVP/RGOS) zones (see Table 3-5). Xcel Energy had recently signed Generation Interconnection Agreements for four wind plants totaling 750 MW and this was included in the 1931 MW and these locations are shown in green in Figure 3-2.

C For Scenario 2

Minnesota wind for Scenario 2 was increased by 610 MW above what was in Scenario 1. See Table 3-6.

3.1.2 MISO (non-MN) Wind

Non-MN Wind is intended to serve the MISO state RPSs for states other than Minnesota. The wind resources are sited per MTEP wind resource in the MISO footprint including in the Minnesota-Centric Area.

A For Baseline

Beyond the wind included in the MTEP 2013 models, which includes the existing and planned wind projects in MISO, 6900 MW was added MISO wide to meet the current MISO state RPSs (including MN). This is shown in Table 3-2.

B For Scenario 1

No non-MN MISO wind was added.

C For Scenario 2

Beyond the Baseline, 13,026 MW of non-Minnesota wind was added baseline in the RGOS zones primarily in Iowa, Illinois, Indiana and Michigan (see Table 3-8). MEC had recently signed generation interconnection agreements for four wind plants totaling 932.6 MW and this was included in the 13,026 MW total. These four locations are shown in green in Figure 3-3.

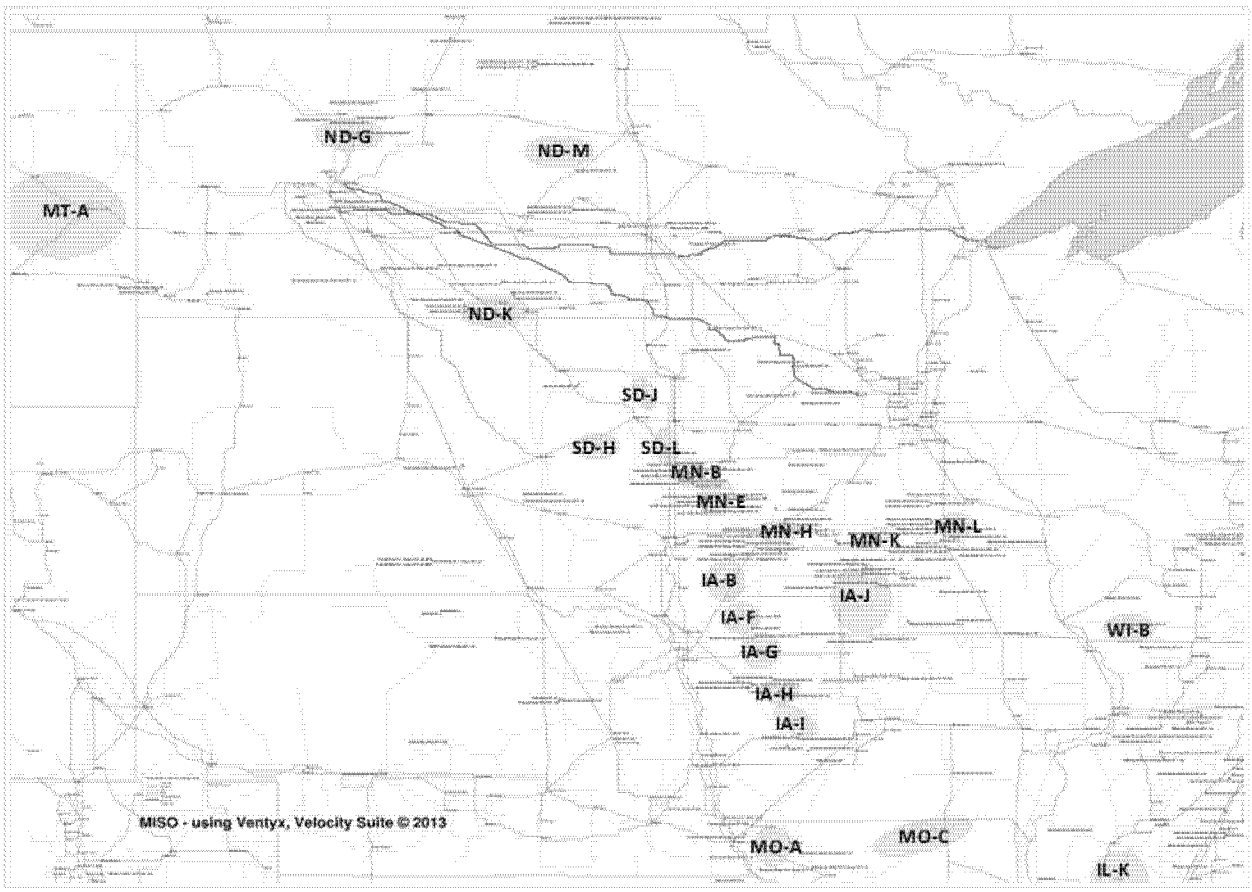

Figure 3-1 RGOS Wind Zones

Table 3-4 MISO Wind Locations-Baseline

RGOS Zone	Bus Name	Existing and Signed GIAs (MW)	MISO - Baseline Wind Additions (MW)			Total wind amounts in Baseline Scenario (MW)
			2018	2023	2028	
IA-B	SHELDON	610	23	63	239	934
IA-F	SHELDON	675	23	61	233	992
IA-G	RAUN	805	21	56	214	1096
IA-H	GRIMES	415	17	45	170	647
IA-I	GRIMES	383	10	26	101	520
IA-J	WEBSTER	1735	1	4	14	1754
IL-F	BROKAW	891	126	48	21	1085
IL-K	PAWNEE	420	94	71	0	585
IN-E	WESTWD	350	11	30	115	507
IN-K	HORTVL	200	15	40	154	409
MI-B	REESE	305	378	0	0	683
MI-C	WYATT	233	345	0	0	579
MI-D	WYATT	112	278	0	0	390
MI-E	REESE	333	378	0	0	711
MI-F	WYATT	32	378	0	0	410
MI-I	PALISADES		191	0	0	191
MN-B	LYON COUNTY	985	6	16	60	1066
MN-E	CHANARAMBIE	891				891
MN-H	LAKEFIELD	553				553
MN-K	HUNTLEY	1251	14	36	140	1441
MN-L	PLEASANT VALLEY	813				813
MO-A	ATCHISON T	146	224	0	0	370
MO-C	ADAIR		314	0	0	314
MT-A	BAKER	200	11	28	107	345
ND-G	GRE-MCHENRY	780	16	41	156	994
ND-K	ELLENDALE	171	13	34	130	348
ND-M	GRE-RAMSEY	887	4	12	48	952
SD-H	BIG STONE SOUTH (West of)		23	63	239	324
SD-J	BIG STONE SOUTH	40	23	61	232	355
SD-L	BROOKINGS	207	23	63	239	531
WI-B	DUBUQUE CTY	121	18	49	186	374
WI-D	NORTH APPLETON	267	20	54	203	543
WI-F		520.6	0	0	0	521
	Totals	**15,329**	**3000**	**900**	**3000**	**22,229**

Table 3-5 Incremental Minnesota-Centric Wind Locations for Scenarios 1&2

RGOS Zone	Bus Name	Incremental MN Wind for Scenario 1	Incremental MN wind for Scenario 2	Total Scenario 1 & 2 Incremental MN wind
IA-B	SHELDON	125	50	175
IA-J	WEBSTER	75	10	85
MN-B	LYON COUNTY	218	191	409
MN-E	CHANARAMBIE	50		50
MN-H	LAKEFIELD	125		125
MN-K	HUNTLEY	150	129	279
MN-L	PLEASANT VALLEY	75		75
MN	ODELL (G826)	200		200
MN	PLEASANT VALLEY (J278)	200		200
ND-G	GRE-MCHENRY	0	80	80
ND-K	ELLENDALE	50		50
ND-M	GRE-RAMSEY	25	30	55
ND	BORDERS (J290)	150		150
ND	COURTNEY (J262/J263)	200		200
SD-H	BIG STONE SOUTH (West of)	50		50
SD-J	BIG STONE SOUTH	108	50	158
SD-L	BROOKINGS	130	70	200
	Totals	**1931**	**610**	**2541**

Table 3-6 Minnesota-Centric Wind Siting

State	Baseline Scenario	Incremental MN Wind gen for Scenario 1	Incremental MN Wind gen for Scenario 2	Total Incremental Wind Scenario 1 & 2
IA %	24.5%	10.4%	9.8%	10.2%
MN %	**43.5%**	**52.7%**	**52.5%**	**52.7%**
ND %	20.9%	22.0%	18.0%	21.1%
SD %	11.1%	14.9%	19.7%	16.1%

Table 3-7 Non Minnesota MISO Wind Locations- Scenario 1 & 2

RGOS Zone	Bus Name	Incremental Non-MN Wind for Scenario 1	Incremental Non-MN Wind for Scenario 2
IA-B	SHELDON		361
IA-F	SHELDON		397
IA-G	RAUN		350
IA-H	GRIMES		240
IA-I	GRIMES		67
IA-J	WEBSTER		25
IA	HIGHLAND (R39)		500
IA	LUNDGREN (R42)		250
IA	VIENNA II (H009)		44
IA	WELLSBURG (H021)		138.6
IL-F	BROKAW		398
IL-K	PAWNEE		345
IN-E	WESTWD		329
IN-K	HORTVL		425
MI-B	REESE		736
MI-C	WYATT		676
MI-D	WYATT		552
MI-E	REESE		736
MI-F	WYATT		736
MI-I	PALISADES		391
MN-K	HUNTLEY		261
MO-A	ATCHISON T		453
MO-C	ADAIR		620
MT-A	BAKER		309
ND-G	GRE-MCHENRY		353
ND-K	ELLENDALE		367
ND-M	GRE-RAMSEY		130
SD-H	BIG STONE SOUTH (West of)		638
SD-J	BIG STONE SOUTH		571
SD-L	BROOKINGS		568
WI-B	DUBUQUE CTY		507
WI-D	NORTH APPLETON		550
WI-F			0
	Totals	**0**	**13,026**

Table 3-8 Non-MN MISO Wind Siting

State	Baseline Scenario	Incremental Non-MN Wind for Scenario 1	Incremental Non-MN Wind for Scenario 2
IA %	26.7%	n/a	18.2%
IL %	7.5%	n/a	5.7%
IN %	4.1%	n/a	5.8%
MI %	13.3%	n/a	29.4%
MN %	**21.4%**	n/a	**2.0%**
MO %	3.1%	n/a	8.2%
MT %	1.6%	n/a	2.4%
ND %	10.3%	n/a	6.5%
SD %	5.4%	n/a	13.6%
WI %	6.5%	n/a	8.1%

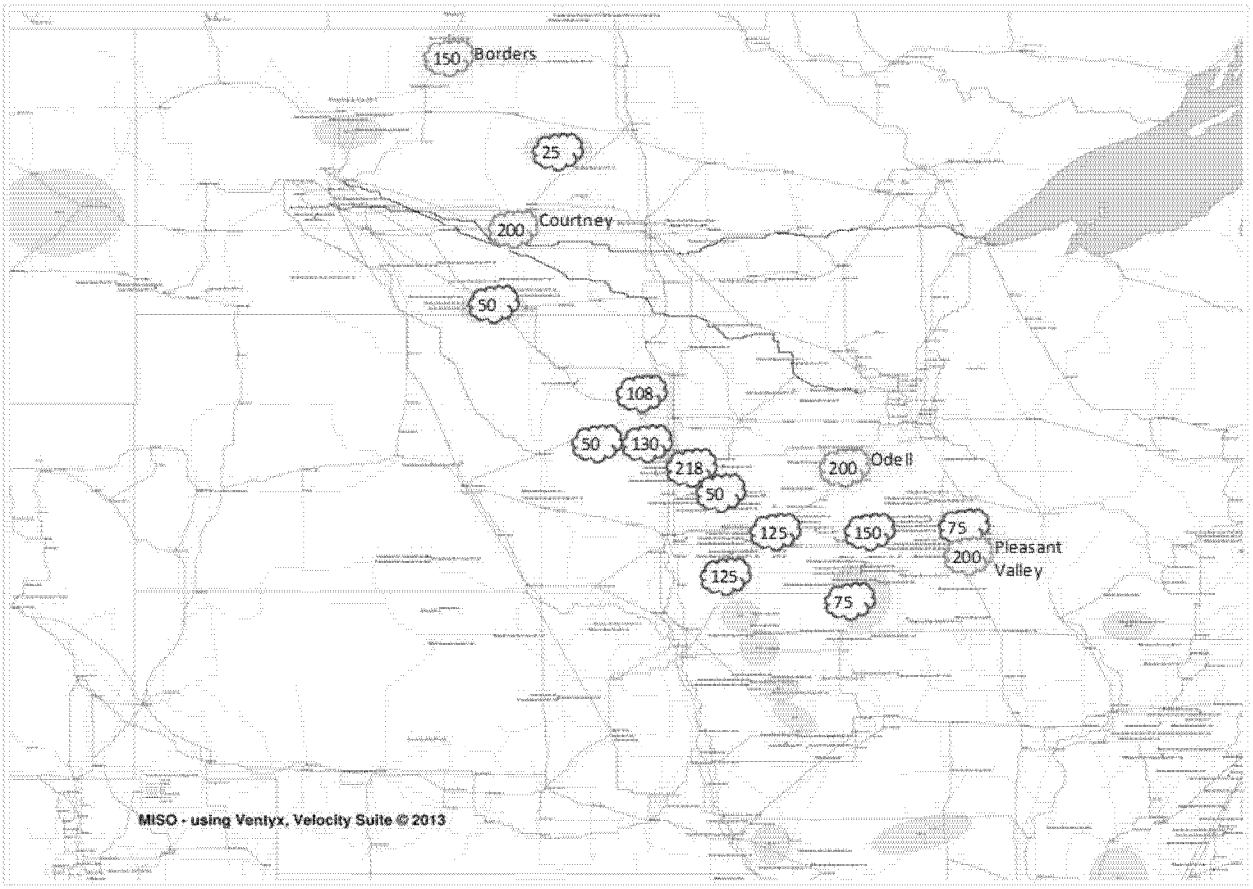

Figure 3-2 MN & Non MN Scenario 1 Wind Siting

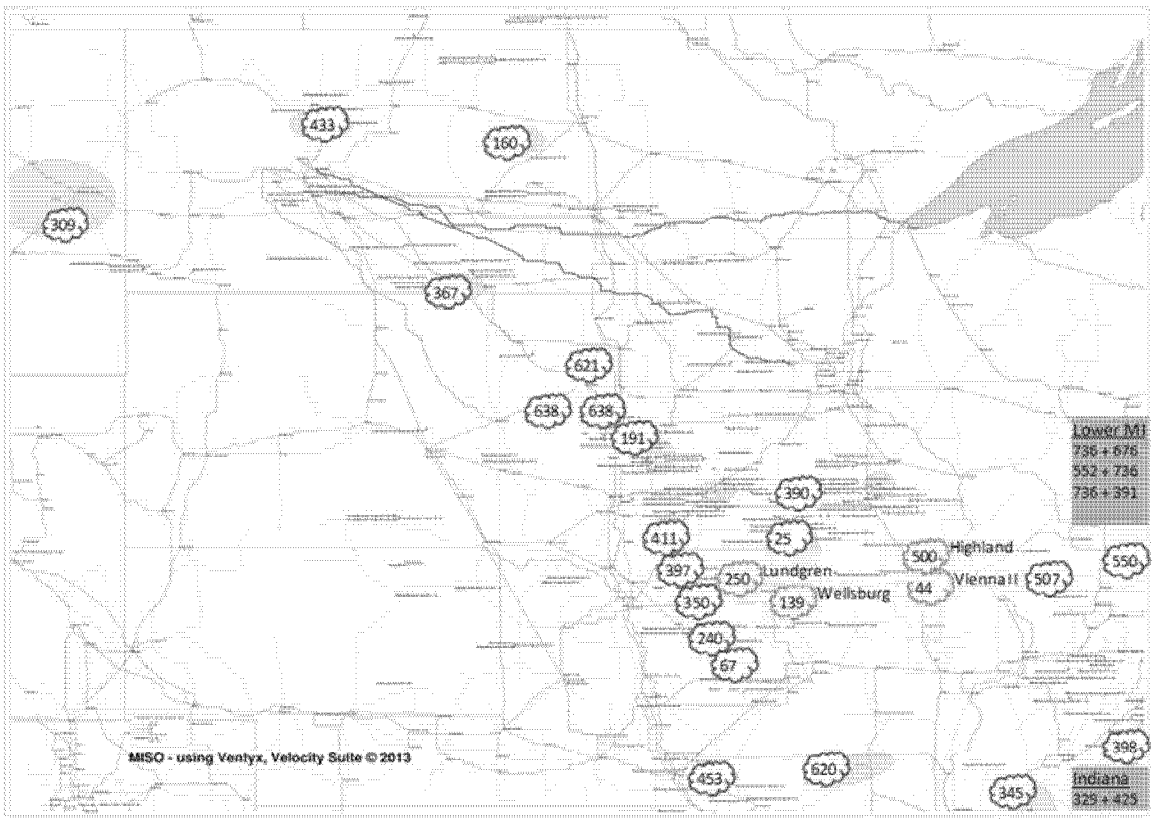

Figure 3-3 RGOS Wind Zones w/MN & Non MN Scenario 2

3.2 MISO Wind Reassignment

The Non-MN MISO wind was sited per as described in the previous section. However after the production simulation analysis showed significant amounts of wind congestion at some plants in western MISO, it was decided to relocate some of this congested wind sites to less congested areas. A portion of the wind generation was moved from the "Top 4" congested sites and reassigned to the "Bottom 10" least congested sites.

This reassigned generation only involved the non-MN MISO wind and this generally relocated the wind generation to the south and east locations with lower capacity factor. As a result of the placing this generation at sites with lower capacity factors, or reduced average wind speeds, the wind nameplate had to be increased in order to maintain the equivalent wind energy prior to and after the shift.

Table 3-9 displays the shifted sites, nameplate capacity and annual energy outputs. Figure 3-4 shows the locations of the wind sites that were shifted; the sites in red represent the 4 most congested sites. The wind resources from these locations were shifted to the sites shown in yellow.

Table 3-9 Wind Shift from the 4 Most-Congested to the 10 Least-Congested Sites

Zone	Company	Basecase (MW)	S1 (MW)	S2 (MW)	Basecase Curtailment (GWh)	S1 Curtailment (GWh)	S2 Curtailment (GWh)	S2 Capacity Adjustment (M	S2 Energy Adjustment (GWh)
SD-H:1	OTP	324	374	1,012	25.7	0.9	1,226.6	(311)	(1,229)
ND-K:1	MDU	177	227	595	5.0	26.3	895.2	(293)	(898)
IA-G:1	MEC	292	292	642	0.6	1.7	495.6	(129)	(499)
MN-K:1	Alliant West	190	340	731	3.7	30.9	444.4	(118)	(447)
								(851)	**(3,293)**
H009:1	MEC	-	-	44	-	-	0.3	83	329
H021:1	Alliant West	-	-	139	-	-	0.1	97	329
IL-F:1	Ameren IL	194	194	591	-	-	-	106	329
IN-E:1	Duke Energy IN	157	157	486	-	-	-	103	329
MI-C:1	Detroit Edison	345	345	1,022	-	-	-	111	329
MI-B:1	Detroit Edison	378	378	1,114	-	-	-	89	329
MI-F:1	Detroit Edison	378	378	1,114	-	-	-	98	329
MI-E:1	Detroit Edison	378	378	1,114	-	-	-	80	329
MI-I:1	Consumers Energy	191	191	582	-	-	-	84	329
MI-D:1	Detroit Edison	278	278	830	-	-	-	96	329
								947	**3293**
							Net	**96**	**0**

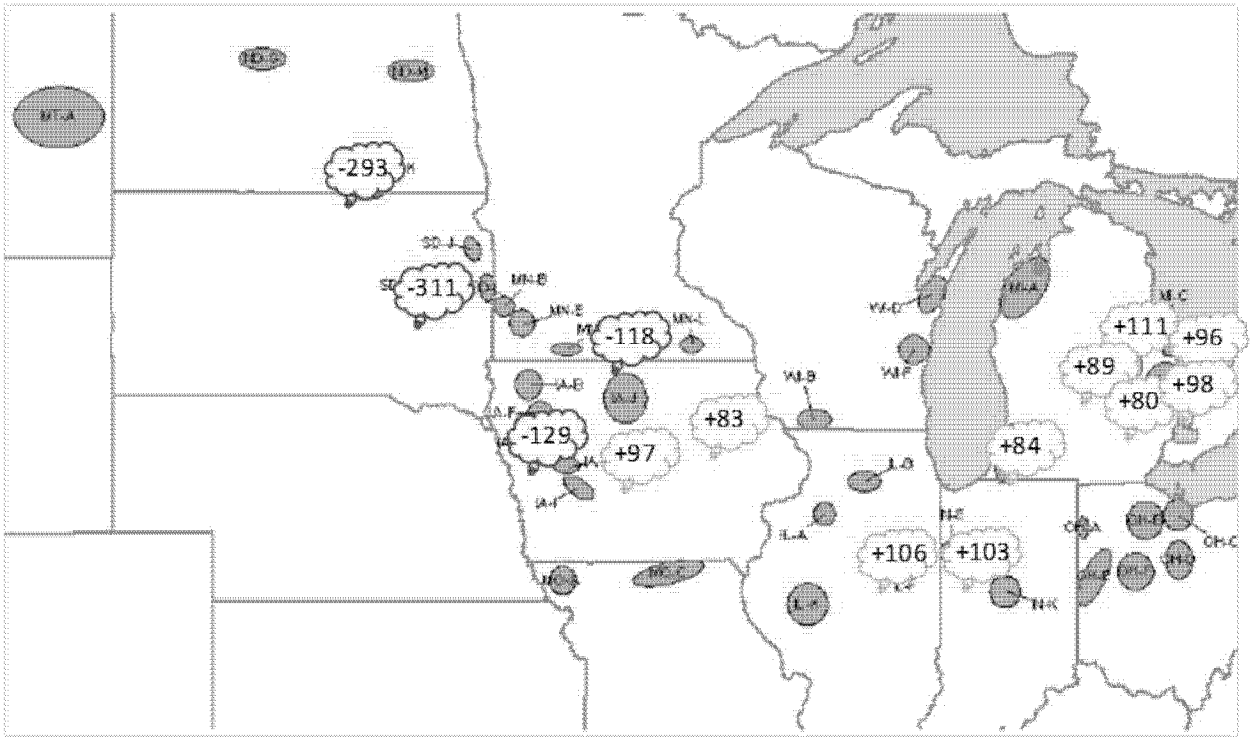

Figure 3-4 Wind Shift from the 4 Most-Congested to the 10 Least-Congested Sites

3.3 Siting of PV Solar Resources

The Non-Minnesota MISO photovoltaic solar data set came from the ERGIS hourly solar data. For Minnesota solar data, NREL developed additional 2006 hourly solar power data with 10 km resolution, which allow the siting of additional utility-scale solar in Minnesota that was not present in the ERGIS data.

For utility-scale solar plants in Minnesota, the data was processed to create individual solar plants simulating a 1.25:1 module-to-inverter ratio. This was done to approximate the additional solar panels that are used to reduce the losses and increase the capacity factor of utility-scale solar plants by having the capacity of the photovoltaic panels exceed the capacity of the inverter. This process involved setting the ac rating at 80% of the dc nameplate rating and clipping the output to the ac rating. (For example, the raw values for a 50 MWdc PV plant were limited to 40 MWac to create a 40 MW plant for the study.) The capacity values were revised accordingly so they reflect the ac bus bar values.

The ERGIS data already contained values for the utility-scale solar plants outside of Minnesota and the distributed solar (both inside and outside of Minnesota). These values reflected typical losses due to inverter efficiency and other factors. The distributed solar dc to ac losses varied from 79% to 85% with an average of 82%. Non-Minnesota utility-scale solar losses varied from 77% to 89% with an average of 83%. However the assumed annual energy numbers remain the same because the ac ratings are based on the maximum output value for each site rather than the dc values.

3.3.1 Minnesota PV Solar

The solar generation added in the Minnesota-Centric area was split between Distributed PV and Centralized utility scale PV on a 20%/80% basis for the Baseline and Scenario 1, and a 15%/85% split for Scenario 2, respectively. The 1.5% solar mandate enacted in 2013 legislation dictated that at least 10% of the solar was to be distributed, but the splits were determined in the stakeholder study scoping process. The distributed PV was assumed to be sited at load centers.

The Centralized utility scale PV was spread by solar resource largely over the southern half of Minnesota, however there was some sited in the northern portion of the state as utilities in the northern part of the state indicated that they would prefer to site closer to their service territory even knowing that the energy output would be slightly less than the southwest portion of the state. Note: there is an approximately 10% decrease in solar resource strength from the south west corner of MN to Duluth, MN in the north east. The solar strength does not follow an intuitive rule where further south equals stronger solar strength, but rather the solar strength gradient generally follows a NW to SE line, such that Alexandria, MN has about the same solar value as the Twin Cities. This is shown in Figure 3-5.

Figure 3-5 United States Photovoltaic Solar Resource (portion of)

- For the Baseline scenario, a total of 457 MWac PV was added with 96 MW being distributed and 361 MW classified and sited as Utility scale solar.
- For Scenario 1, a total of 914 MWac PV was added with 191 MW being distributed and 723 MW classified and sited as Utility scale solar.
- For Scenario 2, a total of 3,186 MWac PV was added with 430 MW being distributed and 2,756 MW classified and sited as Utility scale solar.

These solar generation amounts are shown in Table 3-10 and Table 3-11. The locations are shown in Figure 3-6, Figure 3-7, and Figure 3-8.

Table 3-10 Minnesota Utility PV Sites for Study Scenarios

Location	Baseline	Scenario 1	Scenario 2	Total at each site
Riverton 230	2	5	5	12
Badoura 230	3	8	10	21
Hubbard 230	5	10	15	30
Wing River 230	5	10	15	30
Alexandria 345	20	20	50	90
Quarry 345		30	80	110
Chub Lake 345	20	20	100	140
Prairie Island 345		30	100	130
North Rochester 345		30	100	130
Byron 345	20	20	100	140
Pleasant Valley 345	20	30	100	150
Sheas Lake 345	20	30	100	150
Owatanna 115			50	50
Wilmarth 345		50	100	150
Adams 345	20	30	100	150
Hayward 161			51	51
Cedar Mountain 345	20	30	100	150
Willmar 230			80	80
Big Stone South 345	20	30	100	150
Hazel 345	20	30	100	150
Lyon County 345	20	30	100	150
Fort Ridgley 115			50	50
Chanarambie 115			50	50
Fox Lake 161			50	50
Winnebago(Huntley) 345	30	40	100	170
Brookings 345	26	40	100	166
West New Ulm 115			50	50
Lakefield 345	30	40	100	170
Pipestone 115			50	50
Nobles 345	30	40	100	170
Split Rock 345	30	40	150	220
Ledyard, IA 345		40	200	240
Obrien, IA 345		40	200	240
Totals	**361**	**723**	**2756**	**3840**

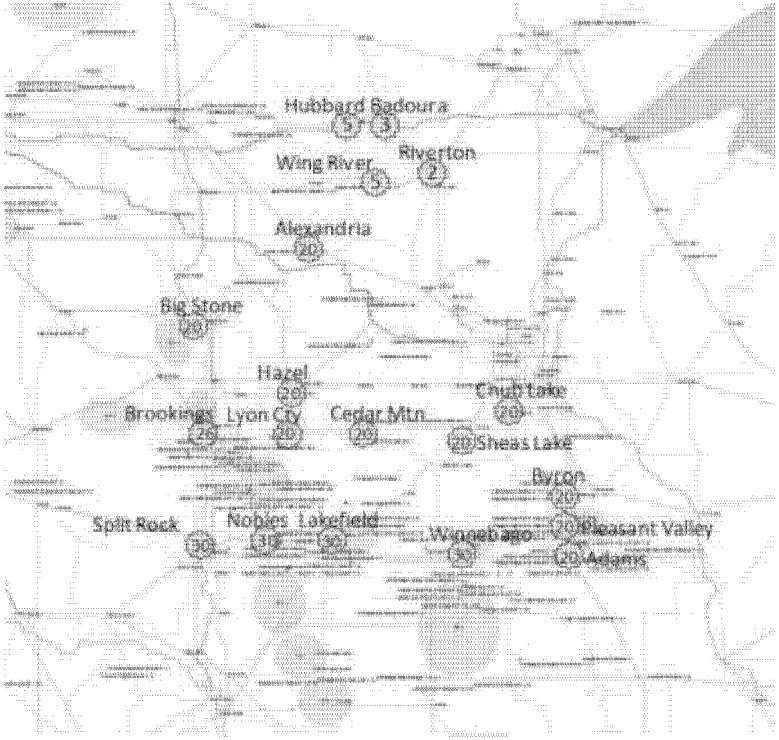

Figure 3-6 MN Solar for Utility Locations - Baseline

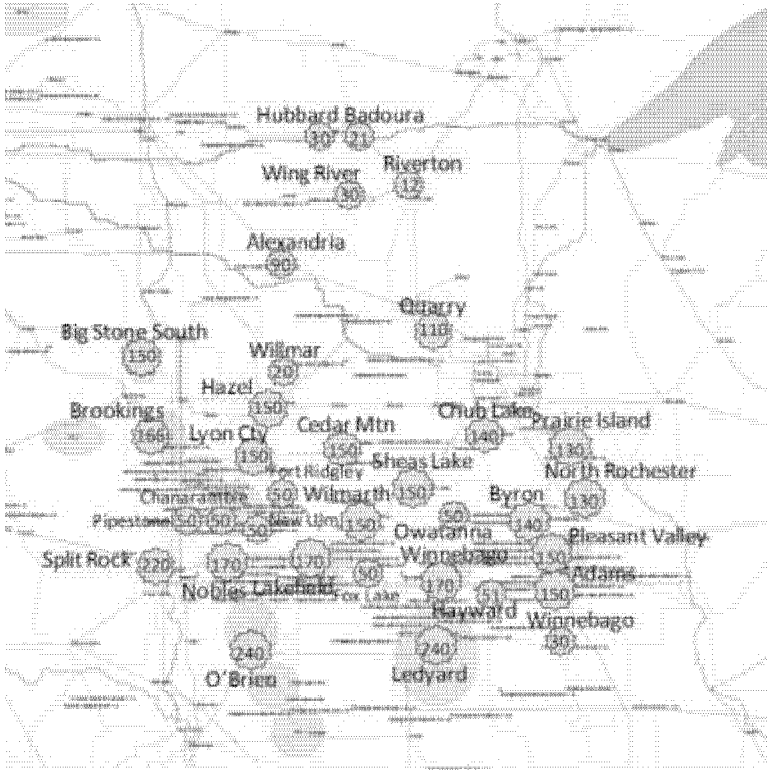

Figure 3-7 MN Solar for Utility Locations - All Scenarios

Table 3-11 MN Distributed PV Sites for Study Scenarios

Location	Baseline	Scenario 1	Scenario 2	Total at each site
	MW (AC)			
NORTHERN HILLS	4	6	15	25
SOUTH FARIBAULT	2	4	9	15
CANNON FALLS	3	9	21	33
INVER HILLS	6	12	28	46
BLUE LAKE	4	9	18	31
GRE-MCLEOD	3	5	13	21
TERMINAL	9	34	30	73
PARKERS LAKE	14	24	92	130
AS KING	8	14	32	54
BLAINE	3	6	14	23
COON CREEK	8	10	24	42
DICKINSON	4	7	16	27
ELM CREEK	2	4	9	15
KOLMAN LAKE	4	7	16	27
BLAINE	4	7	16	27
ELK RIVER	4	7	16	27
ELM CREEK	2	4	9	15
CHISAGO	4	7	16	27
SHERBURNE CTY	3	5	13	21
RUSH CITY	2	3	7	12
PAYNESVILLE	3	7	16	26
Totals	**96**	**191**	**430**	**717**

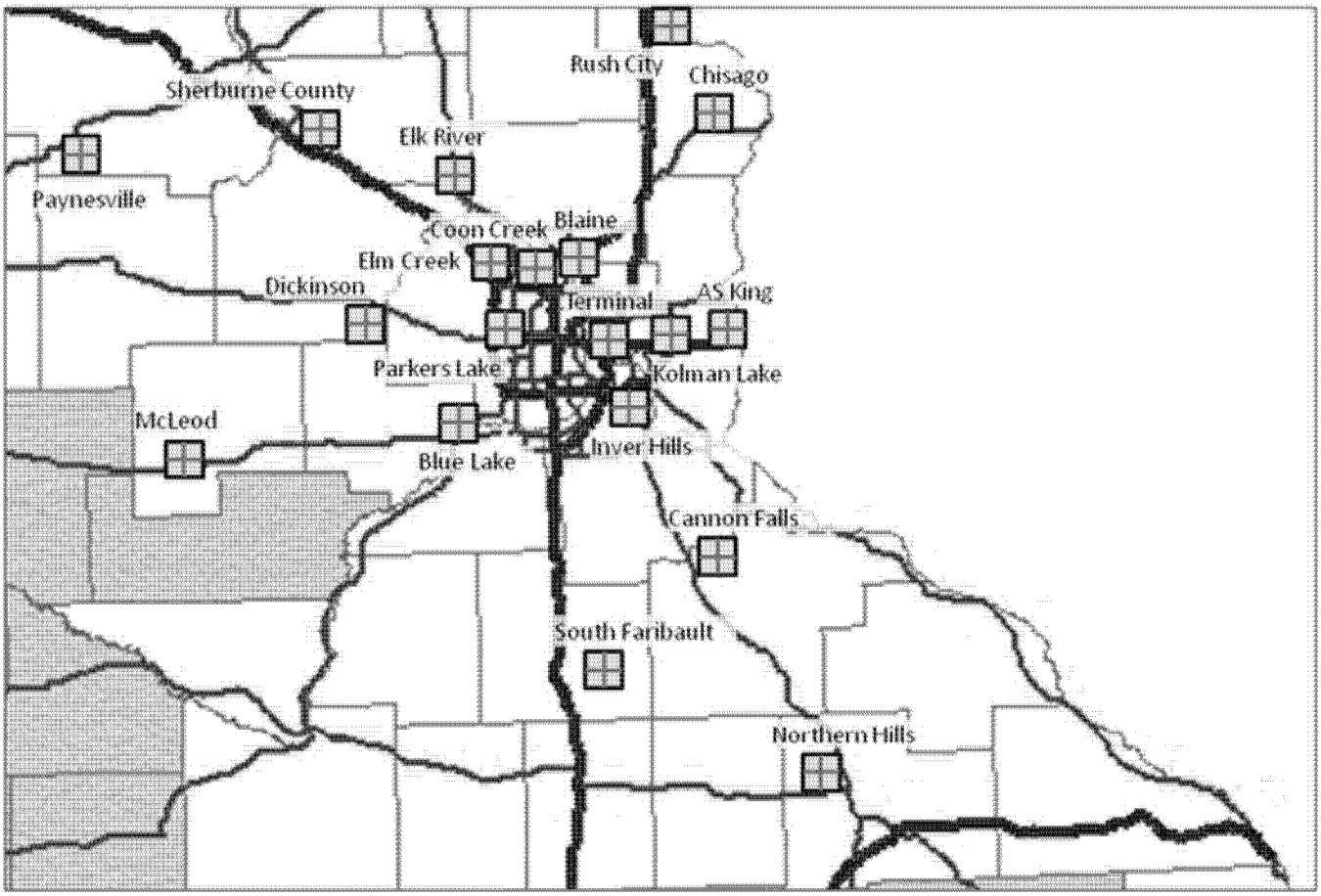

Figure 3-8 MN Distributed PV Sites

3.3.2 Non-Minnesota PV Solar

MISO solar was sited at ERGIS solar data set locations with a fixed 10%/90% split between Distributed PV and Central utility scale PV and this split was also determined in the stakeholder study scoping process.

- For the Baseline no solar was added.
- For Scenario 1, a total of 19 MWac of distributed PV was added.
- For Scenario 2, a total of 3,015 MWac PV was added with 135 MW being distributed and 2,880 MW classified and sited as Utility scale solar.

These solar generation amounts are shown in Table 3-12 and Table 3-13. The locations are shown in Figure 3-9.

Table 3-12 Non-MN Solar for Utility Locations

State	Baseline	Scenario 1	Scenario 2	Total at each site
	MW (AC)			
Michigan	126	0	189	**315**
Indiana	239	0	521	**681**
Illinois	188	0	377	**572**
Iowa	39	0	55	**94**
Missouri	431	0	1583	**2079**
Arkansas	7	0	39	**48**
Kentucky	22	0	116	**143**
Totals	**1052**	**0**	**2880**	**3932**

Table 3-13 Non-MN Distributed Solar for Study Scenarios

Location		Baseline	Scenario 1	Scenario 2	Sub-totals	Totals
	City	MW (AC)				
MI	Detroit	0	1	6	7	31
	Flint	0	0	4	4	
	Grand Rapids	0	1	6	7	
	Ann Arbor	0	1	6	7	
	Lansing	0	1	5	6	
IN	Indianapolis	0	1	6	7	26
	Evansville	0	1	6	7	
	Fort Wayne	0	1	6	7	
	South Bend	0	0	5	5	
IL	Rockford	0	1	7	8	22
	Champaign	0	1	6	7	
	Peoria	0	0	3	3	
	Springfield	0	1	3	4	
Wi	Milwaukee	0	0	6	6	22
	Madison	0	0	4	4	
	Kenosha	0	1	4	5	
	Green Bay	0	1	6	7	
IA	Des Moines	0	1	6	7	26
	Cedar Rapids	0	1	5	6	
	Sioux City	0	1	5	6	
	Davenport	0	1	6	7	
MO	St Louis	0	1	6	7	27
	St Charles	0	1	6	7	
	St Peters	0	1	6	7	
	O'Fallon	0	0	6	8	
	Totals	**0**	**19**	**135**	**154**	**154**

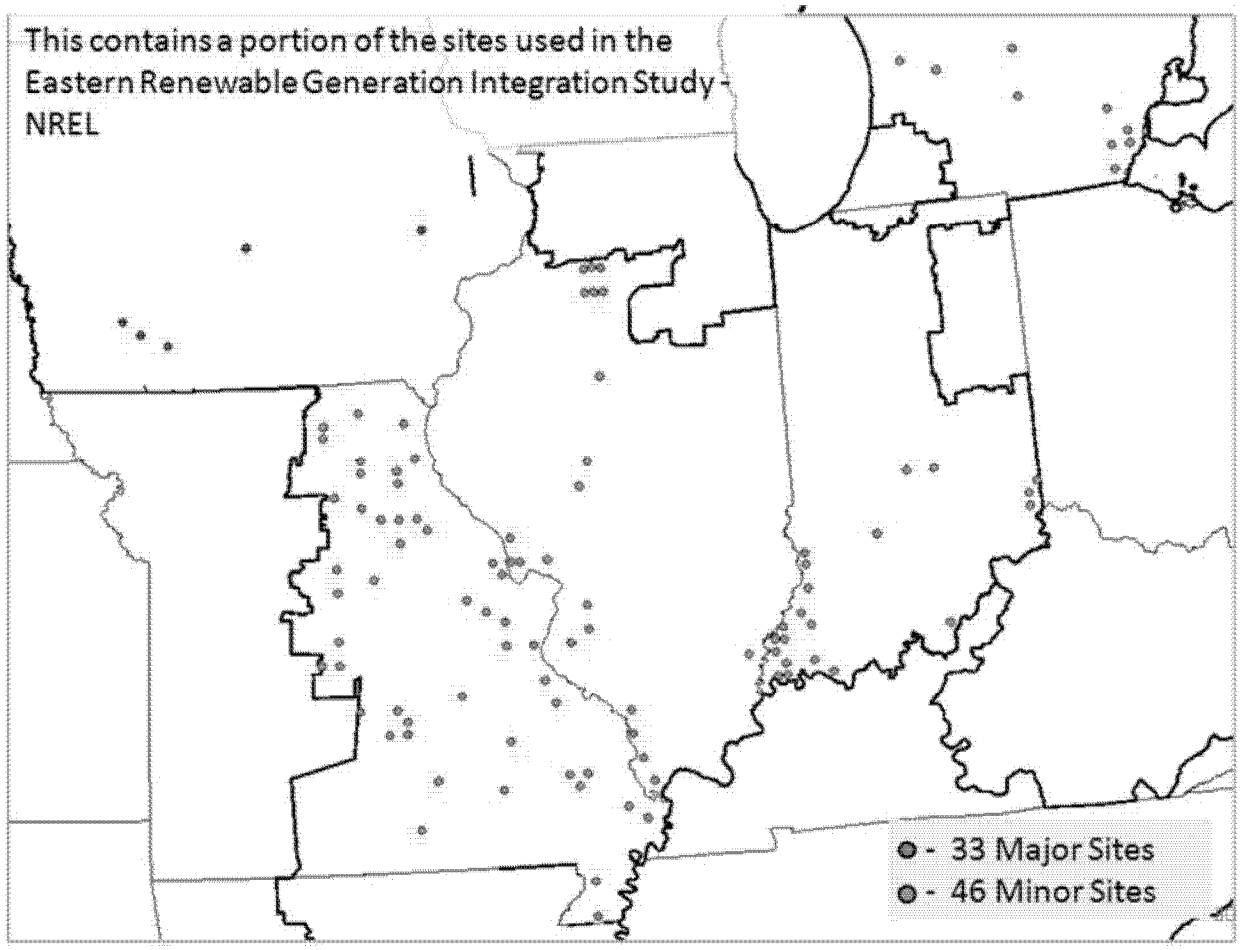

Figure 3-9 Locations of Non-MN Solar - Utility Locations

4 TRANSMISSION SYSTEM CONCEPTUAL PLANS

In 2013, the Minnesota Legislation adopted a requirement that all electrical utilities and transmission companies in the state of Minnesota to conduct an engineering study to evaluate the impacts of raising Renewable Energy Standard (RES) to 40% by the year 2030 and to higher proportions thereafter. This Minnesota Renewable Energy Integration and Transmission Study reviewed the impacts on reliability and costs, including necessary transmission network upgrades, of increasing the RES while maintaining system reliability. As part of this study, Excel Engineering, Inc. was asked to help by performing a Transmission System Conceptual Plan Study. This portion of the study was designed to use powerflow analysis to evaluate certain transmission configurations alongside the production modeling.

4.1 Study Assumptions and Methodology

4.1.1 Study Procedure

The Siemens Power Technologies, Inc. "PSS/E" digital computer powerflow simulation program was used for the steady state thermal analysis to identify the limiting facilities (lines or transformers) which were encountered as the power injection (generation output) was added at the sites of interest per the MRITS Wind-Solar Siting. Beyond the initial load scale-up to configure the models to 2028, the analysis described in this report is based on the "generation to generation" method of modeling new generation resources; consistent with MISO evaluation practice; beyond the initial load scale-up to configure the models to 2028. The "generation to generation" method involves adding new generation and simultaneously backing down or turning off an equal amount of existing generation to keep the system balanced where generation equals load (plus system losses).

A conceptual transmission plan was developed with respect to the Baseline and each scenario. System reliability was determined by technical analyses performed under traditional transmission planning methods, criteria, and assumptions. Performance characteristics to be addressed include the steady-state performance of the following:

Contingency Analysis (powerflow)

- System Intact
- N-1
- Common Structures / Breaker failure (NERC TPL Category C2 & C5)

The local balancing authority areas indicated below were monitored and evaluated for contingency analysis.

Greater than 300 kV

- Wisconsin Electric Power
- ITC Midwest
- MidAmerican Energy Company
- Montana Dakota Utilities
- American Transmission Company

Greater than 200 kV

- Southern Manitoba Area:
  - Facilities South of Winnipeg / Brandon to US border

Greater than 100 kV

- Xcel Energy
- Minnesota Power
- Southern Minnesota Municipal Power Agency
- Great River Energy
- Otter Tail Power
- Western Area Power Administration
- Dairyland Power Cooperative
- ITC Midwest (facilities in Minnesota)
  - Northern Iowa Area: Facilities North of Sioux City / Fort Dodge / Iowa Falls / Waterloo / Dubuque into Minnesota

4.1.2 Models Employed

The study base models used were the 2023 Summer Off-peak (70% load) case and 2023 Summer Peak case from the 2013 MTEP series of models. These models represent the transmission system as it is presently anticipated to be configured in the year 2023. The models were then modified to create a 2028 Baseline model representation with the following additions:

All CapX2020 Group 1 Projects[1]

- Monticello-Quarry-Alexandria-Bison (Fargo) 345 kV line
- Brookings Co-Lyon Co-Cedar Mountain-Helena-Chub Lake (Lake Marion)-Hampton Corner 345 kV, Lyon Co-Hazel Creek 345 kV
- Hampton Corner-North Rochester-North La Crosse 345 kV line
- Wilton-Cass Lake-Boswell 230 kV line

All MISO Multi Value Projects (MVPs) approved in 2011

- Big Stone South-Brookings 345 kV line
- Brookings Co-Lyon Co-Cedar Mountain-Helena-Chubb Lake (Lake Marion)-Hampton Corner 345 kV, Lyon Co-Hazel Creek 345 kV (same as shown in CapX2020 Group 1 Projects)
- Lakefield Jct.-Huntley-Ledyard-Kossuth-O'Brien & Kossuth-Webster 345 kV lines
- Ledyard-Colby-Killdeer-Blackhawk-Hazelton 345 kV line
- Briggs Road-North Madison-Cardinal & Dubuque Co.-Spring Green-Cardinal 345-kV lines
- Ellendale-Big Stone South 345 kV line
- Ottumwa-Adair 345 kV line
- Adair-Maywood-Palmyra 345 kV line
- Palymra-Maywood-Merleman-Meredosia-Ipava & Meredosia-Pawnee 345 kV lines
- Pawnee-Pana-345 kV Line
- Pana-Mt. Zion-Kansas-Sugar Creek 345 kV line
- Reynolds-Burr Oak-Hiple 345 kV

[1] http://www.capx2020.com/, accessed 9/25/2014

- Michigan Thumb Loop Expansion 345 kV line
- Reynolds-Greentown 765 kV line
- Pleasant Prairie-Zion Energy Center 345 kV line
- Fargo-Maple Ridge-Oak Grove 345 kV Line
- Sidney-Rising 345 kV line

Other Transmission Projects

- MTEP Appendix A Projects with In-Service date Prior to 2023
- Manitoba Hydro Bipole III
- Antelope Valley Station-Charlie Creek-Williston-Tioga 345 kV
- Hazleton-Salem 345 kV
- Dorsey-Iron Range 500 kV (Great Northern Transmission Line)
- Increase Square Butte HVDC to 550 MW
- Center - Prairie 345 kV line
- Transmission Owner's transmission changes
    - Winger-Thief River Falls 230 kV line

4.1.2.1 Load Scaling

The load was scaled up in the following areas to get to the 2028 proposed levels.

For Minnesota Utilities

- 0.5% Annually
- 590 MW

For other MISO North and Central Utilities

- 0.75% Annually
- 3460 MW

4.1.2.2 Generation Additions:

The following generation was included: All In-service and/or signed Generator Interconnection Agreements at the start of the analysis.

- Minnesota Power's-Bison Wind 600 MW
- Manitoba Hydro's Keeyask Hydro 695 MW
- Transmission Owner's generation changes

All generation added from the MRITS Wind-Solar Siting were added by the following dispatch criteria of their nameplate value.

Summer Peak Model

- Wind – 20%
- Solar – 60%

Summer Off-Peak Model

- Wind – 90%
- Solar – 60%

The following switched shunt capacitors were added to all models at the following buses for additional voltage support. This was a broad and major addition necessary to build the Baseline model with the load and generation additions to keep the system near 1.0 p.u. voltage, in order to help meet existing MISO North/Central state RPSs.

Switched shunt capacitors were added to all models at the following buses

- 400 MVAR @ Adams 345 kV bus
- 300 MVAR @ Blackhawk 345 kV bus
- 200 MVAR @ Blue Lake 230 kV bus
- 300 MVAR @ Colby 345 kV bus
- 300 MVAR @ Eau Claire 345 kV bus

4.1.3 Baseline Model

The following amounts of generation were added to the MTEP13 2023 models to obtain a Baseline model which meets the current MN RES and other MISO state RPSs.

4.1.3.1 MRITS Wind-Solar Siting

Added beyond MTEP13 2023 models

- Total wind – 6900 MW
- Total Solar – 1509 MW
  - MN Utility PV – 361 MW
  - MN Distributed PV – 96 MW
  - Non-MN Utility PV – 1052 MW
  - Non-MN Distributed PV – 0 MW

Incremental Total – 8409 MW

4.1.4 S1 Model (Added beyond Baseline)

The following amounts of generation were added to the Baseline models to obtain an S1 model which would meet a 40% MN RES standard and existing RPSs in other MISO North/Central states.

4.1.4.1 MRITS Wind-Solar Siting

- Total wind – 1931 MW
  - MN Wind – 1931 MW
  - Non-MN Wind – 0 MW
- Total Solar – 933 MW
  - MN Utility PV – 723 MW
  - MN Distributed PV – 191 MW
  - Non-MN Utility PV – 0 MW
  - Non-MN Distributed PV – 19 MW

Incremental Total – 2864 MW

4.1.5 S2 Model (Added beyond S1)

The following amounts of generation were added to the S1 models to obtain an S2 model which would meet a 50% MN RES standard and a 10% RPS increase in other MISO states.

4.1.5.1 MRITS Wind-Solar Siting

• Total wind – 13636 MW
  • MN Wind – 610 MW
  • Non-MN Wind – 13026 MW
• Total Solar – 6201 MW
  • MN Utility PV – 3840 MW
  • MN Distributed PV – 717 MW
  • Non-MN Utility PV – 3932 MW
  • Non-MN Distributed PV – 154 MW

Incremental Total – 19837 MW

4.2 Results

4.2.1 SCED /MISO Footprint

4.2.1.1 Generation Dispatch Methodology

The models were built while incorporating the wind generation and solar generation within the MISO North and Central footprint. Some wind generation was added using the Security Constrained Economic Dispatch (SCED) which is similar to what is done when MISO creates a base MTEP model and this allows for generation re-dispatch for mitigating overloads. The SCED method determines how the generation resources participating in the market would be dispatched based on economics and reliability where the most cost effective resources are dispatched while maintaining system reliability. This effectively allowed the low-cost wind generation to remain on the system, while other more expensive generation sources are turned down when needed to alleviate congestion. The remainder of the new generation added in the Baseline, S1 and S2 was dispatched in a manner consistent with the MISO Generation Interconnection studies and designated "Footprint Dispatch" and is described as, essentially scaling the whole footprint up and down to keep the swing bus within a certain range after the project under study was added. It is assumed that the swing bus is set based on where it started in the pre-project case.

One of the purposes of the Multi-Value Project (MVP) portfolio was to provide delivery of wind resources needed to meet the MISO state Renewable Portfolio Standards (RPSs). Thus it was decided that for the Baseline case, the 6900 MW (3000+900+3000), deemed the "Multi Value Project wind" and which was required to meet the existing MN RES and other MISO state RPSs, would be dispatched in a SCED methodology and will utilize the MVPs for delivery into the MISO market. Once the Baseline model had been established by using SCED to alleviate constraints, the MISO footprint dispatch methodology was used to offset renewable generation additions in the S1 and S2 scenarios.

4.2.1.2 Baseline

The Baseline models were built incorporating the wind generation of 6900 MW dispatched by Security Constrained Economic Dispatch (SCED) methodology and the solar generation of 1509 MW dispatched across the MISO North and Central footprint. This process first involved adding the 6900 MW of RGOS wind in 20% and 90% (of nameplate) dispatch amounts to the 2028 Summer Peak and Summer Off Peak models respectively and then having MISO run the SCED on these models. Wind plants were modeled at a ±0.95 power factor at the point of interconnection to the transmission system.

MISO performed the SCED on the models and provided the generation changes for the insertion of 6900 MW of Baseline wind generation. These SCED models were then adjusted by adding750 MW of new hydro in Manitoba and then dispatching it to WPS (367 MW) and MP (383 MW) along with the 1509 MW of Solar using the "Footprint Dispatch" method which yields the Baseline model. Note: the 367 & 383 MW of hydro add up to 750 MW and are contractual amounts associated with the Great Northern Dorsey to Iron Range 500 kV project.

The following two Baseline models then were created.

S70 -	Summer Off-Peak (70%) Baseline	MRITS2028-S70-R17-Basea.sav
SUM -	Summer Peak Baseline	MRITS2028-SUM-R17-Basea.sav

Figure 4-1 shows how the bus angles for the Off-Peak condition in the Upper Midwest after generation was added from the original 2013 MTEP 2023 model to the Baseline. In examining the bus angle figure, the larger the phase angle difference between points indicates higher power transfers, lower stability margins and more operational issues such as closing in lines after outages, etc.

A very limited number of facilities were overloaded in the Baseline Scenario, so it was determined to be a good starting point for the study. See the Appendix for the full listing (available upon request from GRE).

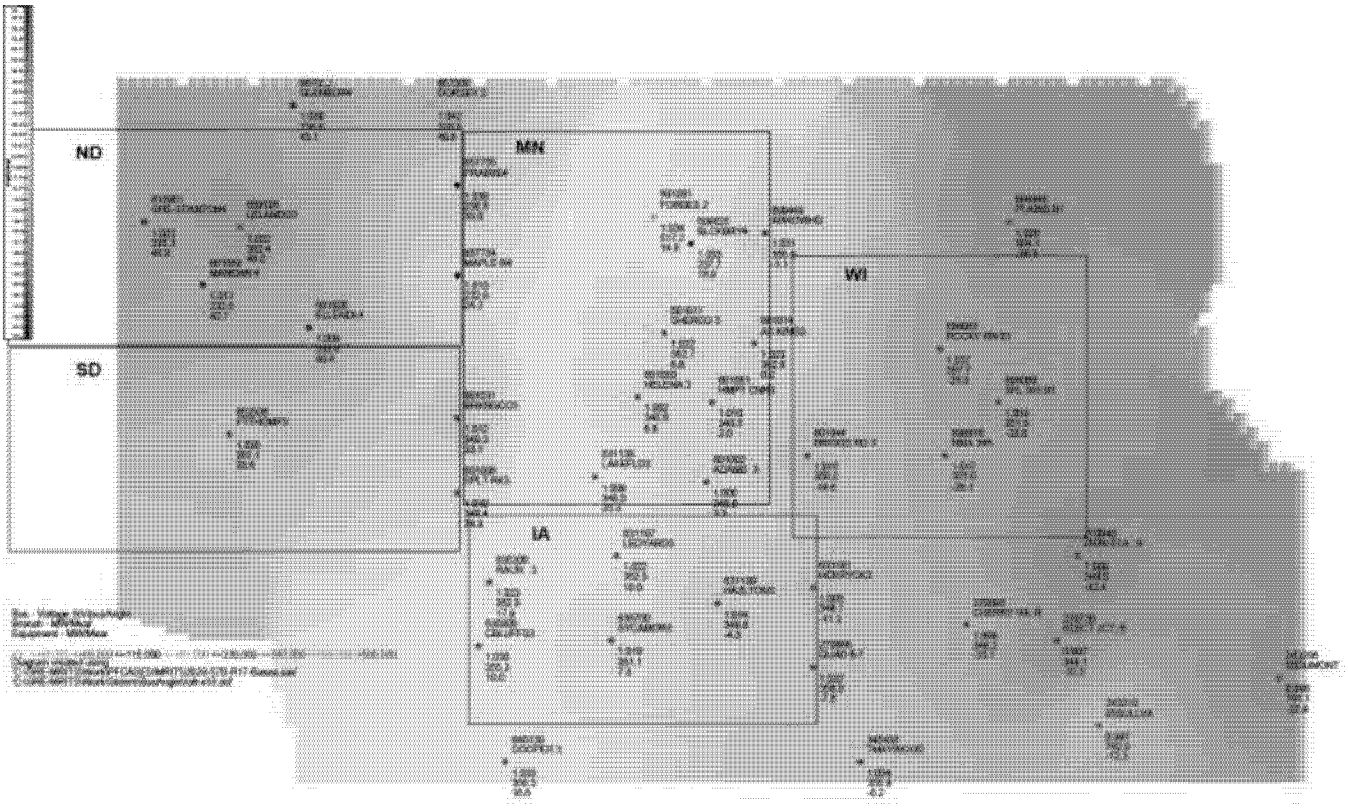

Figure 4-1 Bus Angles from MRITS2028-S70-R17-Basea SCED Model

4.2.1.3 Scenario S1

Similar to some of the generation in Baseline, all of Scenario S1 generation was dispatched to the MISO footprint and the following models were created for S1 Scenario.

S70 -	Summer Off-Peak (70%) S1	MRITS2028-S70-R20-S1.sav
SUM -	Summer Peak S1	MRITS2028-SUM-R20-S1.sav

Figure 4-2 shows how the bus angles change during the Off-Peak condition in the Upper Midwest as the generation was added from Baseline to S1.

As shown in the Bus Angle figure, a bus angle change when moving from Northwest to Southeast is a little more extreme than in the Baseline model.

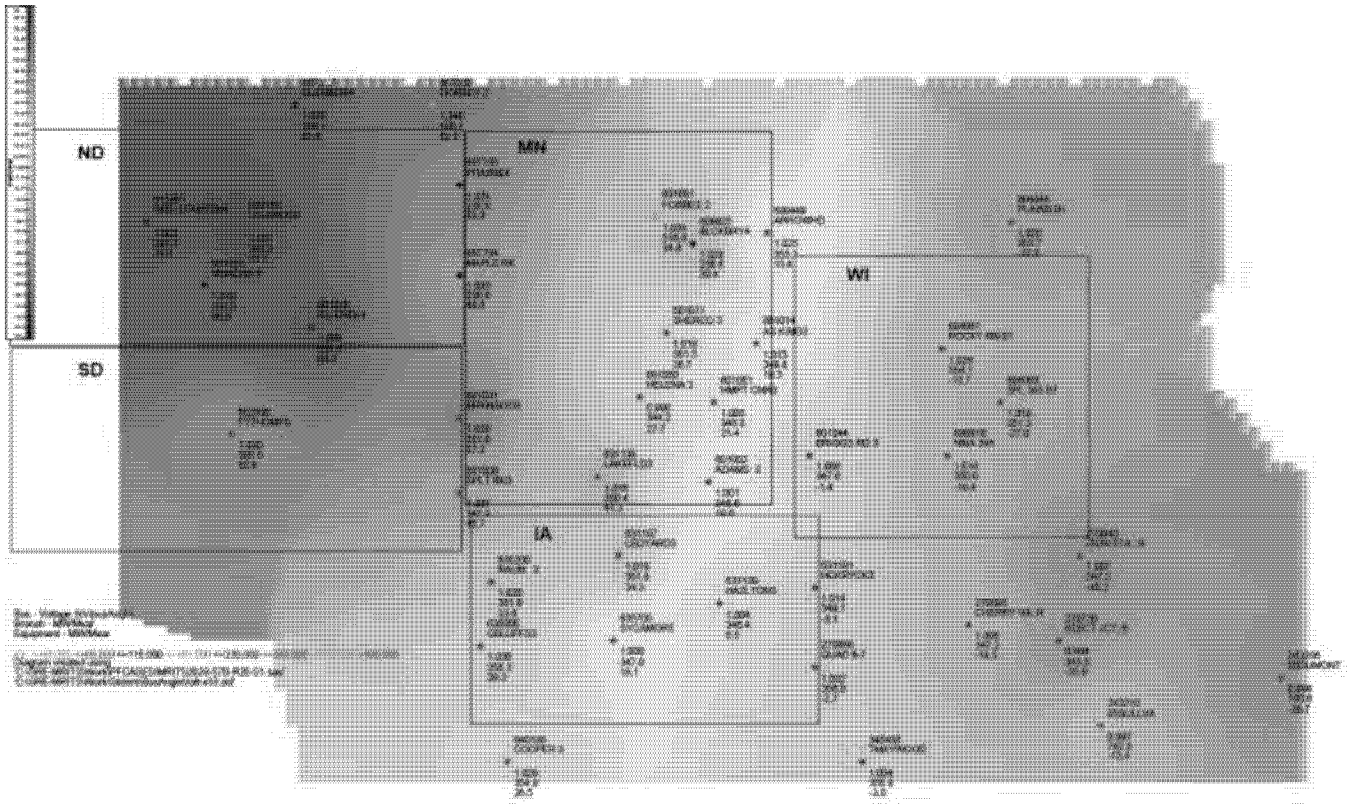

Figure 4-2 Bus Angles from MRITS2028-S70-R20-S1 Model0

Table 4-1 lists mitigation for identified overloads which were required for the S1 Scenario. See Appendices B4 and B6 for the full listing. All costs associated in this report are based on 2014 planning level cost estimates with a ±30 % margin of error.

Table 4-1 S1 Transmission Mitigation

Branch	Possible Mitigation	COST ($M)
Brookings Co-White 345 kV line	WAPA terminal equipment- 1800 MVA	0.50
Cedarsauk-Edgewater 345 kV line	ATC uprate- 750 MVA	1.00
Helena-Scott Co. 345 kV line	XEL rebuild as double circuit	30.00
Ottumwa-Montezuma 345 kV line	ITC uprate- 956 MVA	1.00
Split Rock-White 345 kV line	WAPA terminal equipment- 1195 MVA	1.00
Riverton-Mud Lake 230 kV line	GRE uprate- 383MVA	9.00
98L Tap-Hilltop 230 kV line	MP rebuild - 400 MVA	11.20
Panther-Mcleod 230 kV line	XEL uprate- 391	0.20
Willmar-Granite Falls 230 kV line	GRE rebuild 391MVA	50.00
Hankinson-Wahpeton 230 kV line	OTP uprate- 361 MVA	0.30
Briggs Road-Mayfair 161 kV line	XEL rebuild- 400 MVA	10.00
Drager-Grand Junction 161 kV line	CBPC rebuild- 326 MVA	37.50
Boone Jct-Fort Dodge 161 kV line	MEC / CIPCO rebuild- 326 MVA	62.50
Hazleton-Dundee 161 kV line	ITC terminal equipment- 326 MVA	0.20
Liberty-Dundee 161 kV line	ITC rebuild- 326 MVA	6.50
Wabaco-Rochester 161 kV line	DPC rebuild - 400 MVA	10.90
43L Tap-Laskin 138 kV line	MP rebuild - 200 MVA	3.00
Wilmarth-Swan Lake 115 kV line	XEL terminal equipment- 144 MVA	0.20
Wilmarth-Eastwood 115 kV line	XEL uprate- 310 MVA	3.00
Souris-Velva Tap 115 kV line	XEL terminal equipment- 144 MVA	0.20
Monticello-Oakwood 115 kV line	XEL rebuild- 310 MVA	12.00
Black Dog-Wilson 115 kV line	XEL terminal equipment- 310 MVA	0.20
Chisago-Lindstrom 115 kV line	XEL upgrade- 400 MVA	0.50
Scott Tap-Scott Co. 115 kV line	XEL Rebuild- 310 MVA	2.00
Hassan-Oakwood 115 kV line	XL rebuild- 310 MVA	7.00
Velva Tap-McHenry 115 kV line	XEL terminal equipment- 144 MVA	0.20
Hibbard-Winter St 115 kV line	MP rebuild - 240 MVA	3.00
Etco-Forbes 115 kV line	MP rebuild - 200 MVA	3.00
Forbes-Iron Tap 115 kV line	MP rebuild - 200 MVA	3.00
Hibbing-44L Tap 115 kV line	MP terminal equipment- 80 MVA	0.20

Branch	Possible Mitigation	COST ($M)
Iron Tap-Tbird 115 kV line	MP rebuild - 200 MVA	3.00
Tbird-37L Tap 115 kV line	MP rebuild - 200 MVA	3.00
Blackberry-Panasa Naswak 115kV	MP upgrade- 240 MVA	2.16
Rugby OTP-Rugby CPC 115 kV line	OTP rebuild - 200 MVA	1.00
Halliday-Beulah 115 kV line	WAPA terminal equipment- 144 MVA	0.20
Rugby-Rugby CPC 115 kV line	BEPC rebuild - 200 MVA	1.00
Johnson Jct-Morris 115 kV line	GRE terminal equipment- 99 MVA	0.20
Johnson Jct-Ortonville 115 kV line	OTP/MRES rebuild - 200 MVA	16.00
Fort Randall-Spencer 115 kV line	WAPA terminal equipment 144 MVA	0.20
Blaisdell-Palermo 115 kV line	BEPC rebuild - 200 MVA	8.00
Logan-SW Minot 115 kV line	BEPC rebuild - 200 MVA	7.00
Hazel Creek 345/230 kV Tx #6	XEL add 2nd 336 MVA transformer	6.00
Stone Lake 345/161 kV Tx #9	XEL replace with 448 MVA transformer	7.50
Eau Claire 345/161 kV Tx #9 & 10	XEL replace BOTH with 448 MVA transformers	15.00
Lyon Co 345/115 kV Tx #1	XEL add 2nd 448 MVA transformer	7.50
McHenry 230/115 kV Tx #1	GRE replace with 187 MVA transformer	2.00
LaCrosse 161/69 kV Tx #1 & 2	XEL replace BOTH with 112 MVA transformers	3.20
Marshland 161/69 kV Tx #1 & 2	XEL replace BOTH with 112 MVA transformers	3.20
Gravel Isle 161/69 kV Tx #5 & 6	XEL replace BOTH with 112 MVA transformers	3.20
West Faribault 115/69 kV Tx #1 & 2	XEL replace BOTH with 140 MVA transformers	3.60
Paynesville 115/69 kV Tx #1 & 2	XEL replace with 70 MVA transformer	2.80
Prentice 115/69 kV Tx #5	XEL replace with 70 MVA transformer	1.40
Holcombe 115/69 kV Tx #1	DPC replace with 70 MVA transformer	1.40
Glendale 115/69 kV Tx #1 & 2	GRE replace Both with 112 MVA BOTH transformers	3.20
	Add breakers at Arrowhead 115kV bus*	2.00
	Total Cost	**373.06**

* To mitigate the contingencies that remove the full 115 kV bus sections, install a breaker-and-half scheme

The map in Figure 4-3 shows all the mitigation required to fix the transmission concerns for dispatching S1 generation to the MISO Footprint. The mitigations are spread throughout the study region.

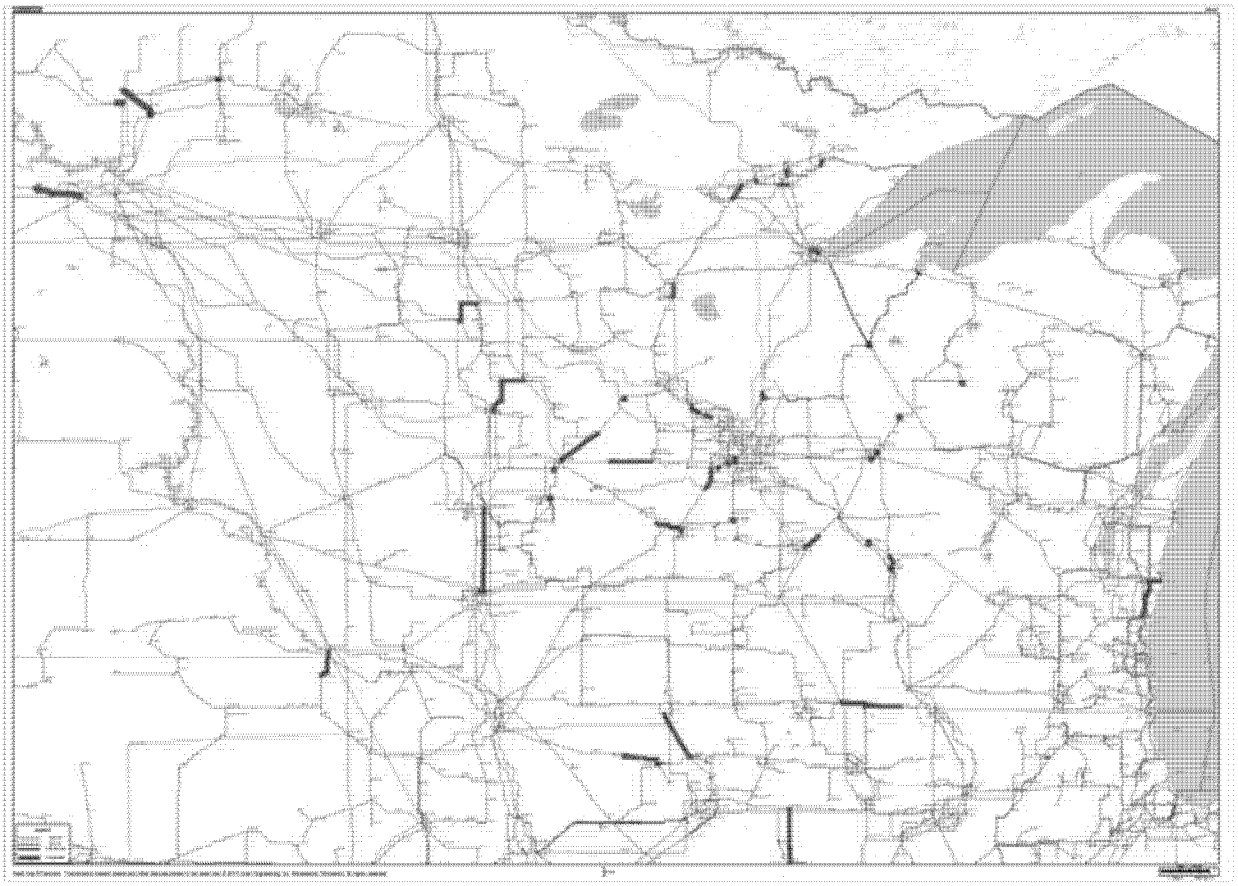

Figure 4-3 S1 Transmission Mitigation Map

The S1 powerflow cases were repeated to verify transmission upgrade results and ensure that the mitigations didn't cause subsequent cascading issue on the system. These mitigations are considered conceptual at this point and thus have not been optimized where, for example, one upgrade or a new facility may alleviate one or more of the identified overloads. Thus, further study would be required for the identification of the most practicable upgrade to alleviate these violations. These 54 mitigations could create a challenge in scheduling and coordinating outages for the construction time necessary to upgrade the facilities.

4.2.1.4 S2 Scenario

The S2 Scenario generation could not be added or dispatched to the MISO footprint similar to Scenario 1 without making some changes and/or additions to the Scenario 1 models primary due to the large amount of renewable generation (17245 MW) being added to the model. The generation addition created an extensive number of violations during system intact conditions along with some extreme contingencies that were difficult to solve.

Figure 4-4 shows an extreme difference in how the bus angles change during the Off-Peak condition in the Upper Midwest as the generation is added from S1 to S2.

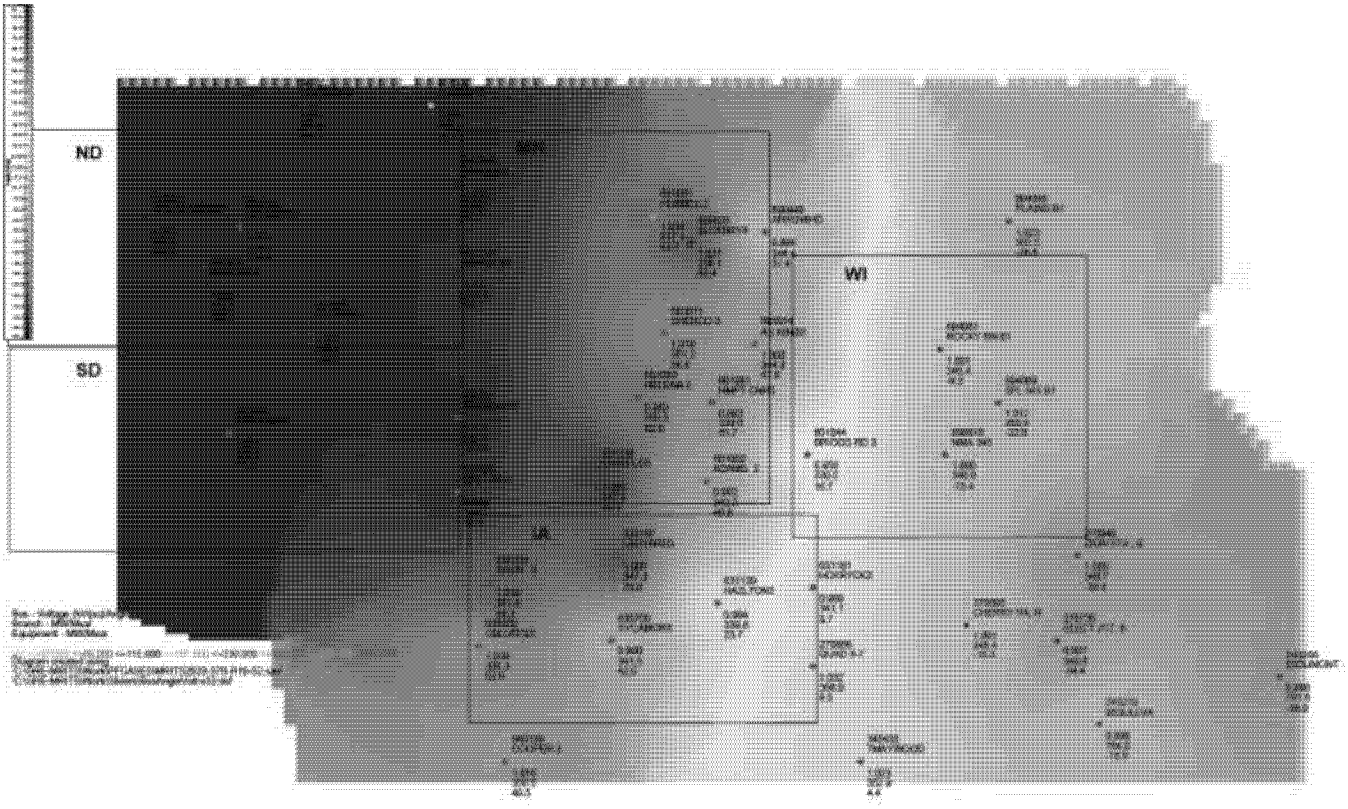

Figure 4-4 Bus Angles from MRITS2028-S70-R19-S2 Model

4.2.2 Scenario 2

4.2.2.1 Transmission Expansion

In order to get the additional S2 17,245 MW of generation necessary to increase the MN RES to 50% and MISO states collectively to 25% into the case, the transmission expansion projects shown in were included. These expansions are also shown on the map in Figure 4-5.

Figure 4-6 shows how the bus angles change during the Off-Peak condition in the Upper Midwest when added the S2 Transmission Expansion. The change occurs mostly in the area east and southeast of Minnesota.

The cases used with these changes were:

S70 -	Summer Off-Peak (70%) S2	MRITS2028-S70-R19-S2-Trans.sav
SUM -	Summer Peak S2	MRITS2028-SUM-R19-S2-Trans.sav

Table 4-2 S2 Transmission Expansion

Branch	COST ($M)
Corridor Project (rebuilding existing 230 kV line to 345 kV) Hazel Creek-Panther-Mcleod-Blue Lake double circuit 345 kV line	466.00
Iron Range-Arrowhead 345 kV line	182.00
Sheldon-Eau Claire-Alma-Adams-Killdeer 345 kV line	700.00
Blackhawk-Montezuma 345 kV line	196.00
Big Stone South-Hazel Creek 345 kV line	200.00
Bison-Alexandria-Quarry-Monticello 345 kV line #2(dbl circuit CapX2020)	204.10
Brookings Co-Lyon Co 345 kV line #2(dbl circuit CapX2020)	58.00
Helena-Chub Lake-Hampton 345 kV line #2(dbl circuit CapX2020)	47.00
Hampton-North Rochester-Alma 345 kV line #2(dbl circuit CapX2020)	75.00
Total Cost	**$2,128.10**

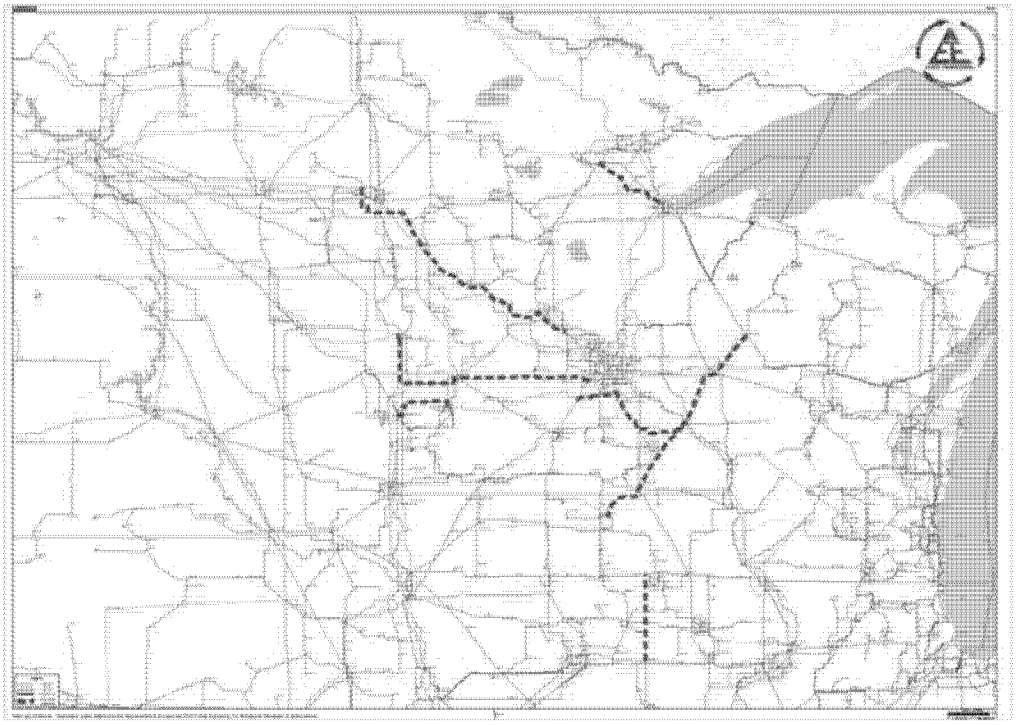

Figure 4-5 S2 Transmission Expansion Map

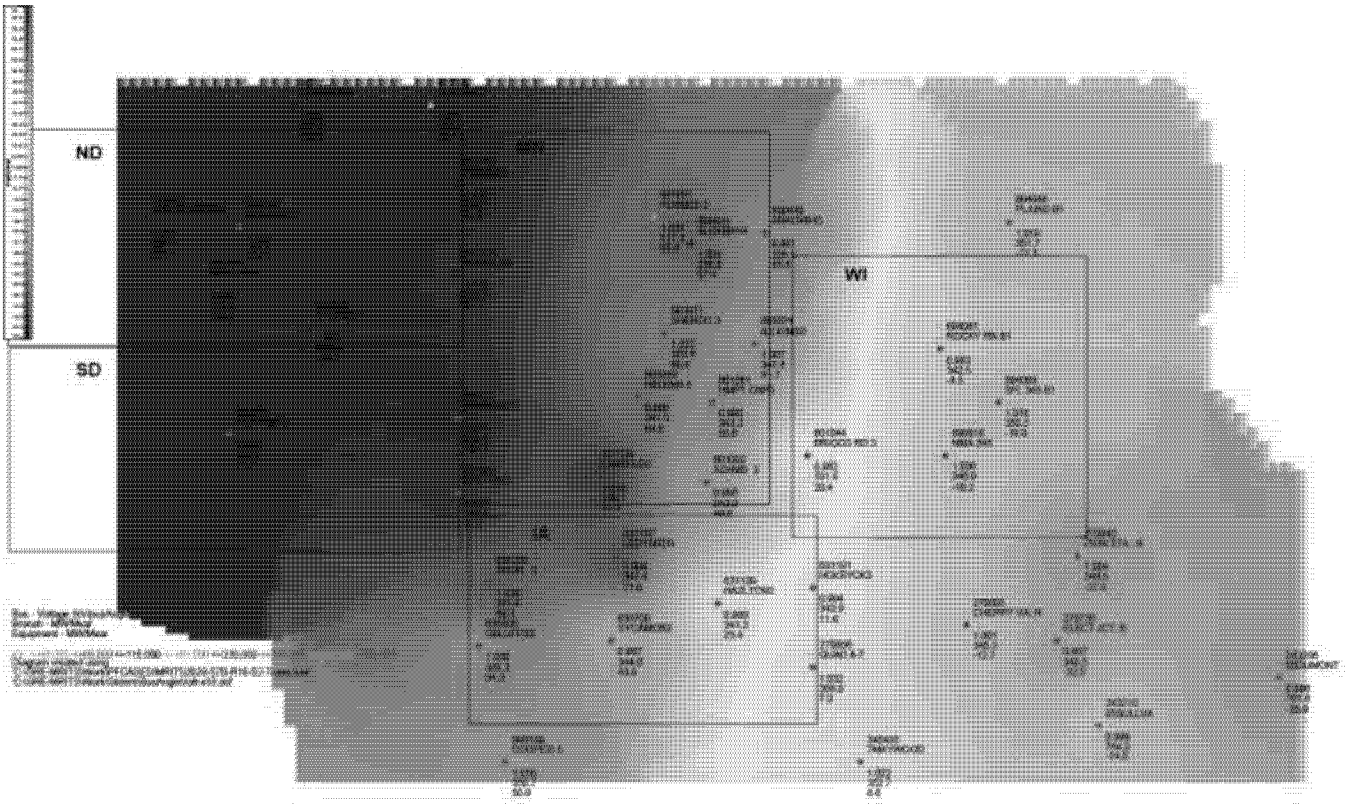

Figure 4-6 Bus Angles from MRITS2028-S70-R19-S2-Trans Model

4.2.2.2 SCED and Top 4 to Bottom 10

Even after the transmission expansion was added to the models, there were still concerns with the amount of equipment overload violations in the model along with some outages not allowing the model to solve. The MRITS task force decided to perform SCED on the S2 cases with the S1 mitigation and the S2 transmission expansion. MISO performed the SCED on models. The cases used for the S2 results were:

S70 -	Summer Off-Peak (70%) S2	MRITS2028-S70-R19-S2-Trans-R2-SCED-A.sav
SUM -	Summer Peak S2	MRITS2028-SUM-R19-S2-Trans-R2-SCED-A.sav

Based on the Production Cost Modeling results, it was noted that several of the wind generation sites from the MRITS Wind-Solar Siting were causing overloads in the thermal case were also congested and thus restricted in the production modeling. The MRITS TRC decided that the top 4 congested non-Minnesota centric generation sites would have generation reduced and moved to the bottom 10 least congested non-Minnesota centric generation sites (T4B10) (as described in the Siting Section). The resulting new S2 cases were:

S70 -	Summer Off-Peak (70%) S2	MRITS2028-S70-R19-S2-Trans-R2-SCED-A-T4B10.sav
SUM -	Summer Peak S2	MRITS2028-SUM-R19-S2-Trans-R2-SCED-A-T4B10.sav

Figure 4-7 shows how the bus angles change during the Off-Peak condition in the Upper Midwest when the S2 Transmission Expansion is added with SCED of S2 generation and the Top4-Bottom10.

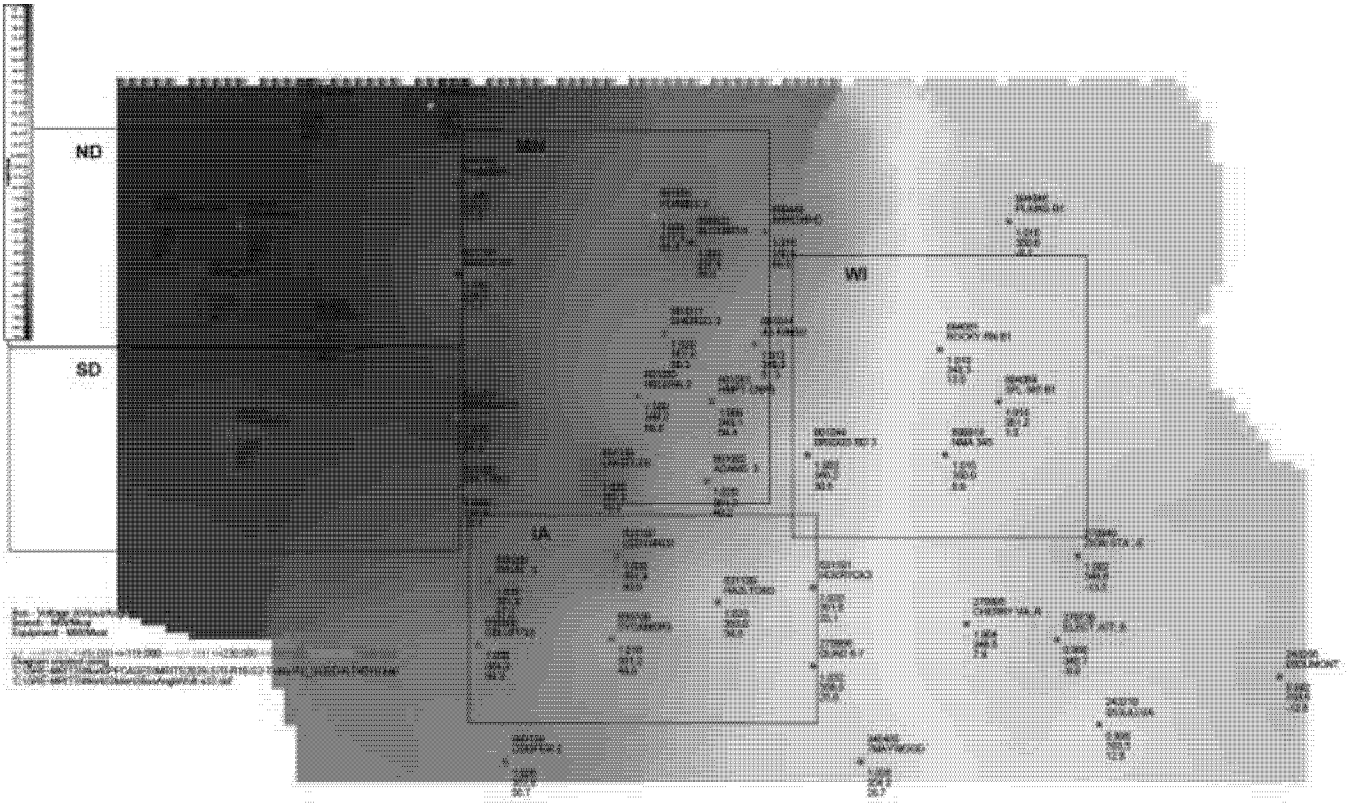

Figure 4-7 Bus Angles from MRITS2028-S70-R19-S2-Trans-R2-SCED-A-T4B10 Model

In addition to the S2 Transmission Expansions ($2.128B from) and moving some wind generation from the top 4 congested sites to the bottom 10 least congested non-Minnesota centric generation sites, steady state thermal analysis results identified transmission mitigation for the S2. The S2 additional mitigations are shown in Table 4-3. The locations are shown in Figure 4-8. See the Appendix for the full listing (available upon request from GRE).

Table 4-3 S2 Transmission Mitigation

Branch	Possible Mitigation	COST ($M)
Gardner Park-Sheldon 345 kV line	ATC uprate to 1219 MVA	10.00
Sioux City-Twin Church 230 kV line	NPPD rebuild 390 MVA	37.76
McHenry-Coal Creek Tap 230 kV line	GRE rebuild 450 MVA	78.08
Lakefield-Dickenson Co. 161 kV line	ITC Rebuild 400 MVA	26.75
Triboji-Dickenson Co. 161 kV line	ITC Rebuild 400 MVA	3.00
Huntley-Freeborn 161 kV line	ITC Rebuild 400 MVA	47.88
Webster-Wright 161 kV line	MEC Rebuild 400 MVA	14.75
Alma-Lufkin 161 kV line	DPC Rebuild - 400 MVA	31.50
La Crosse-Mayfair 161 kV line	XEL Rebuild 400 MVA	4.63
Devils Lake-Ramsey 115 kV line	GRE Uprate 120 MVA	0.50
Velva Tap-GRE McHenry 115 kV line	XEL Rebuild310 MVA	5.20
Souris-Velva Tap 115 kV line	XEL Rebuild310 MVA	19.60
Sheldon Pump-Osprey 115 kV line	XEL Rebuild310 MVA	20.90
Osprey-Hawkin 115 kV line	XEL Rebuild 310 MVA	14.00
Hutch McLeod-Hutchinson 3M 115 kV line	GRE Rebuild 310 MVA	5.20
Hutch Muni-Hutchinson 3M 115 kV line	GRE Rebuild 310 MVA	1.10
Sioux City 345/230 kV Tx 1	WAPA replace with a 2x336 MVA transformer	12.00
Stone Lake 345/161 kV Tx 9	XEL modified S1 mitigation, but adding a 2nd 336 MVA transformer rather than replacing	-
GRE McHenry 230/115 kV Tx #1	GRE replace with 224 MVA transformer	4.00
GRE Spring Creek 161/69 kV Tx #2	GRE replace BOTH with 112 MVA transformers	3.20
Prairie 115/69 kV Tx #2	MPC add 69 kV breakers	2.00
GRE St. Boni 115/69 kV Tx #1	GRE replace with 112 MVA transformer	1.60
Split Rock 345/115 kV Tx # 11	XEL add 3rd 448 MVA transformer	7.50
	Total Cost	**351.14**

As seen in Figure 4-8, the mitigations are spread throughout the study region and there is a recognition that there may have been more system overloads outside the study monitor area.

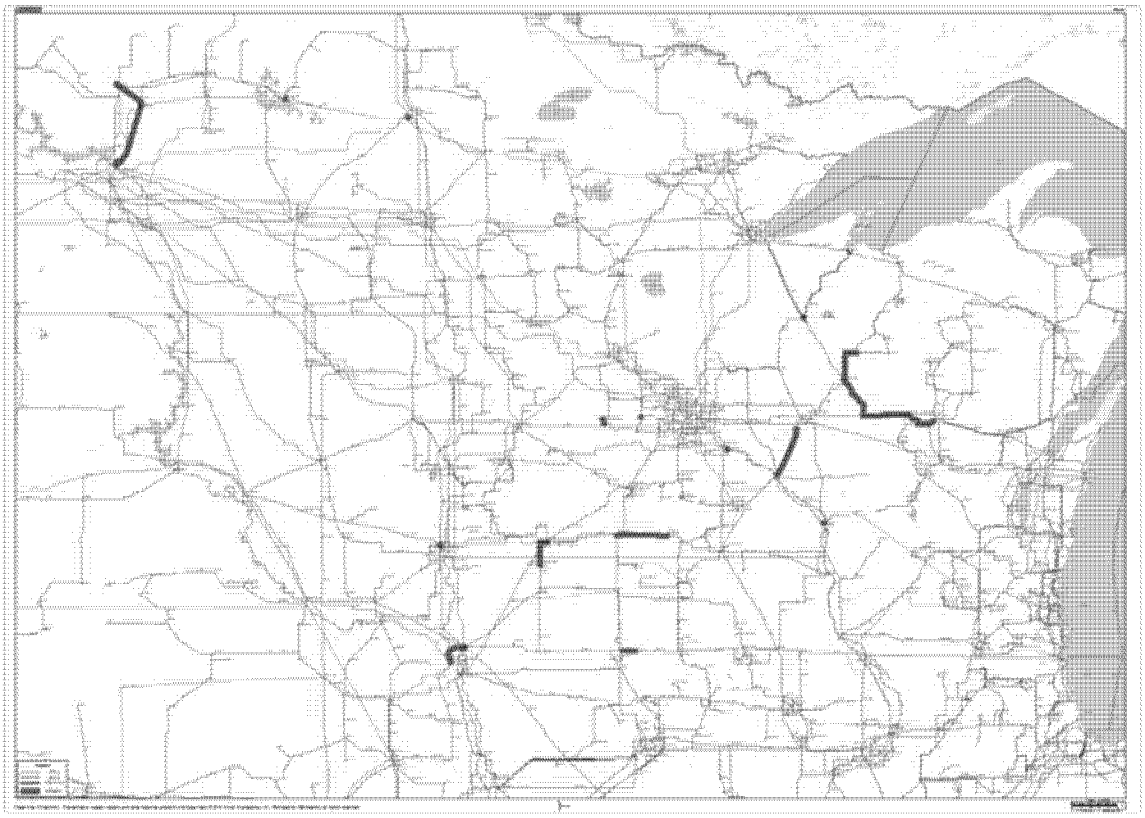

Figure 4-8 Transmission Mitigation Map

The S2 powerflow cases were repeated to verify transmission upgrade results. The transmission expansions and mitigations are considered high-level and conceptual at this point and thus have not been intensively analyzed and compared with other alternative mitigations nor have the projects been optimized where, for example, one upgrade or a new facility may alleviate one or more of the identified overloads.

Thus, further study would be required for the identification of the most practicable expansion or upgrade to alleviate these specific violations or widespread grid issues. These upgrades would require coordination with study and validation by MISO and other utilities. These 9 expansions and 23 mitigations could create a challenge in scheduling and coordinating outages for the construction time necessary to upgrade and build the facilities.

4.2.2.3 Production Cost Mitigation

Following the steady state power flow modeling which produced the transmission expansions and mitigations, Production Cost Modeling was performed to determine if any additional transmission facilities should be upgrades to help alleviate market congestion. This generation siting shift assisted in producing a more reliable and efficient market system. Table 4-4 lists mitigations from the production cost analysis. See the Appendix for the full listing (available upon request from GRE).

Table 4-4 S2 Transmission Mitigations from Production Cost Analysis

Branch	Possible Mitigation	COST ($M)
Blackhawk SW Yd-Colley Rd 138 kV line	ATC Rebuild- 400 MVA	1.95
Adams 161/69 kV Tx #1 112MVA	ITC replace with 112 MVA transformer	1.60
Huntley (Winnebago) 161/69 kV Tx #1 70 MVA	ITC replace with 70 MVA transformer	1.40
NW Beloit-Paddock 138 kV line	ATC Rebuild- 400 MVA	3.15
Hankinson-Wahpeton 230 kV line	OTP Rebuild- 430 MVA	40.80
Wapello Co.-Jeff 161 kV line	ITC Rebuild- 400 MVA	33.90
Blue Earth Tap-Huntley (Winnebago) 161 kV line	ITC Rebuild- 400 MVA	5.25
	Total Cost	**88.05**

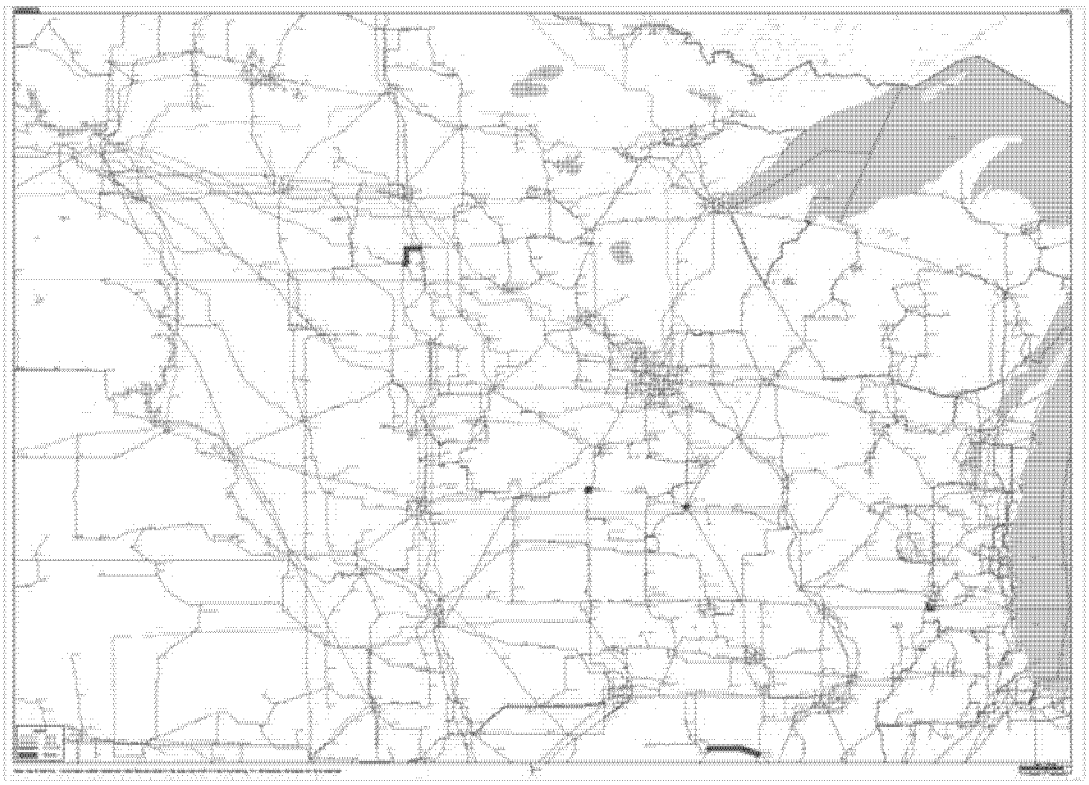

Figure 4-9 Map of S2 Transmission Mitigations from Production Cost Analysis

4.2.2.4 HVDC Transmission

Given the large number and magnitude of 345 kV mitigations identified for Scenario 2, it was decided to conduct a mitigation sensitivity using a HVDC design to deliver the non-MN MISO wind located in western MISO to eastern MISO. This HVDC multi-terminal line design was guided by Bus Angles shown in Figure 4-4 in order to connect the HVDC terminals to the extreme angle differences (Red and Blue). The HVDC line was approximately 800 miles long and operated at 600 kVdc with two converter buses located at Brookings County and O'Brien County and two invertor buses located Breed (Sullivan) and Dumont.

All runs were done only on the off-peak (S70) case and were not optimized in any form, but to be used as a reference. The line was tested at 2000, 2500, 3000 and 3500 MW. The cases used in the review were:

2000 MW	MRITS2028-S70-R19-S2-HVDC-2000.sav
2500 MW	MRITS2028-S70-R19-S2-HVDC-2500.sav
3000 MW	MRITS2028-S70-R19-S2-HVDC-3000.sav
3500 MW	MRITS2028-S70-R19-S2-HVDC-3500.sav

Figure 4-10 is a map showing the HVDC line location and the four terminals (red dots).

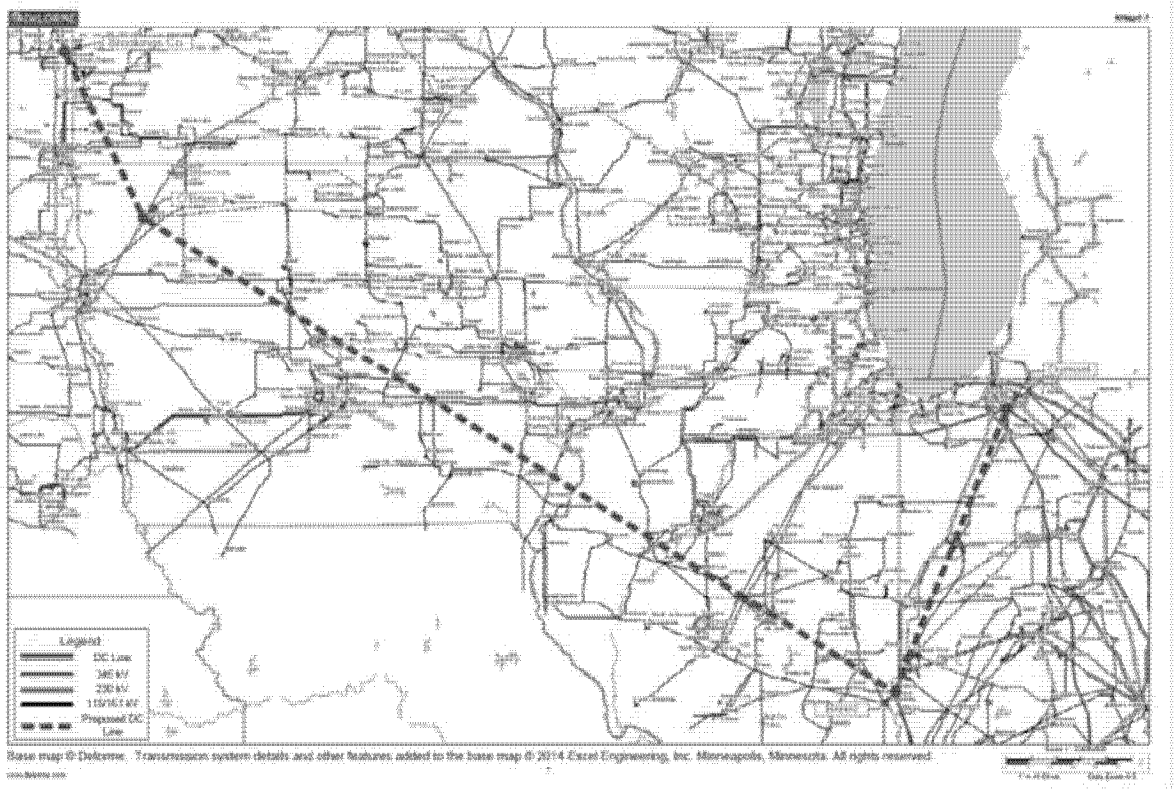

Figure 4-10 HVDC Transmission Map

The HVDC line transferred a significant amount of power from the converter terminals in the west, where a major amount of the MRITS Wind-Solar Siting were located at or near those terminals. If future wind would be developed further away from the HVDC terminals, the HVDC Transmission Expansion option would not be as efficient at transferring power from Western MISO to Eastern MISO and other transmission upgrades would likely be needed to get the new wind to the HVDC terminals. Contingency or Outage of the HVDC line as full, two-pole, or partial, single pole was not evaluated during this study. These outages would require an extensive study and thus was not conducted. We do know from previous work in this study that the ac transmission system could not accommodate all the S2 generation without some additional transmission, so some level of generation runback/tripping or ac transmission expansion would be required in the case of a single or double pole HVDC outage. The estimated cost for a four terminal 3500 MW HVDC for this distance would be approximately $3 Billion. See the Appendix for the full listing (available from GRE upon request).

An undetermined portion of the HVDC estimated cost could be allocated to central and eastern portions of MISO to help meet their respective RPSs.

Table 4-5 lists the ac transmission mitigation required beyond S1 mitigation and the HVDC at 3500 MW. This is an increase in $280M of mitigation beyond the S1 mitigations. This table does not include mitigations for the outage of the HVDC.

Table 4-5 S2 AC Transmission Mitigations required with HVDC Option

Branch Violation	Contingency	COST ($M)
Hazelton-Mitchell Co. 345 kV line	ITC/ MEC Upgrade- 1464 MVA	201.60
McHenry-Coal Creek Tap 230 kV line	GRE upgrade- 637 MVA	78.08
McHenry-Balta 230 kV line	GRE upgrade- 480 MVA	69.44
Big Stone-Big Stone South 230 kV line	OTP upgrade- 831 MVA	5.00
Oakes-Ellendale 230 kV line	OTP upgrade- 480 MVA	38.40
Blair-Watertown 230 kV line	WAPA upgrade- 480 MVA	46.40
Briggs Road-Mayfair 161 kV line	XEL upgrade- 434 MVA	10.00
Lacrosse-Mayfair 161 kV line	XEL upgrade- 434 MVA	4.63
Wheaton-Elk Mound 161 kV line	XEL upgrade-434 MVA	4.50
Beaver Creek-Adams 161 kV line	DPC upgrade- 434 MVA	18.88
Wabacco-Alma 161 kV line	DPC upgrade- 434 MVA	25.38
Swan Lake-Fort Ridgely 11 kV line 5	XEL upgrade- 232 MVA	13.20
Franklin-Redwood Falls 115 kV line	XEL upgrade- 232 MVA	12.80
MN Valley-Redwood Falls 115 kV line	XEL upgrade- 232 MVA	27.80
Lawrence Creek-Shafter 115 kV line	XEL upgrade- 350 MVA	6.10
Lindstrom-Shafer 115 kV line	XEL upgrade- 319 MVA	2.80
Big Stone-Highway 12 115 kV line	OTP upgrade- 319 MVA	2.00
Highway 12-Ortonville 115 kV line	OTP upgrade- 319 MVA	4.50
Hoot Lake-Fergus Falls 115 kV line	OTP upgrade- 232 MVA	4.20
OTP Forman-WAPA Forman 115 kV line	OTP upgrade- 232 MVA	0.20
Devils Lake SE-Ramsey 115 kV line	OTP upgrade- 232 MVA	0.20
Aberdeen Jct-Ellendale 115 kV line	NWE upgrade- 232 MVA	39.00
Iron Range 500/230 Tx	MP upgrade- 1043 MVA	0.00
Forman 230/115 Tx	WAPA replace w/ 180 MVA transformer	2.00
Big Stone South 345/230 Tx #1 & 2	OTP replace BOTH w/ 800 MVA transformer	15.00
Big Stone South 230/115 Tx	OTP replace with 390 MVA transformer	6.00
	Total Cost	**630.60**

4.3 Conceptual Transmission Conclusions

The model building for the steady state thermal analysis involved significant transmission and generation additions and load increases to reflect the Baseline assumptions of the present MISO state RPSs in a 2028-2030 timeframe along with the planned transmission and generation build-outs.

The generation dispatch involved a combination of methodologies to best represent the future system grid which accommodated the lowest fuel cost generation units and future contracts while maintaining system reliability.

The Scenario 1 Transmission Mitigations, as identified with steady state thermal powerflow analysis, to accommodate an increase wind and solar generation necessary to increase the MN RES to 40% involved 54 facilities with a total estimated cost of $373M.

The Scenario 1 mitigations are considered conceptual at this point and thus have not been optimized and thus further study would be required for the upgrading/mitigation of these violations. These 54 mitigations could create a challenge in scheduling and coordinating outages for the construction time necessary to upgrade the facilities.

To reliably accommodate the addition of 17,245 MW of Scenario 2 generation necessary to increase the MN RES to 50% and MISO states collectively to 25% into the case and alleviate widespread system issues, a significant amount of transmission expansions were identified and included in the S2 models. These expansions involved 9 facilities with a total estimated cost of $2,128M.

Even with the S2 expansions identified above, there were still concerns with the high number of facility overloads and violations, it was noted that several of the wind generation sites from the MRITS Wind-Solar Siting were causing market congestion and it was decided that the top 4 congested non-Minnesota centric generation sites would have generation reduced and moved to the bottom 10 least congested non-Minnesota centric generation sites (T4B10). This generation siting shift assisted in producing a more reliable and efficient market system.

In addition to the S2 Expansions and moving some wind generation from the top 4 congested sites to the bottom 10 least congested non-Minnesota centric generation sites, steady state thermal powerflow analysis still identified Scenario 2 Transmission Mitigations, involving 23 facilities with a total estimated cost of $351M.

The Production Cost Modeling & Analysis showed market congestion caused by the overload of several facilities. These congestion points in the MN Centric area were selected for mitigation and these involved 7 facilities with a total estimated cost of $88M.

The total Scenario 2 expansions and upgrades involved 39 projects at an estimated cost of $2,567M. The cost of the Scenario 1 mitigations should be added to the S2 costs in order to accommodate a MN RES of 50% and a MISO collective RPS of 25%. It should be noted that an undetermined portion the S2 transmission expansions and upgrades are likely due to the non-MN MISO renewables and not exclusively for the MN renewables. No effort was made to separate these costs into those assigned to MN Renewables and those to non-MN MISO renewables.

Table 4-6 Scenario Transmission Cost Breakdown

	Expansion Costs ($M)	Mitigation Costs ($M)	Market Mitigation Costs ($M)	Total Costs ($M)
Scenario 1	$0	$373	$0	**$373**
Scenario 2	$2,128	$351	$88	**$2,567**

An alternative to the above expansions and mitigations, a high level HVDC line was tested as a sensitivity. The modeled 600 kV HVDC line was about 800 miles long and with converter buses located at southeastern South Dakota and northwest Iowa and two inverter buses located northern and southern Indiana. The estimated cost of this HVDC project was approximately $3B and still required 26 mitigations with an estimate cost of approximately $631M for a total HVDC portfolio cost of approximately $3.6B, which is approximately a 40% increase over the ac mitigation portfolio).

The transmission expansions and mitigations are considered high-level and conceptual at this point and thus have not been intensively analyzed nor optimized thus, further study would be required for the identification of the most practicable expansion or upgrade and would likely change as the wind is actually developed. These upgrades would require coordination with MISO and other utilities. These transmission expansions and mitigations could create a challenge in scheduling and coordinating outages for the construction time necessary to upgrade and build the facilities.

This study builds upon several previous state mandated renewable related studies and the analysis and results have demonstrated the regional nature and benefits of the grid and the operating market.

5 DYNAMIC SIMULATION MODEL

This section documents the data source for the dynamic modeling, benchmarking of the model, modifications made to represent the future high-renewable scenarios and criteria for evaluating stability simulations.

5.1 Data Sources and Benchmarking of Dynamic Models

The original data for dynamic analysis provided by the Minnesota utilities was based on an MTEP 2013 data set. The following files were provided:

Powerflow data in PSS/E raw data format: *2023_SH_2013DPP_August_Pre-DPP.raw*

Case comments:

2023 SHOULDER LOAD CASE

AUG 2013 DPP BASE CASE, PRE DPP

Dynamic data in PSS/E dyre data format: 2018_final_2.dyr

Contingency description files provided in PSS/E response file (.idv) format

These files were converted to GE PSLF format and tested by simulating the benchmark contingencies listed in Table 5-1. Simulations were compared to results obtained using a similar database in PSS/E. Simulation results were reviewed with the MRITS Technical Team. After some minor modifications to the dynamic data (adding mechanically switched capacitor models), the benchmarking results were deemed acceptable.

Note that the PSLF model does not include custom HVDC controls. Rather, it represents a typical HVDC system. Simulation results were reviewed by Technical Team members to ensure that the simulated HVDC response represented expected response. In particular, commutation failure and blocking was reviewed for disturbances near the HVDC terminals.

Table 5-1 Benchmark Contingencies

Name	Description
EI2	CU HVDC Permanent Bipole fault with tripping of both Coal Creek units.
AG1	SLG fault with breaker fail at Leland Olds on the Ft. Thompson 345 kV line
AG3	3 phase fault at Leland Olds on Ft. Thompson 345 kV line, Clear both ends of the line in 4 cycles
NAD	4cycles 3 phase fault on the Dorsey to Forbes 500 kV line D602F at Forbes. Runback bi-poles that terminate at Dorsey
PCS	SLG fault t with breaker fail at King with 8P6 stuck. Trips King-EauClaire-Arpin and King-Chisago 345 kV line

5.2 Dynamic Load Model

After obtaining acceptable benchmarking results, the dynamic data set was modified to include a more detailed representation of the study area loads. The objective of adding a dynamic load model was to capture possible fault-induced delayed voltage recovery issues caused by reduced synchronous generation.

The GE PSLF composite load model CMPLDW was added at all loads greater than 5 MW throughout MISO. The topology of the composite load (shown in Figure 5-1) is intended to give more realistic representation of dynamic load behavior than present practice. The model adds distribution transformer and feeder for each load. The load is then modeled at the distribution bus as a composite of different induction motors, electronic load and static load.

In order to develop parameters for the load model, the Minnesota utilities classified all loads in their service territory. Classifications for non-industrial loads are shown in Table 5-2. Classifications for industrial loads are shown in Table 5-3. Loads not identified by the Minnesota utility were assumed to be either power mixed residential/commercial, or power plant auxiliary. Power plant auxiliary loads were assumed if the load was at a generator bus with a rated voltage less than 30 kV.

The load characteristics used for each individual load were based on the load type using the WECC parameters. In total, the CMPLDW model was added to 2045 loads (37.8 GW for the shoulder period). Note that a different set of parameters was used for the light and shoulder load cases and the peak load case. This was intended to represent the higher level of motor load, particularly air conditioning, during the summer peak load than during spring and fall.

The parameters of the four equivalent motors are particularly important for dynamics, as the tendency for motor groups to stall (or not) during major voltage depressions has a substantial impact on system stability. One of the key features of the composite load model includes the ability to control whether stalled motors trip (by contactors opening) or continue to stay attached drawing starting current. Since the motor stalling behavior in the composite load has such a major and acutely non-linear effect on stability results, for this study, all motor tripping in the composite model is disabled. This is very conservative, and it allows for simpler and more illuminating comparison between dynamic simulation cases.

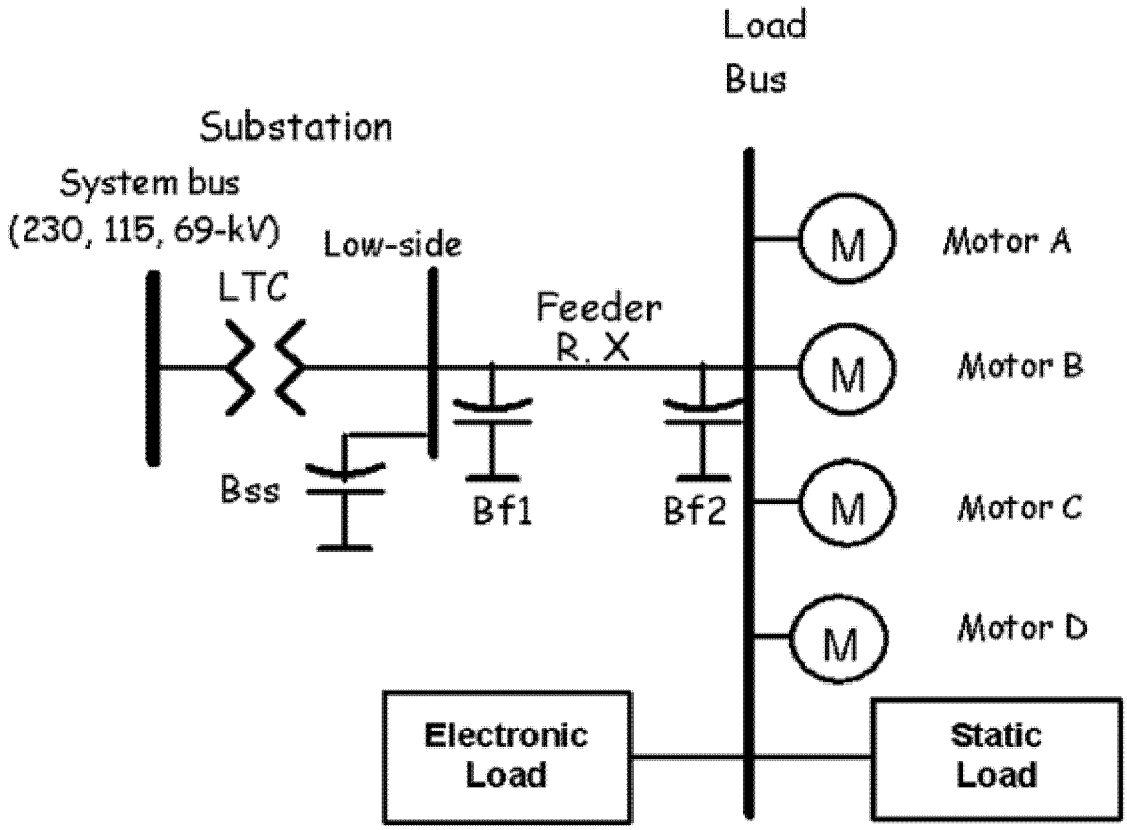

Figure 5-1 GE PSLF Composite Load Model CMPLDW

Table 5-2 Non-industrial Load Types

ID	Feeder Type	Residential	Commercial	Industrial	Agricultural
RES	Residential	70 to 85%	15 to 30%	0%	0%
COM	Commercial	10 to 20%	80 to 90%	0%	0%
MIX	Mixed	40 to 60%	40 to 60%	0 to 20%	0%
RAG	Rural	40%	30%	10%	20%

Table 5-3 Industrial Load Types

ID	Feeder Type
IND_PCH	Petro-Chemical Plant
IND_PMK	Paper Mill – Kraft process
IND_PMT	Paper Mill – Thermo-mechanical process
IND_ASM	Aluminum Smelter
IND_SML	Steel Mill
IND_MIN	Mining operation
IND_SCD	Semiconductor Plant
IND_SRF	Server Farm
IND_OTH	Industrial – Other
AGR_IRR	Agricultural irrigation loads
AGR_PMP	Large pumping stations with synchronous motors
PPA_AUX	Power Plant Auxiliary

5.3 2028 Study Data Sets

The original MTEP data set represented a 2023 shoulder load condition. This data set was modified to establish the 2028 light load, shoulder load and peak load cases. This involved adjusting the load in the MISO areas appropriately to represent 2028 conditions and adding the conceptual transmission plans identified in the thermal and voltage analysis. In going from shoulder load 2023 to 2028, a 0.5% annual load growth was assumed for Minnesota and 0.75% annual load growth was assumed for rest of the MISO. The load in the 2028 shoulder case was then modified to develop a 2028 light load and 2028 peak load case. The new wind and solar generation for each scenario (baseline, S1 and S2) were then added to the 2028 cases.

5.4 Dynamic Models for Renewables

The powerflow topology was modified to interconnect the new wind and utility-scale PV plants and distributed PV. These new plants have two transformations, one for the substation transformer and an equivalent for the unit transformer (from collector voltage to inverter voltage) with an intervening equivalent of the collector system. The arrangement is shown in Figure 5-2.

For dynamic modeling, the utility-scale PV plants are modeled with full four quadrant dynamic models (based on the Type 4 wind turbine generator [WTG] model) with voltage regulation and zero-voltage ride-through (ZVRT). The utility-scale PV plants are modeled with a power factor of ±0.90 at the inverter transformer. This gives an MVA rating of 1.11 times the plant MW rating, and reactive capability of ±0.436pu, based on the MVA rating. New wind plants were split roughly 50/50 between Type 3 double fed asynchronous generator (DFAG) and Type 4 (full converter) with voltage regulation and ZVRT. The new wind plants are modeled with a power factor of ±0.90 at the 690V

bus. This gives an MVA rating of 1.11 times the plant MW rating, and reactive capability of ±0.436pu, based on the MVA rating. Both wind and utility-scale PV were set to regulate the 690 V terminal bus. Although advanced WTG controls such as inertial response and frequency response were available in the models, they were assumed to be inactive. Furthermore, they were not required for mitigation during the dynamic analysis task.

Distributed PV was modeled as lumped generation in central locations, based on the siting work. The distributed PV was modeled with no reactive/voltage regulation capability. The ability of the distributed PV generation (DPV) to ride through voltage and frequency excursions is handled by a separate logic. The model allows selection of different levels of voltage and frequency excursion that will result in the DPV blocking. A further part of the logic allows specification of how much DPV will recover if the excursion returns within the user input bounds. The result is a high level of flexibility for modeling fault ride-through. However, the model does not support user input time delays on the blocking functions, and so is limited in its ability to reflect deliberate time thresholds for tripping (e.g., of the type in NERC low voltage ride through (LVRT) and IEEE 1547 standards).

Voltage ride through settings used for the DPV maintained full PV output between 0.90 pu and 1.10 pu voltage. Between 0.90 pu and 0.88 pu voltage, the DPV active power is run back linearly to zero. Below 0.88 pu voltage the PV is blocked. When voltage recovers above 0.9 pu the active power is restored. Similar logic is used for high voltage conditions between 1.1 and 1.2 pu.

Frequency ride through/blocking was modeled similar to voltage ride through/blocking. The DPV retains full output between 59.70Hz and 60.30 Hz. Between 59.70 Hz and 59.50 Hz the DPV active power runs back and is fully blocked below 59.5 Hz. However, unlike the voltage ride-through function, the PV active power does not recover after being blocked due to high or low frequency. There were no time delays model for the voltage or frequency ride through/blocking logic.

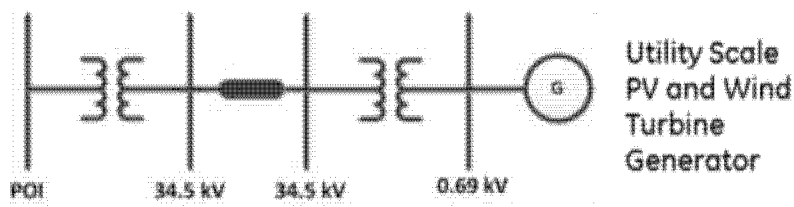

Figure 5-2 Renewable generation topology in powerflow Model

5.5 Monitoring Models and Performance Metrics

In order to quantify the effect of increased renewable generation on the system performance, several sets of metrics are developed. The metrics are geared towards identifying first swing stability, power swing damping and voltage response and recovery following a fault. Rotor angle of generators in the entire Eastern Interconnect are monitored to ensure if the system is transiently stable following each disturbance. Voltages are monitored for 220 kV and above buses throughout MISO.

In addition, a region-wide monitoring approach is used to identify issues that are not apparent from traditional stability plots. In this regard, a new dynamic model is developed to monitor regional performance. Regional metrics include measures such as, total rated MVA, rated MW, actual MW

and MVAR and reactive reserves for on-line synchronous generation and renewable generation. System measures such as regional load and interface flows are also monitored. The regional synchronous generation provides information about the short circuit strength of the region while the regional load and generator reactive power provides the understanding about regional voltage recovery following a disturbance. The percentage non-synchronous generation is also calculated from these measurements. These metrics are monitored dynamically and used to compare the high renewable system performance under various load conditions.

The geographical sub-regions and corresponding boundaries are defined based on the group of geographically coherent machines regardless of ownership and state boundaries. Altogether ten geographical subregions are defined for the study wherein six subregions constitute Minnesota Centric Region. Figure 5-3 shows the geographical subregion mapping with the regions shaded green being the Minnesota-Centric region. The assignment was confirmed after discussion with Technical Team members. The subregion assignment is used to evaluate the production simulation (Plexos) output for challenging periods as well as for obtaining the regional metrics for dynamic simulation. The geographical subregion is assigned to every generator in the entire Eastern Interconnect. Furthermore, all equipment including buses, generators, loads, lines, transformers are assigned subregion based on where they fit in the map shown in Figure 5-3. Table 5-4 lists the subregions and the names used to identify them.

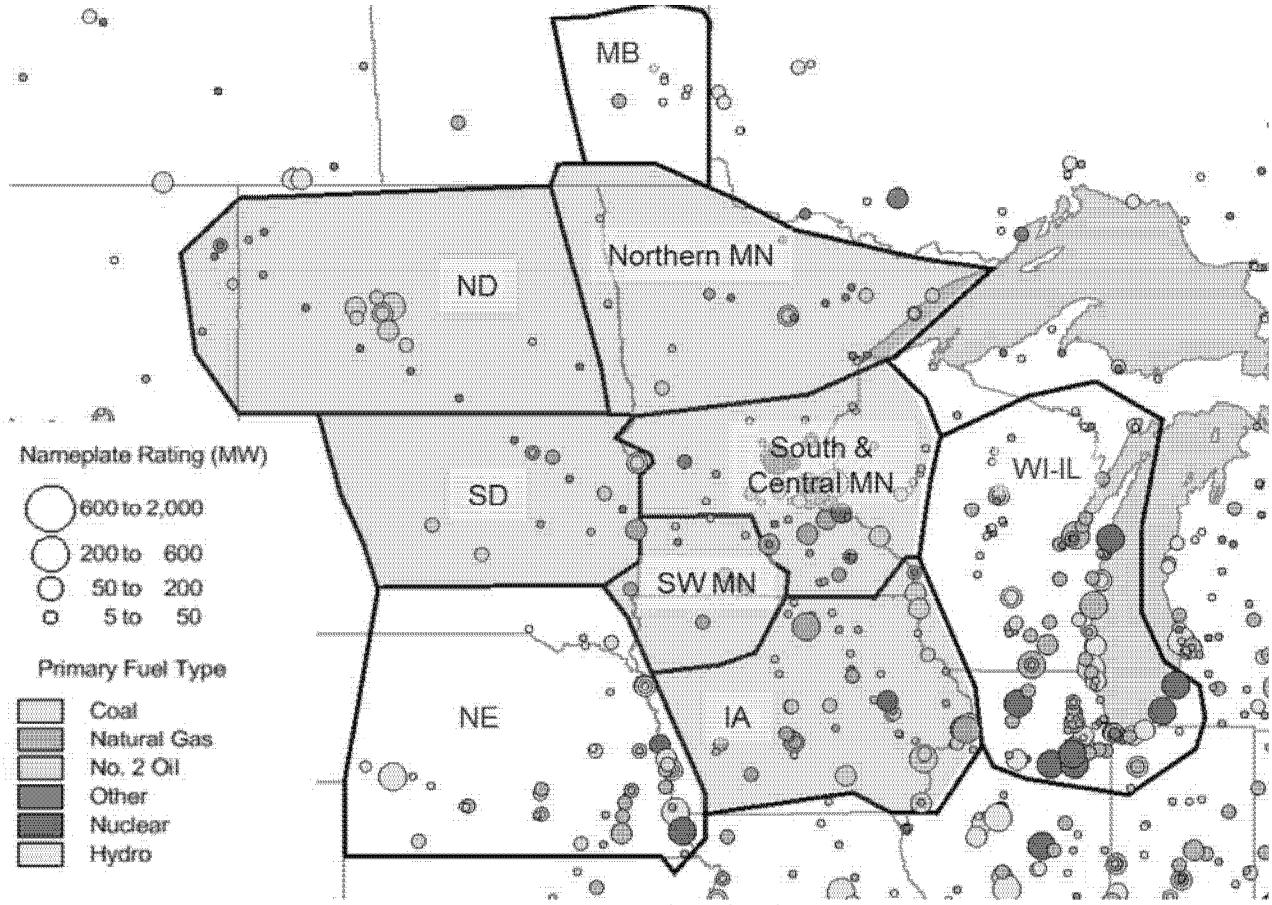

Figure 5-3 Geographical subregions

Table 5-4 Sub region assignment

Sub-Region No.	Name
1	Iowa
2	North Dakota
3	Northern Minnesota
4	South Dakota
5	South & Central Minnesota
6	SW Minnesota
7	Nebraska
8	Wisconsin & Illinois
9	Manitoba
10	Outside

A generic impedance relay model is used on all 220 kV and above the transmission lines throughout Eastern Interconnect. This model is used only for monitoring purpose and will not trip the lines in response to post fault voltage and current.

The instantaneous primary protection zone (Zone 1) is set to cover 85% of the primary line length. Zone 2 protection is delayed by 0.5 seconds and set for 125% of the primary line length. This model was used to identify possible system separation and voltage collapse issues in regions that were not explicitly monitored.

Figure 5-4 shows voltage performance criteria used by WECC. Worst conditions analysis is carried out to identify critical buses with respect to voltage dip and fault induced delayed voltage recovery. All 220 kV and above buses throughout MISO are monitored. With the idea of capturing large post fault transient voltage dip, buses with voltage dip below 20% of initial value for more than 20 cycles are identified. Another criterion is used to screen buses with voltage below 0.7 p.u. after fault clearing. In order not to capture low voltage during stuck breaker faults, where the fault clearing times are longer, the latter criterion is applied 0.15 sec after fault application.

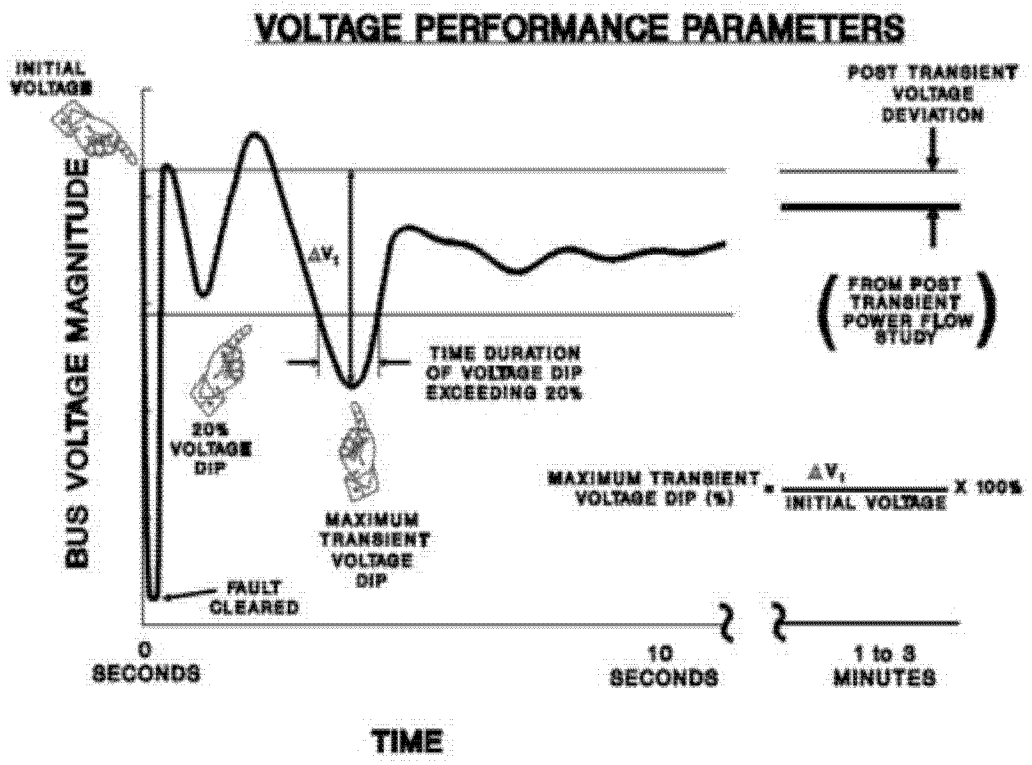

Figure 5-4 Voltage performance metrics

6 PRODUCTION SIMULATION MODEL

6.1 Overview of Production Simulations

The Minnesota Renewable Energy Integration and Transmission Study (MRITS) analyzed three scenarios (Baseline, S1, and S2). The baseline scenario represents the generation, transmission and market system in 2028 if current industry and economic trends continue. S1 represents a future where baseline trends continue, along with Minnesota increasing its renewable penetration to 40% along with small Non-MN distributed solar in MISO. S2 represents a future where baseline trends continue, along with Minnesota increasing its renewable penetration to 50%, and MISO North/Central increases its renewable penetration to 25%.

PLEXOS™, an integrated energy model, was used to do the production simulations. The PLEXOS model was constructed from the existing 2013 MTEP Business As Usual (BAU) dataset for the study year 2028. Then S1 was built from the Baseline by adding new wind and solar generation and transmission upgrades, and S2 was built from S1 by adding yet more wind and solar generation, removing some expansion gas generation and adding additional transmission.

6.2 PLEXOS Overview

PLEXOS was chosen because it can utilize a Day-Ahead Security Constrained Unit Commitment (SCUC) and Real-Time Security Constrained Economic Dispatch (SCED) interleaved market dispatch solution. This type of interleaved modeling, with one simulation feeding into the other, more accurately captures the forecast uncertainties realized between a Day-Ahead and Real-Time markets. Modeling the forecast uncertainty becomes increasingly important when dealing with significant levels of wind resource output which tends to be more stochastic in nature.

Performing an economic production simulation was a principal aspect of the MRITS study to correctly model how the MISO system operates. The vast amount of hourly output such an analysis generates can be crucial in understanding which time periods are the most significant to analyze further. It also provides valuable insight into transmission system utilization, power system flows, and renewable unit curtailment.

6.3 MRITS Production Simulation Model – Source Dataset

MISO used the 2013 MTEP Business as Usual (BAU) future as the source dataset (starting point) for the MRITS analysis. The BAU future is considered the status quo future and continues current economic trends. This future models the power system as it exists today with reference values and trends. Renewable portfolio standards vary by state and 12.6 GW of coal unit retirements are modeled. The MTEP futures are created by MISO and vetted by the MISO Planning Advisory Committee (PAC) stakeholder committee. Information for the dataset is sourced from Ventyx and updated through an extensive internal MISO process to bring it into line with the most current data.

The PLEXOS model footprint includes all areas in the Eastern Interconnect, with the exception of Florida, ISO New England and Eastern Canada as shown in Figure 6-1. Figure 6-2 shows the MISO market footprint. MISO is modeled using membership information dated as of January 2014.

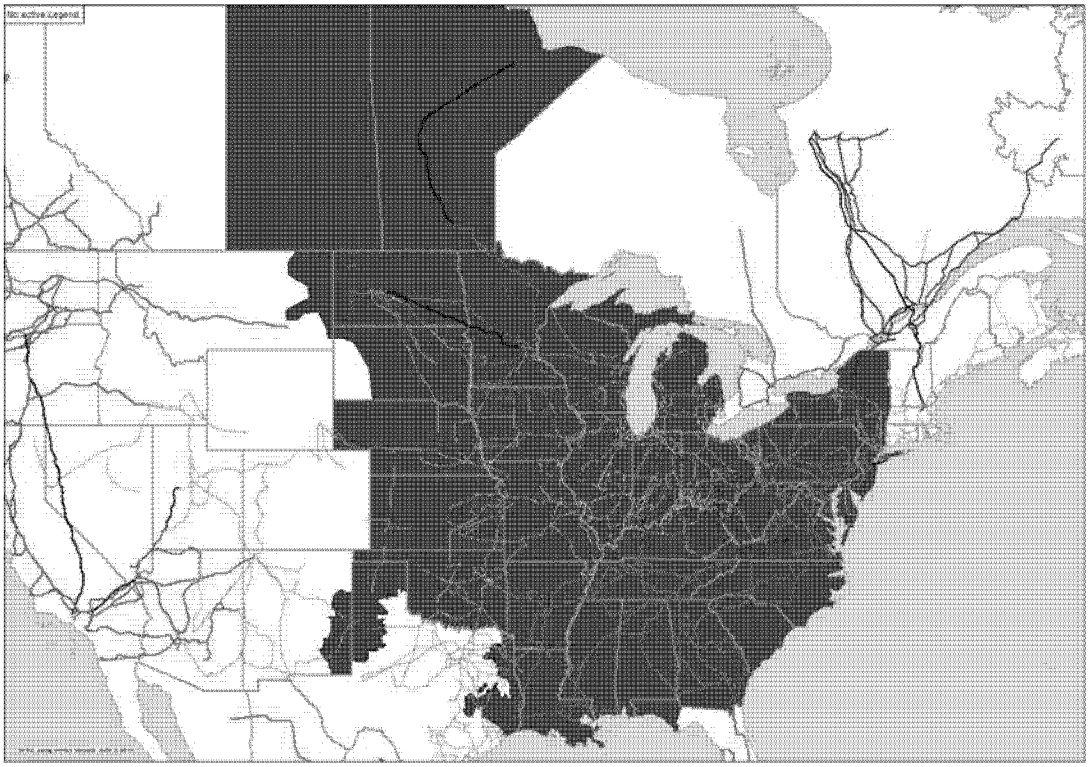

Figure 6-1 Study Footprint

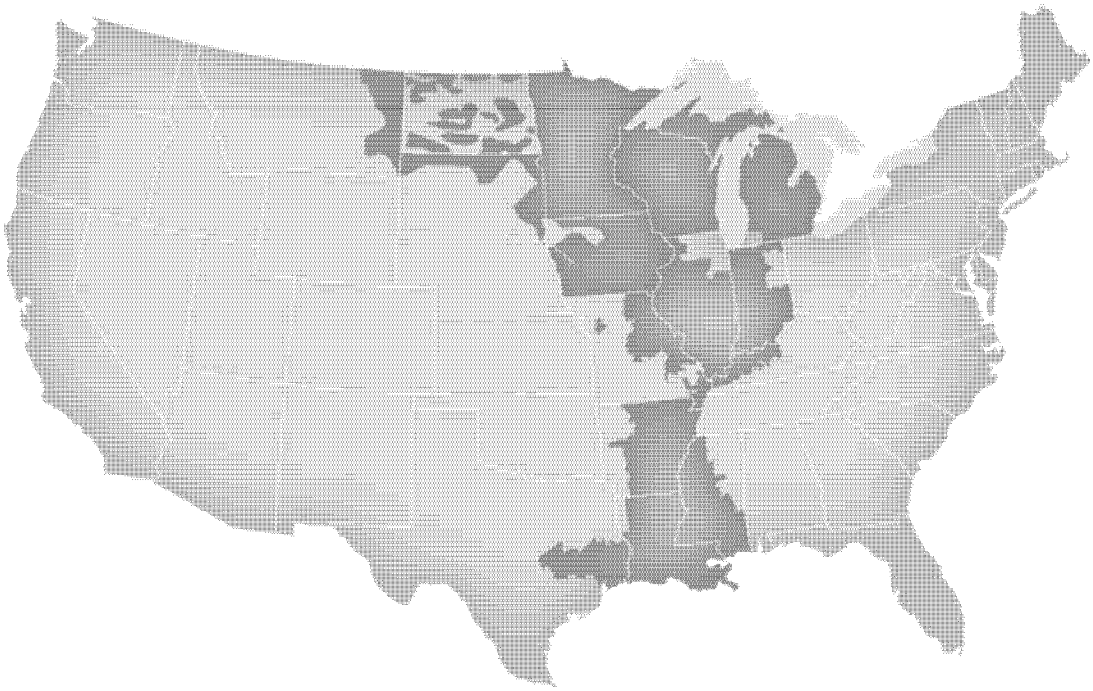

Figure 6-2 MISO's Market Footprint

As part of the MTEP BAU future development process, capacity was added to meet the various planning reserve margin requirements. Renewable resources were added to meet the various state renewable portfolio standards, shown in Figure 6-3, throughout the Eastern Interconnect.

Also between 2013 and 2028, 24,900 MW of capacity was added to MISO to meet the planning reserve margin (14.2%), and 12,200 MW of coal was retired in MISO due to the forecasted effects of prior EPA regulations as shown in Figure 6-4. This does not include coal plant retirements that may result from the EPA's proposed Clean Power Plan (111d).

Capacity additions include wind and demand side resources to meet state mandates along with gas units because of the low natural gas price. Demand and Energy Growth Rate was 1.06%, and all prices escalate at an inflation rate of 2.5%.

Wind and solar plant output was modeled at specific locations with each site having a unique historically based output as demonstrated in Figure 6-5. [1].

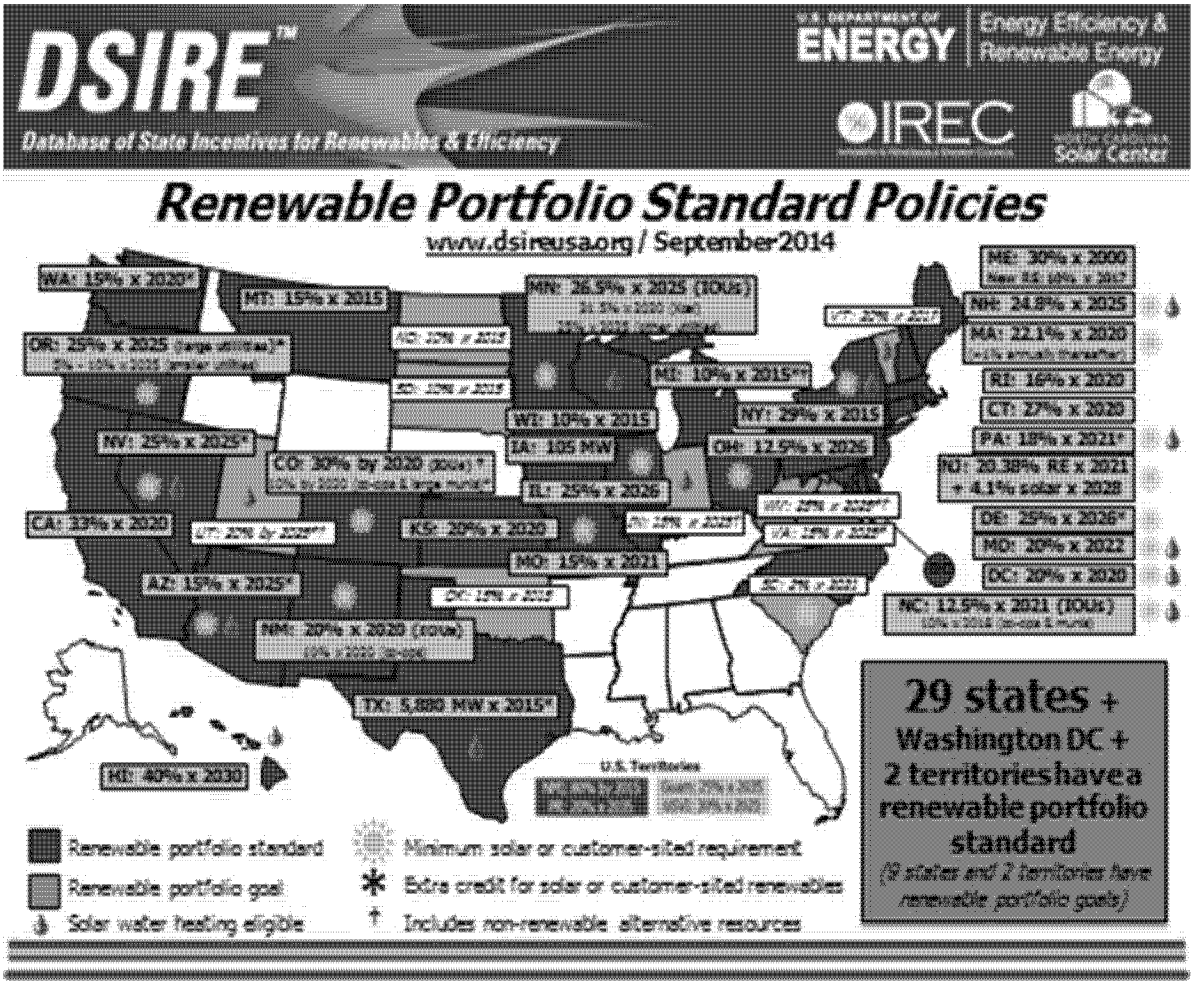

Figure 6-3 State Renewable Portfolio Standard Policies used in the MTEP13 Model

[1] http://www.dsireusa.org/summarymaps/index.cfm?ee=0&RE=0

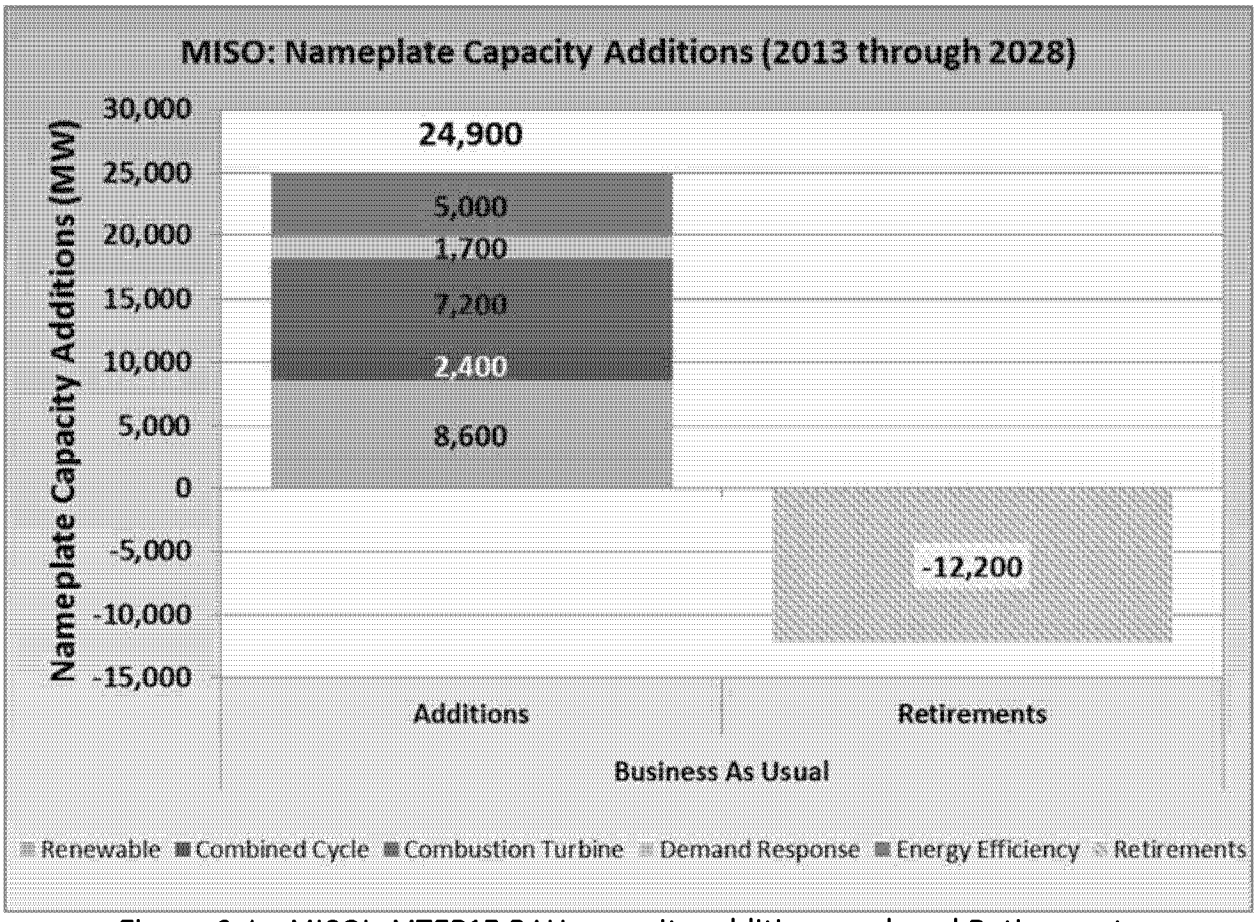

Figure 6-4 MISO's MTEP13 BAU capacity additions and coal Retirements before changes were made as shown in Figure 6-6 (2013-2028)

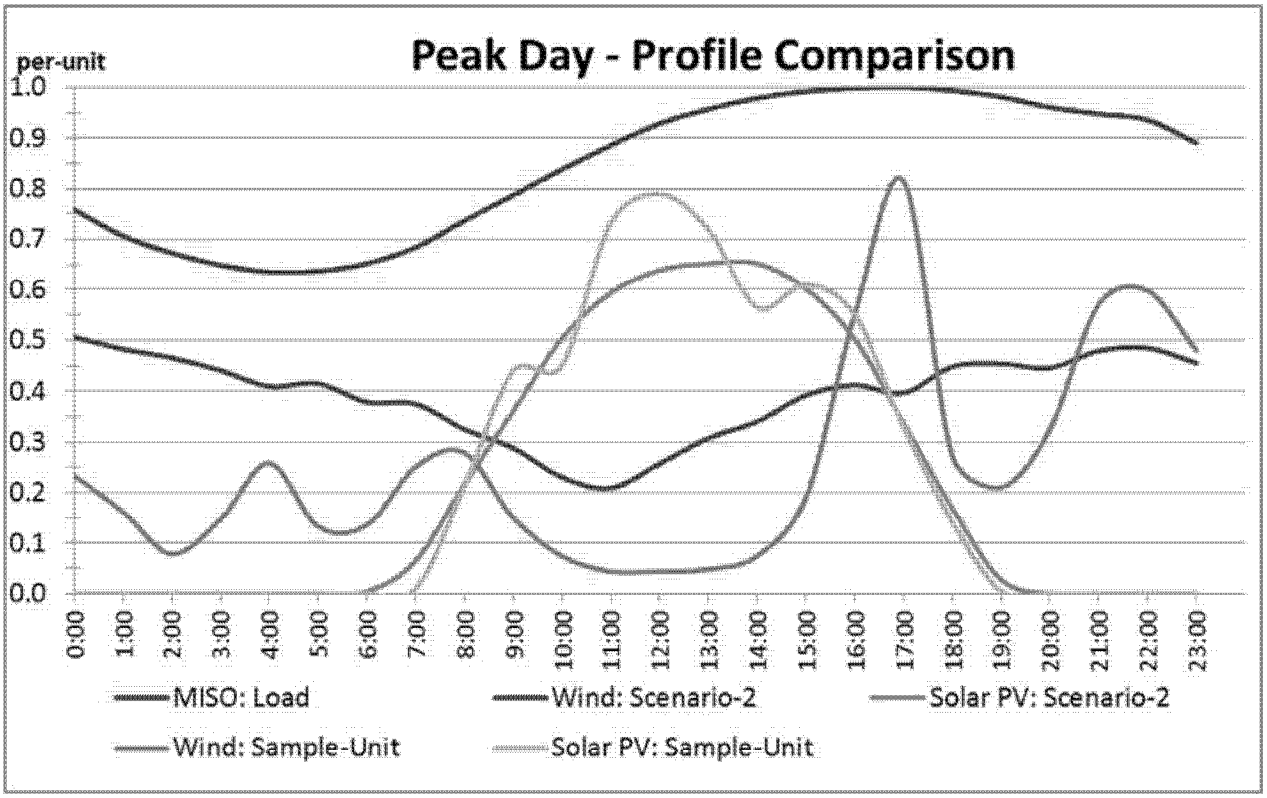

Figure 6-5 Illustration of site specific renewable output

6.3.1 Baseline Scenario

MRITS held slightly different assumptions than the 2013 MTEP BAU future, thus the baseline database needed to be modified to reflect these new assumptions. Wind resources used the same assumptions that the MTEP BAU future did, but solar units were adjusted. The forecasted solar units, totaling 1725 MW, in MISO were removed and 1509 MW of new solar generation was added to the Baseline model per MRITS assumptions.

The siting locations of these units were also changed to reflect a more realistic distribution of solar resources which is explained in the Siting Section. A proxy expansion hydro unit in Manitoba Hydro was removed and replaced with Keeyask, a 695MW unit that has become certain (approved and under construction) since the 2013 MTEP models were built. The 500kV Great Northern transmission line was also added to deliver this hydro power.

6.3.2 Scenarios 1 and 2

Scenario 1 and 2 had different capacity assumptions than the baseline case did so a new capacity expansion was done to reflect these different assumptions. Renewable capacity was increased and thermal capacity was decreased to maintain the same capacity reserve margins as shown in Figure 6-6. The treatment of capacity credit for wind and solar resources is discussed in the following subsection.

Thermal capacity was not reduced for Scenario 1 because capacity reserves were slightly over the requirement in 2028 given the lumpiness of capacity additions, in other words, the generation is not

added in smooth incremental amounts but rather the generation is added in larger blocks. In scenario 2, enough renewables were added to warrant the reduction in thermal capacity.

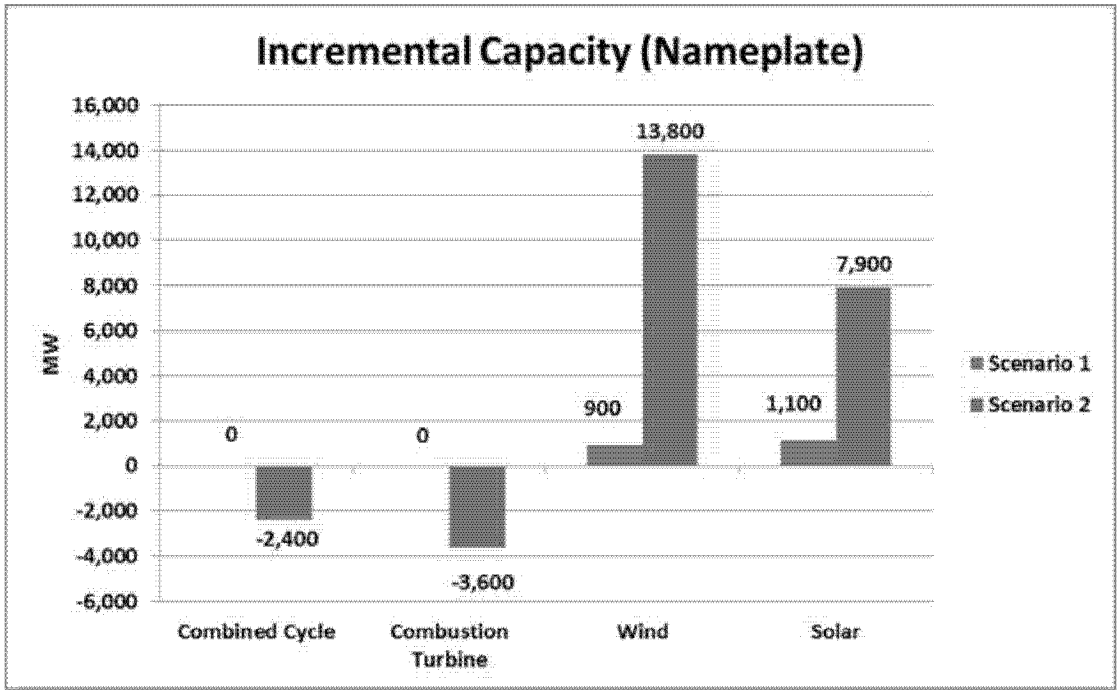

Figure 6-6 Resource Capacity Changes for Scenarios 1 and 2

6.3.3 Capacity Credit for Wind and Solar Resources

A capacity credit value was needed for the wind and solar renewables in order to perform the resource forecasting capacity expansion. For each of those resource types a currently developed MISO process was utilized to determine what capacity value to use for the MRITS study.

The resulting capacity credit values were:

Baseline and S1 Wind:	14.1%
S2 Wind:	11.8%
Solar:	40 %

6.3.3.1 Wind Capacity Value

For the wind capacity credit, this study referred to the MISO report[2] findings.

Both the Baseline and Scenario1 models used the value of 14.1% of nameplate. Those cases both have levels of wind energy penetration, 14% and 15.2% respectively, which are close to the current MISO system amount of 13%, installed.

[2]Planning Year 2014-2015, Wind Capacity Credit, https://www.misoenergy.org/Library/Repository/Study/LOLE/2014%20Wind%20Capacity%20Report.pdf

But for Scenario 2 which had a significant increase in the MISO penetration of wind to 23.8%, the Figure 6-7 from the report[3] was used to interpolate a capacity value of 11.8% for wind. In the higher wind penetration regions, 15%+, as the figure shows, the wind capacity credit decreases due to a saturation of wind energy during peak times. Note that the figure shows only the 20 GW and 30 GW penetration data points and these were converted to 21.2% and 31.8% penetration, respectively, based on the 94,298 MW 2013 MISO Peak Load used for that figure.

6.3.3.2 Solar Capacity Value

For the solar capacity value, this study referred to the MISO Resource Adequacy Business Practice Manual[4] rules for non-wind, intermittent resources. The manual[5] indicates that the following be used:

> "Intermittent Generation and Dispatchable Intermittent Resources that are not powered by wind must supply MISO with the most recent consecutive three years of hourly net output (in MW) for hours 1500 – 1700 EST from June, July and August. For new resources, or resources on qualified extended outage where data does not exist for some or all of the previous 36 historical months, a minimum of 30 consecutive days' worth of historical data during June, July or August for the hours of 1500 - 1700 EST must be provided."

So using only data during that prescribed time period and the 2006 NREL solar set of information provided for the sites used in the MRITS study, a capacity value of 40% of solar nameplate was calculated based on the capacity factor deterministic approach.

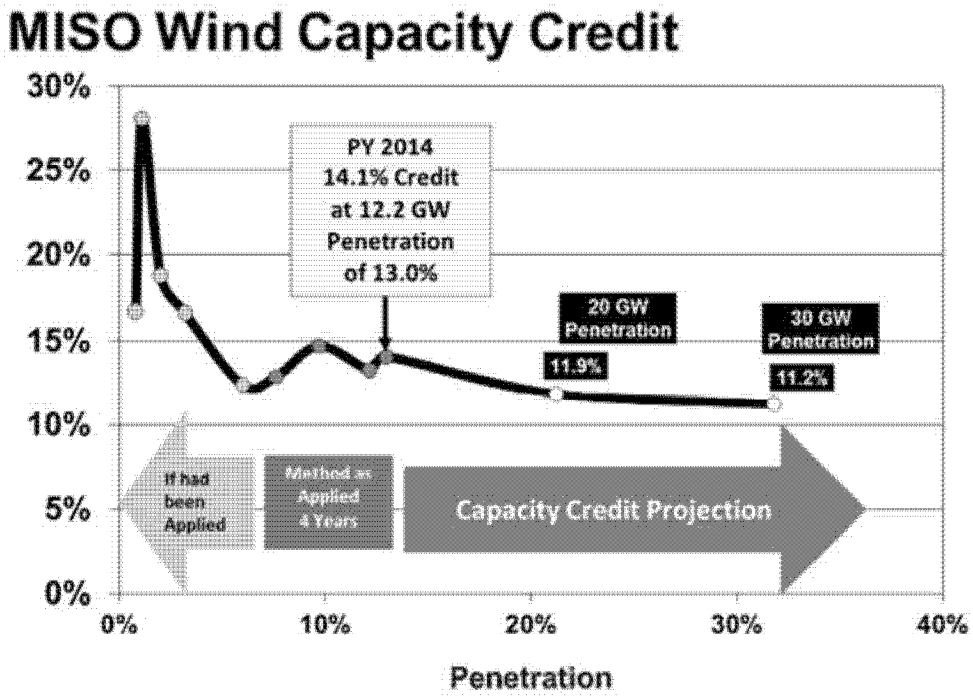

Figure 6-7 Plot of Wind Capacity Credit versus Penetration Level, from MISO Report

[3] https://www.misoenergy.org/Library/Repository/Study/LOLE/2014%20Wind%20Capacity%20Report.pdf
[4] https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=19206
[5] Ibid. Section 4.2.2.1 (page-34)

The 40% capacity factor for solar was used in the resource forecasting step when determining which and how many other non-renewable resources to add to maintain the planning reserve margin in the future year.

For the load-flow analysis, it was decided to further stress the transmission system with a higher value of solar output beyond its capacity factor rating. A scatter plot of wind vs. solar output was compiled which can be seen in Figure 6-8. This figure shows that when the wind output is in the range of 20% as during peak load-flow type conditions or when it's at a 90% range during off-peak load-flow type conditions, solar output could be in the high range of 60%. Based on that high range level value, 60% was chosen as the load-flow assumption level for solar.

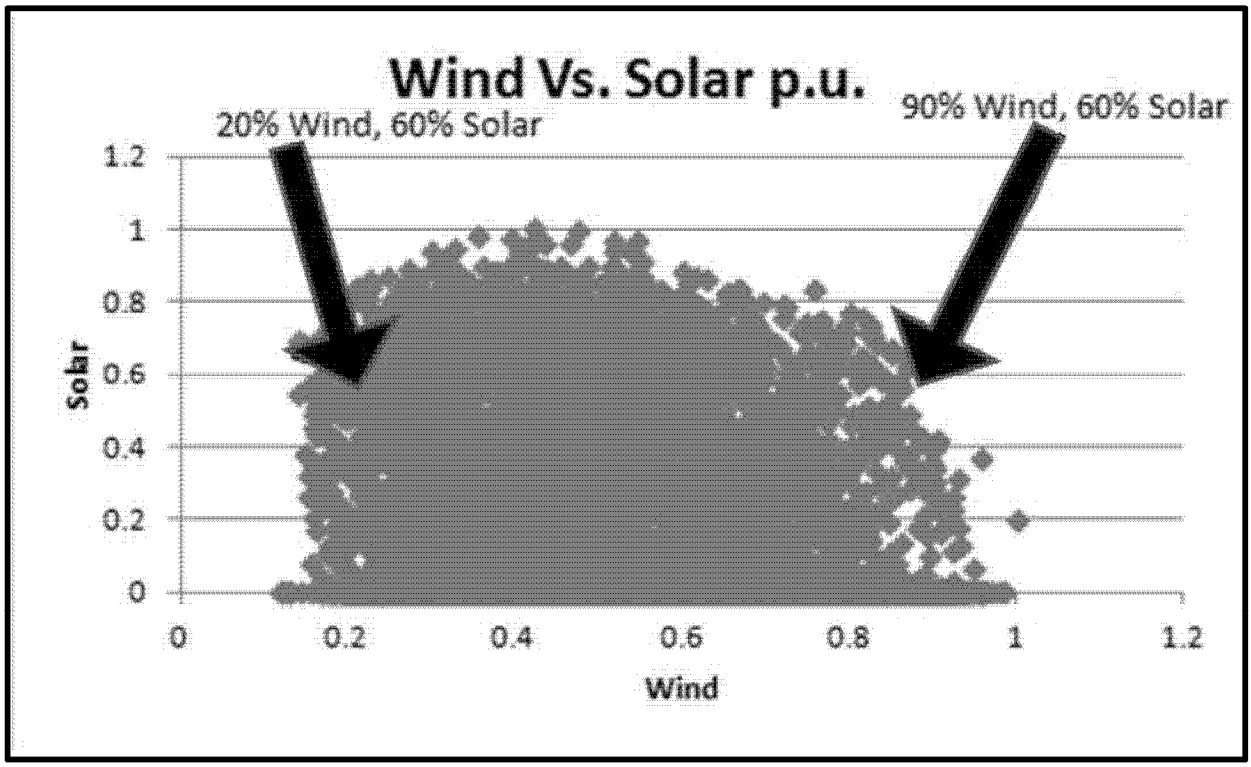

Figure 6-8 Scatter Plot of Wind versus Solar Output

6.3.4 Forecast Uncertainty

The MRITS study incorporates wind, solar and load uncertainty to more accurately reflect the challenges associated with large scale renewable integration. Renewable profiles were provided by the National Renewable Energy Lab (NREL).

Wind uses the NREL EWITS wind dataset:	Unit commitment uses the 4-hour ahead wind profile Dispatch uses the actual wind site output
Solar uses the NREL ERGIS solar dataset:	Unit commitment uses a MISO aggregate solar profile. Dispatch uses the actual solar site output
Load uses historic load data:	Unit commitment uses a stochastic load profile. Dispatch uses the historic actual profiles

6.3.4.1 Wind

All 2006 wind data comes from the NREL EWITS wind data set. Two separate wind forecasts were considered, the Next Day (ND) and the 4-hour ahead (4HR) as shown in Figure 6-9. The plot shows normalized traces of hourly wind power for one week. The 4 hour wind forecast provided by NREL was used as this more accurately approximates the final generation commitment MISO would have going into the Real Time market. The Actual output is the estimated wind that was actually produced for the given hour as provided by NREL[6]..

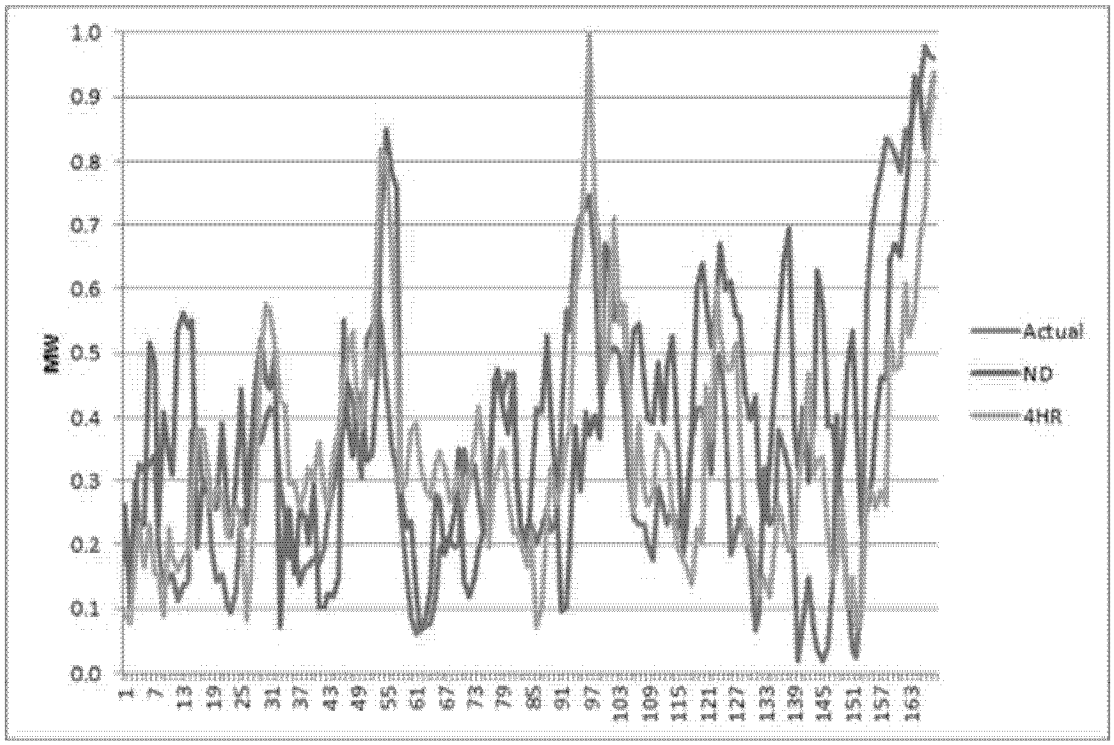

Figure 6-9 Sample of Hourly Forecast and Actual Wind Site Output (1st week of July)

[6] http://www.nrel.gov/electricity/transmission/wind_integration_dataset.html

6.3.4.2 Solar

Actual real time solar data comes from NREL. It is a combination of Eastern Renewable Generation Integration Study (ERGIS) data for non-Minnesota sites and newly created data for Minnesota sites. The forecast is created by summing all profiles together and creating a single shape for the entire region. This shape is scaled back down to the size of each individual solar site.

The forecast will take into account wide spread cloudiness since it is the aggregate of the actual profiles, but spotty clouding will be washed out because of the aggregation. The solar arc can be perfectly forecasted but cloud cover creates the uncertainty in the forecast.

Figure 6-10 shows the output of 2 Solar Sites, and demonstrates the differences between individual locations, and how they each compare to the forecast. Solar output is shown as a percentage of its Direct Current rating.

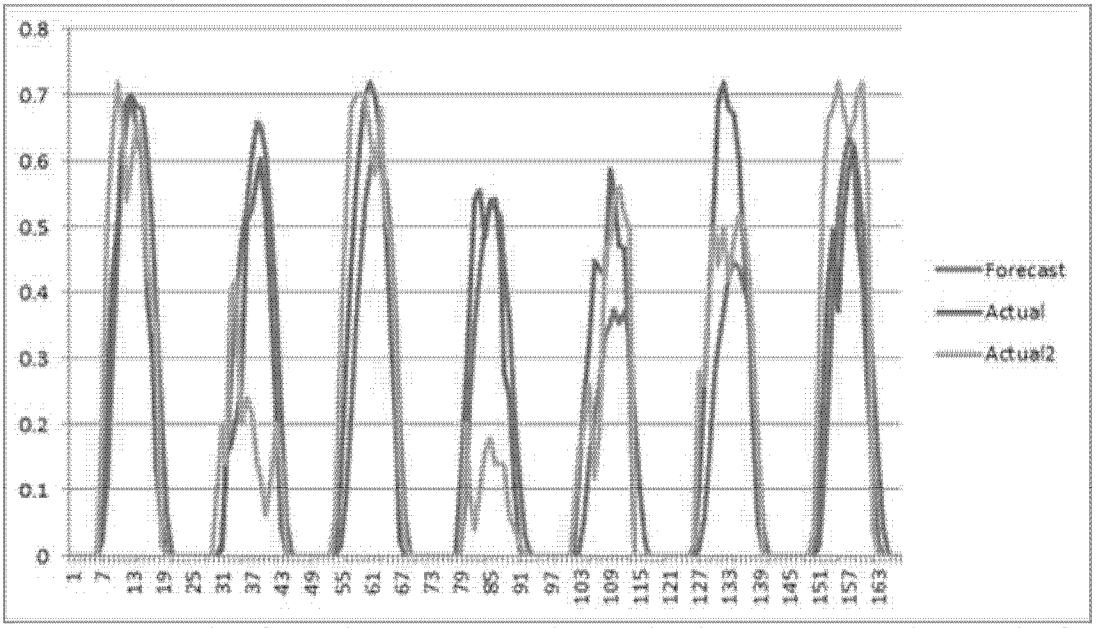

Figure 6-10 Sample of Hourly Forecast and Actual Solar Site Output (1st week of July))

6.3.4.3 Load

Actual load profiles are historic 2006 shapes. Forecasts are created by compiling statistics from the MISO market between 2008 and 2011 and applying those to the actual shapes. A random draw was done using these statistics to simulate the historic differences between the forecast and the actual load. The day-ahead load forecast was used and not a 4-hour forecast because the day-ahead is a discrete and separate forecast while the 4 hour is simply a snapshot of the rolling forecast.

Figure 6-11 shows a sample of load for a week, along with the random draw forecast which was used for this study.

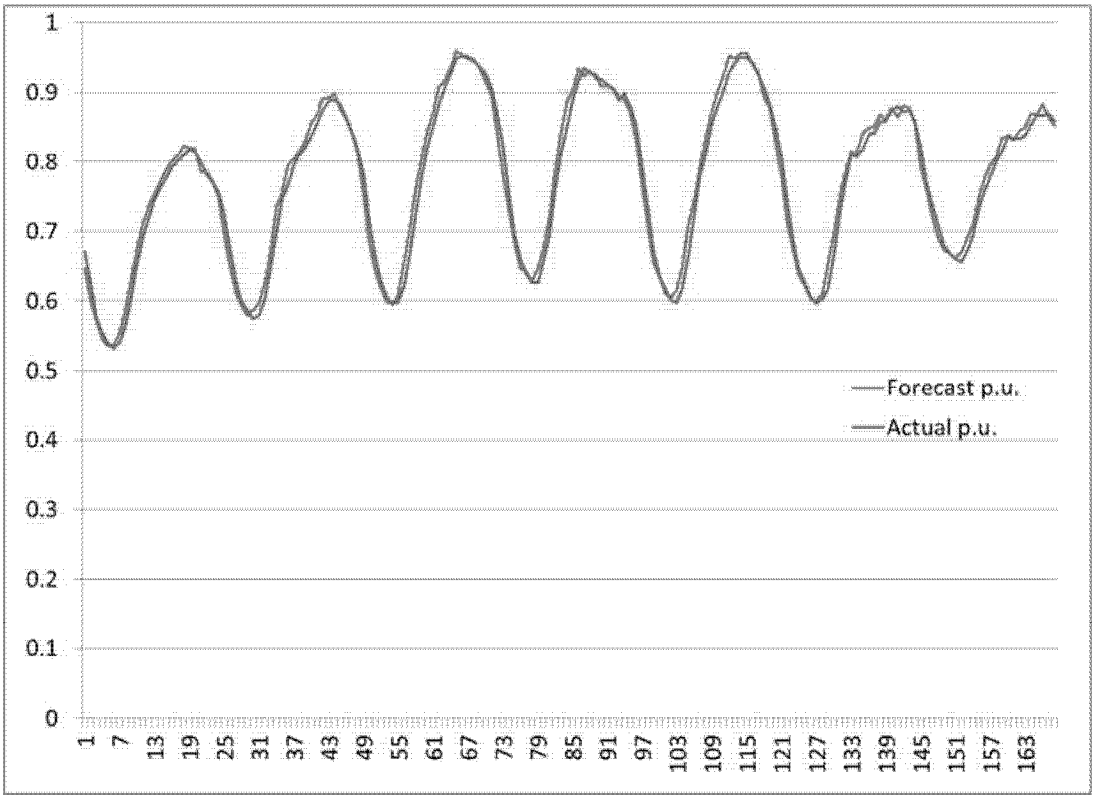

Figure 6-11 Sample Minnesota Load Output (1st week of July)

7 OPERATIONAL PERFORMANCE RESULTS

7.1 Scenarios for Production Simulation Analysis

As described in Chapter 2, the study was designed to evaluate scenarios with three levels of renewable energy (RE) penetration in Minnesota (see Table 7-1). These 3 levels of RE penetration were analyzed with five production simulation cases. Two of the five cases had different assumptions for coal plant commitment, forced outage modeling, coal unit retirements, and modeling of the Missouri River hydro plants. The modeling assumptions for each case are summarized in Table 7-2. Scenario 1a is a sensitivity case with respect to Scenario 1. That is, Scenarios 1 and 1a have the same renewable energy penetration, but with different system operating assumptions. Similarly, Scenario 2a is a sensitivity case with respect to Scenario 2. Thus, the original three scenarios expanded to five scenarios for this aspect of the technical analysis.

Table 7-1 Study Scenarios

Scenario	Minnesota RE Penetration	MISO Wind & Solar Penetration (including MN)
Baseline	28.5%	14.0%
Scenario 1	40.0%	15.0%
Scenario 2	50.0%	25.0%
Note: MISO has an additional 3% renewable energy penetration in all scenarios from existing small biomass and small hydro.		

Table 7-2 Major Assumptions for Production Simulation Analysis of Study Scenarios

	Baseline	Scenario 1	Scenario 1a	Scenario 2	Scenario 2a
Coal plants modeling: Must-run (MR) or Security-Constrained Economic Commitment (SCEC)	MR	MR	SCEC	MR	SCEC
Forced outages included in generation modeling	No	No	Yes	No	Yes
Nine Minnesota-Centric coal units retired	Yes	Yes	No	Yes	No
Improved modeling of Missouri River hydro generation	No	No	Yes	Yes	Yes

Minnesota load is served by a group of utilities and cooperatives with service territories that extend beyond the boundaries of the State of Minnesota. Therefore, the results of the production simulation analysis are summarized for the "Minnesota-Centric Region", which consists of all generating resources operated by and system loads served by the Minnesota utilities.

Figure 7-1 shows a map of the Minnesota-Centric Region. The dots represent generating stations owned and operated by the Minnesota Utilities. The individual utilities are listed in the figure.

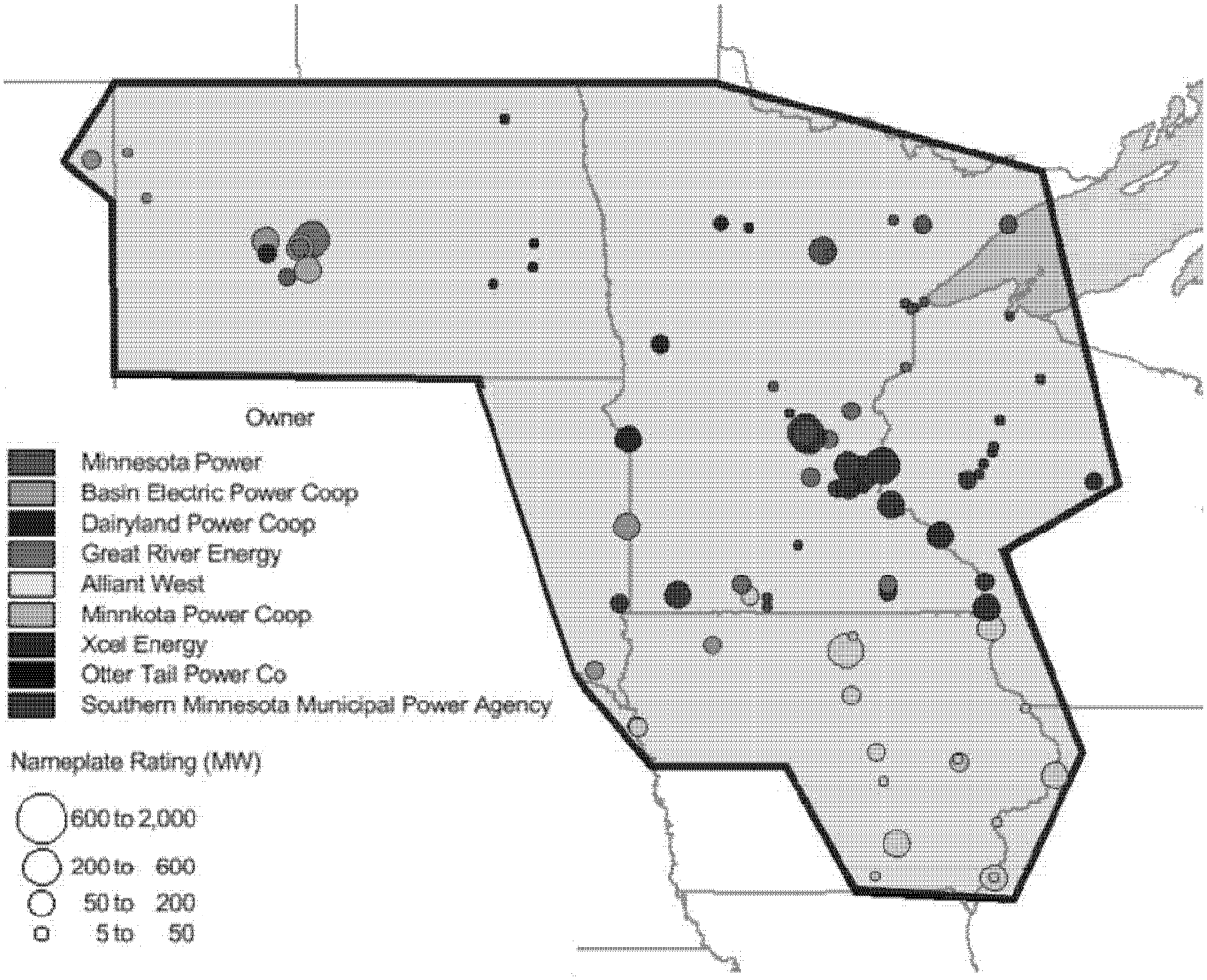

Figure 7-1 Minnesota-Centric footprint for production simulation (Plexos) Analysis Dots indicate generating plants owned by Minnesota Utilities.

7.2 Annual Energy

Table 7-3 shows annual load, wind and solar energy for the Minnesota-Centric region for the study scenarios. The system load energy is, of course, the same for all scenarios. The bottom two rows show the MW rating of assumed wind and solar generation resources in the Minnesota-Centric region, which increase from the Baseline, to Scenarios 1/1a, and then further increase to the values in Scenarios 2/2a.

Note that the wind and solar energy penetration levels shown in this table are for the Minnesota-Centric Region and not specifically for the State of Minnesota. The amount of wind and solar generation resources included in the system models was calculated to meet the Minnesota RE penetrations specified in the study objectives (see Chapter 3).

In the production simulation analysis, the energy is summarized by "owner" (i.e., the utility which owns the bus where the generation is connected) consistent with the operation of the system. Therefore, the wind and solar energy penetration levels shown in the table are calculated for the entire Minnesota-Centric region, which includes all generating resources operated by and system loads served by the Minnesota utilities.

The results show that wind and solar curtailment is relatively small in all the scenarios. The levels of curtailment are considered to be within reason and not sufficient to be of concern. Experience from grid operations and from other renewable integration studies has shown that it is not economically justifiable to eliminate all causes of curtailment for all hours of the year. A small amount of curtailment is to be expected for any system.

Further analysis of wind and solar curtailment is presented in a subsequent section of this report.

Table 7-3 Annual Load, Wind and Solar Energy for Minnesota-Centric Region

	Baseline	Scenario 1	Scenario 1a	Scenario 2	Scenario 2a
Load Energy (MWh)	147,807,020	147,807,020	147,807,020	147,807,020	147,807,020
Available Wind Energy (MWh)	37,286,193	45,753,928	45,753,928	61,789,277	61,789,277
Delivered Wind Energy (MWh)	37,129,632	45,298,460	45,025,066	60,467,557	60,799,826
Curtailed Wind Energy (MWh)	156,561	455,468	728,862	1,321,700	989,451
Curtailed Wind Energy	0.42%	1.00%	1.59%	2.14%	1.60%
Available Solar Energy (MWh)	702,562	2,002,969	2,002,969	6,870,164	6,870,164
Delivered Solar Energy (MWh)	701,936	2,002,869	1,998,268	6,841,300	6,853,503
Curtailed Solar Energy (MWh)	626	100	4701	28,864	16,661
Curtailed Solar Energy	0.09%	0.00%	0.23%	0.42%	0.24%
Wind Penetration	25.12%	30.65%	30.46%	40.91%	41.13%
Solar Penetration	0.48%	1.36%	1.35%	4.63%	4.64%
Wind+Solar Penetration	25.60%	32.00%	31.81%	45.54%	45.77%
MW Rating of Wind Fleet	11,039	12,970	12,970	18,140	18,140
MW Rating of Solar Fleet	470	1367	1367	4588	4588

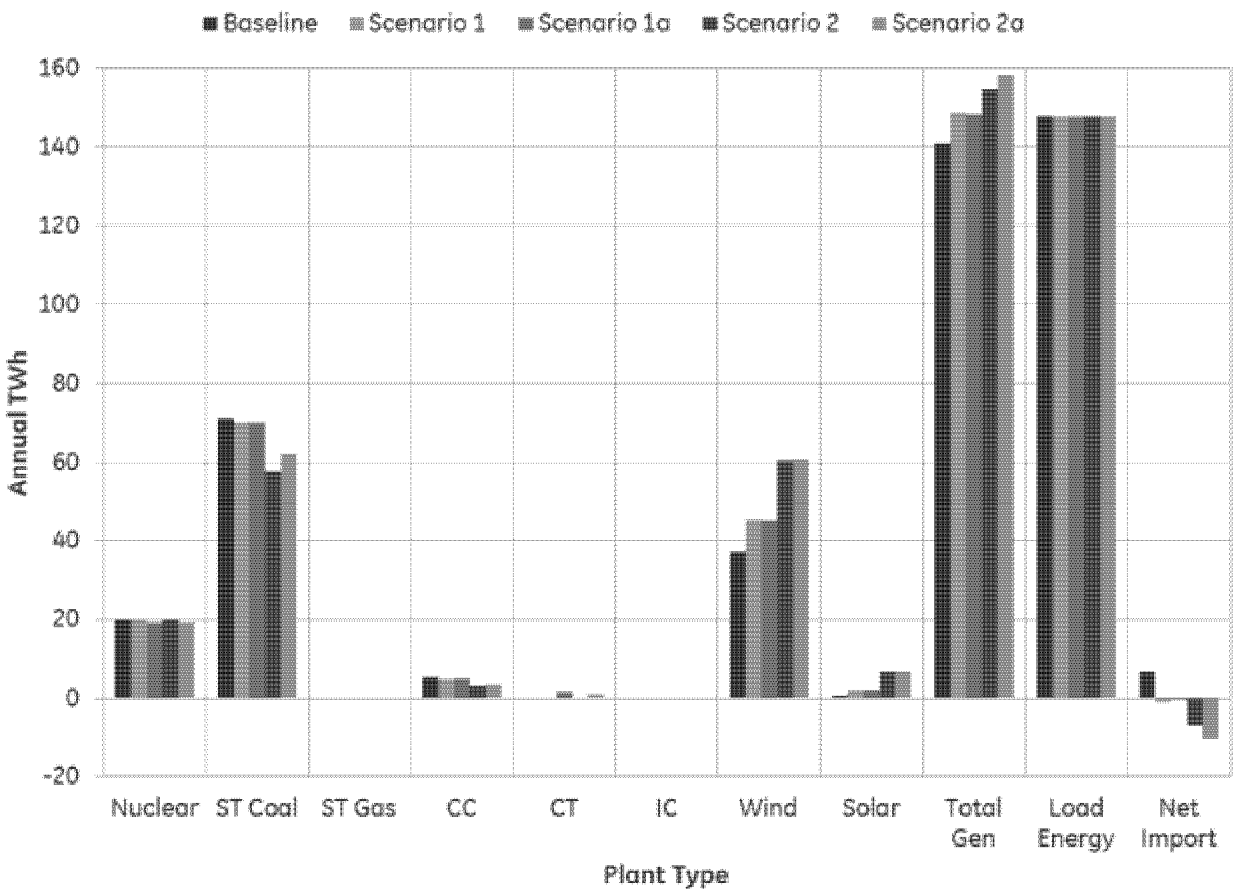

Figure 7-2 Annual generation in TWh by unit type for Minnesota-Centric region

Figure 7-2 shows the annual load and generation energy by type for the Minnesota-Centric region. Comparing Scenarios 1 and 1a (40% MN renewables) with the Baseline,

- Wind and solar energy increases by 8.5 TWh, all of which contributes to bringing Minnesota from 28.5% RE penetration to 40% RE penetration
- There is very little change in energy from conventional generation resources.
- Most of the increase in wind and solar energy is balanced by a decrease in imports
- The slight reduction in nuclear energy in Scenario 1a is due to forced outages.

Comparing Scenarios 2 and 2a (50% MN renewables) with Scenarios 1 and 1a (40% MN renewables),

- Wind and solar energy increases by 20 TWh. Of this total, 4.8 TWh brings Minnesota from 40% to 50% RE penetration and the remainder contributes to bringing MISO from 15% to 25% RE penetration
- Most of the increase in wind and solar energy in the Minnesota-Centric region is balanced by a decrease in coal generation and imports from neighboring regions

- Gas-fired combined-cycle generation declines from 5.0 TWh in Scenario 1 to 3.0 TWh in Scenario 2

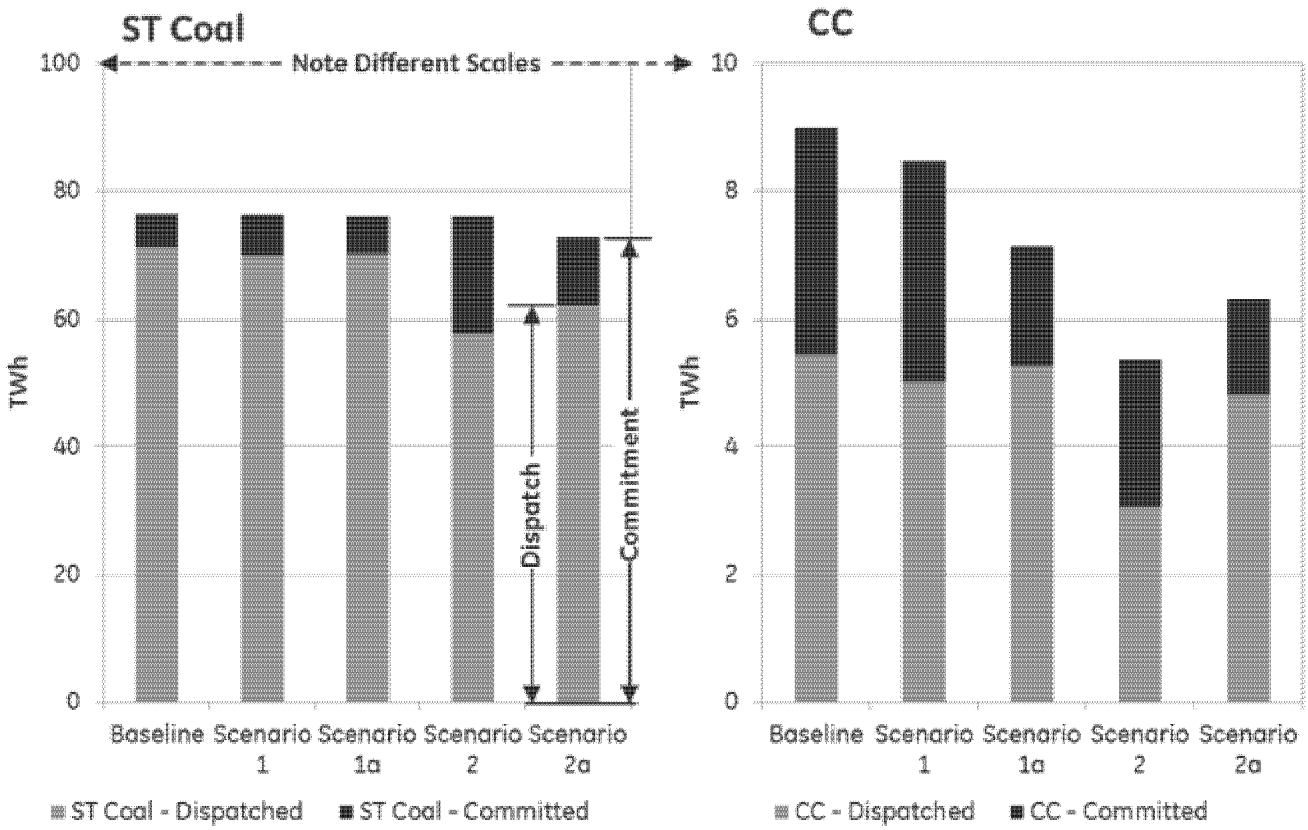

Figure 7-3 Annual Committed Capacity and Dispatch Energy for Coal and Combined-Cycle Units in the Minnesota-Centric Region

The left side of Figure 7-3 shows annual committed capacity and dispatched energy for coal units. In this figure, the total height of each bar indicates total annual coal unit committed capacity for the Minnesota-Centric Region. This is calculated by multiplying the hours online by the unit rating for each coal unit, and then totaling the values for all coal units. The light-blue segment of each bar is the energy dispatched (generated) from the coal units (i.e., the sum of energy output for all hours for all coal units). Comparing the Baseline with Scenarios 1 and 1a, there is no significant difference in coal unit commitment or dispatch. In Scenario 2, the dispatched energy from the coal units declines relative to the previous scenarios due to the increase in wind and solar generation. However, the coal fleet commitment remains nearly the same because many coal units in Scenario 2 are assumed to be must-run and are not decommitted during periods of high wind and solar generation. In Scenario 2a, all coal units are economically committed/decommitted per market signals, so the overall commitment of the coal fleet is lower than in Scenario 2. Note that the coal fleet dispatch in Scenario 2a is higher than Scenario 2. This is because Scenario 2 assumes that 9 coal units in the Minnesota-Centric region would be retired and Scenario 2a assumes that those units would be available to operate.

The right side of Figure 7-3 shows similar information for the combined-cycle fleet. Comparing Scenarios 1 and 1a with Scenarios 2 and 2a, it is evident that utilization of the combined cycle fleet declines as wind and solar energy increases.

The figure also indicates that CC fleet operation is more efficient in Scenario 1a (with coal units economically committed) than in Scenario 1 (with coal units assumed to be must-run). That is, the dispatched CC fleet energy output is a higher percentage of the CC fleet commitment. A similar observation can be made by comparing Scenario 2a with Scenario 2.

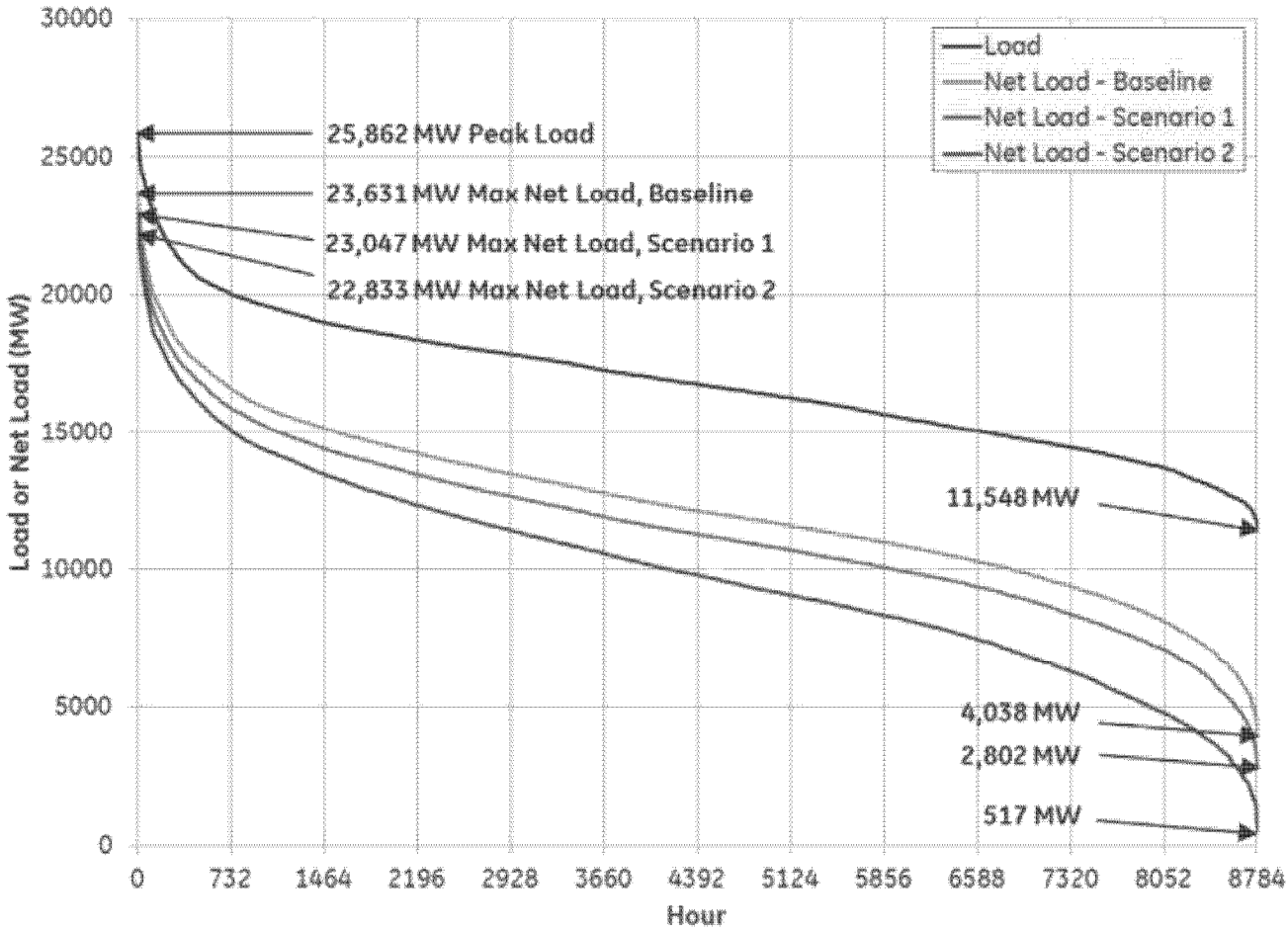

Figure 7-4 Annual Load and Net Load Duration Curves for Minnesota-Centric Region

The annual load and net load[1] duration curves for the Minnesota-Centric region are shown in Figure 7-4 for the different scenarios. (Note, the net loads for scenarios 1a and 2a are essentially unchanged from scenarios 1 and 2 and are not shown here.) The areas between the curves represents the impact of the increasing renewable energy penetrations. The addition of over 11,000 MW of renewable capacity from the Baseline Scenario to Scenario 2 reduced the peak net load by less than 800 MW while the minimum load was reduced by over 3,500 MW. The entire fleet of almost 23,000 MW of renewable capacity reduced the net peak load by about 3,000 MW while the minimum load was reduced by slightly more than 11,000 MW.

[1] Net load is calculated as hourly load energy minus wind and solar generation

It is this fact that makes the cycling capability and minimum stable operating points of the conventional generation critical factors in the analysis.

The timing of the renewable energy is also reflected in Figure 7-5, which shows the annual duration curves of the net energy imports for the Minnesota-Centric region. The overall region is initially a net importer for the year but the increasing amounts of renewable energy shifts it to a net exporter. However, it can be seen that there is little change in the peak imports while the maximum exports increase from a little over 3,500 MW to 6,650 MW.

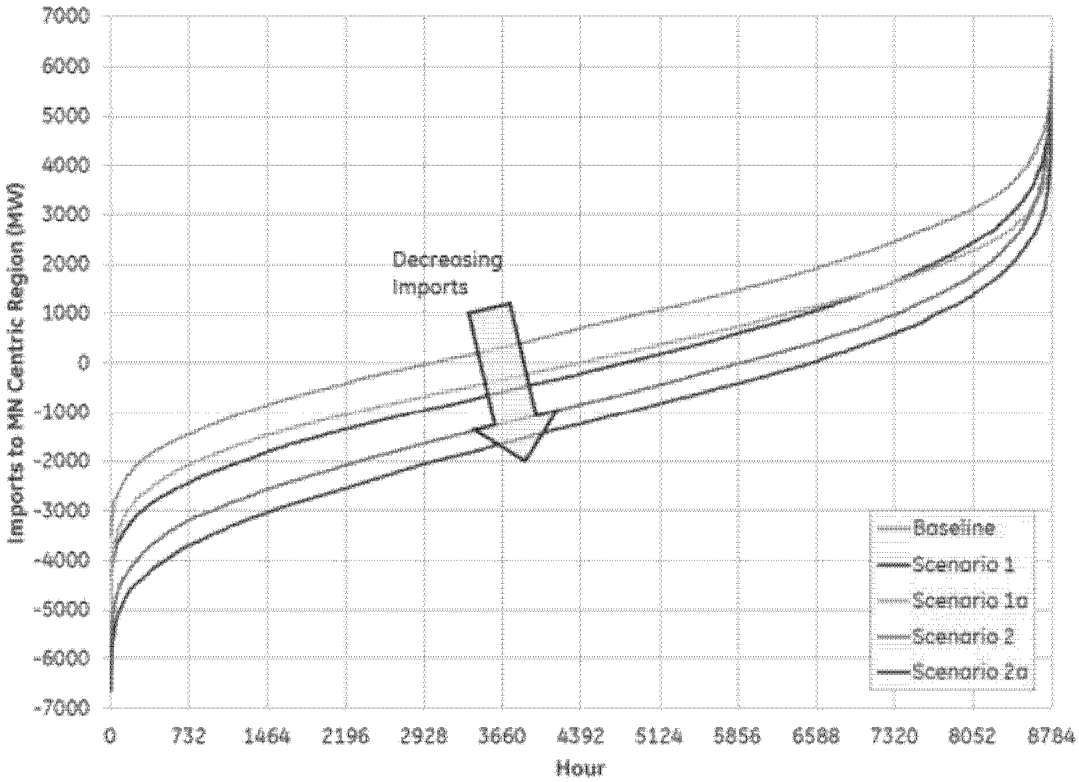

Figure 7-5 Annual Duration Curves of Energy Imports for Minnesota-Centric Region

7.2.1 Aggregate Wind and Solar Plant Capacity and Power Output

The dashed curves in Figure 7-6 show duration curves of the aggregate wind energy from all wind plants in the Minnesota-Centric region. Comparing the curves for the three scenarios shows the increase in wind energy from the Baseline to Scenario 1 to Scenario 2. The solid lines are duration curves of the aggregate ratings of the wind plants on-line. If a wind plant has no power output, then it is considered to be off-line with its power converters idle. If a wind plant is producing power, then it is considered to be on-line and all of its wind turbines and power converters are in-service and connected to the power grid. The flat shapes of these curves indicate that nearly all of the wind plants are on-line for nearly all hours of the year. The importance of this observation is discussed further in Section 7.7.1 (% non-synchronous generation and its impact on relative system strength).

Figure 7-7 is a similar plot for PV solar plants. The solid curves showing aggregate capacity on-line are essentially flat at full fleet rating for the daytime hours and flat at zero for nighttime hours.

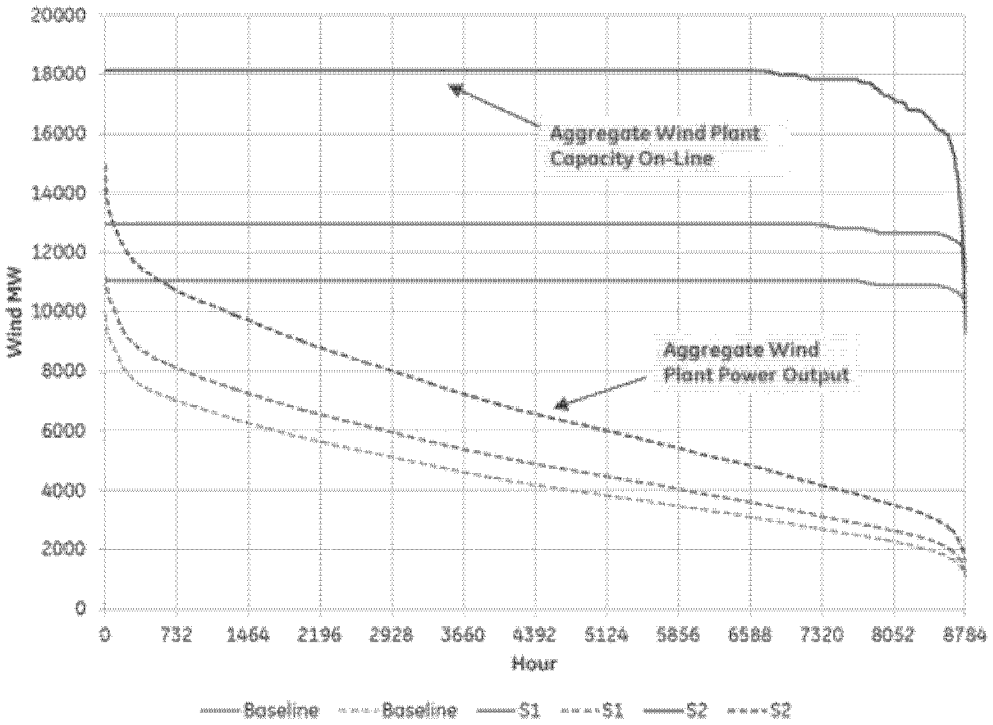

Figure 7-6 Duration Curves of Aggregate Wind Plant Capacity On-Line and Aggregate Wind Plant Power Output for Minnesota-Centric Region

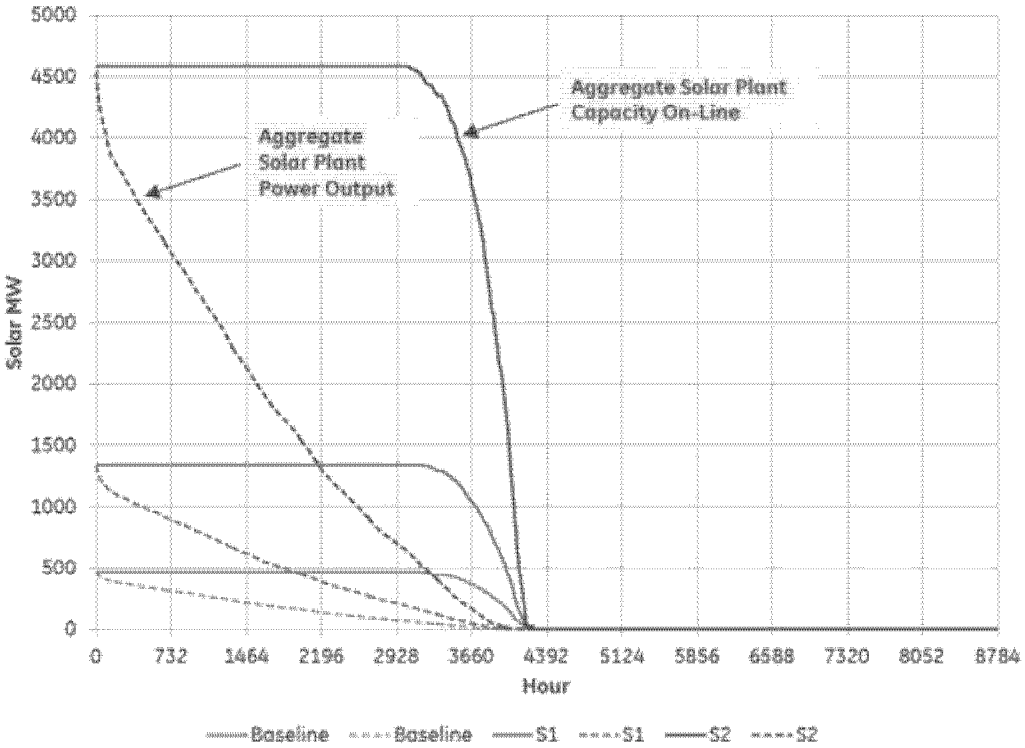

Figure 7-7 Duration Curves of Aggregate Solar Plant Capacity On-Line and Aggregate Solar Plant Power Output for Minnesota-Centric Region

Comparisons of Generation Fleet Utilization for Study ScenariosTable 7-4 gives a more detailed breakdown of the commitment and dispatch by generation type for Scenarios 1 and 1a. As explained earlier, the "MWh Committed" reflects the entire rating of the plants whenever they are on line while the "MWh Dispatched" only reflects the actual energy output. The column "CF" is the capacity factor, which is the energy output divided by the capacity of the fleet times 8784 hours in the year. The next column, "Online CF", is the average capacity factor over just those hours when the units are on. The clearest example of these terms is with the Combined Cycle units (CC). While the overall capacity factor only change slightly between the two scenarios, from 15% to 16%, the online CF, or average operating level, increased from 59% to 74% reflecting a much more efficient level of operation when the coal plants are permitted to cycle. Note, only units that operated at some time during the year were counted in the fleet, so the capacities could change slightly between scenarios.Table 7-5 shows a similar comparison for Scenarios 2 and 2a. Allowing the coal plants to cycle reduced their average capacity factors from 69% to only 58% but their average level of operation increased from 76% to 85%. The combined cycle units also increased the overall efficiency of their operation.

Table 7-4 Comparison of Minnesota-Centric Generation Fleet Utilization Scenarios 1 and 1a

	S1				S1a					
Unit Type	Total MWh Committed	Total MWh Dispatched	CF	Online CF	Total MWh Committed	Total MWh Dispatched	CF	Online CF	Δ (S1a-S1)	% Change in Dispatch
Wind	113,516,032	45,298,460	40%	40%	112,894,006	45,025,066	40%	40%	(273,394)	-1%
ST Coal	76,285,799	69,984,409	65%	92%	75,904,870	70,043,841	65%	92%	59,432	0%
CT Gas	428,220	187,010	0%	44%	2,281,544	1,503,340	2%	66%	1,316,330	704%
CC	8,478,103	5,024,030	15%	59%	7,134,913	5,266,709	16%	74%	242,680	5%
Nuclear	20,209,392	20,036,836	96%	99%	19,414,416	19,246,693	93%	99%	(790,143)	-4%
Solar PV	5,175,211	2,002,869	15%	39%	5,164,167	1,998,268	15%	39%	(4,600)	0%
Conventional Hydro	1,817,899	1,225,371	30%	67%	4,110,912	1,606,155	39%	39%	380,784	31%
ST Renewable	3,965,527	3,952,032	99%	100%	2,808,218	2,783,508	70%	99%	(1,168,524)	-30%
ST Gas	184,918	82,764	6%	45%	173,067	78,786	6%	46%	(3,978)	-5%
ST Other	641,604	635,462	92%	99%	614,174	607,706	88%	99%	(27,756)	0%
IC Renewable	226,844	226,138	100%	100%	158,898	157,210	69%	99%	(68,929)	-31%
IC Gas	2,826	1,742	1%	62%	2,443	1,975	2%	81%	233	13%
Grand Total	*230,932,414*	*148,657,123*	-	-	*230,662,037*	*148,319,353*	-	-	*(337,770)*	*0%*

Table 7-5 Comparison of Minnesota-Centric Generation Fleet Utilization Scenarios 2 and 2a

	S2				S2a					
Unit Type	Total MWh Committed	Total MWh Dispatched	CF	Online CF	Total MWh Committed	Total MWh Dispatched	CF	Online CF	Δ (S2a-S2)	% Change in Dispatch
Wind	157,339,652	60,467,557	38%	38%	157,943,346	60,799,827	38%	38%	332,270	1%
ST Coal	75,987,045	57,743,667	69%	76%	72,743,109	62,072,265	58%	85%	4,328,598	8%
CT Gas	388,393	175,805	0%	45%	1,241,682	867,191	1%	70%	691,387	393%
Solar PV	17,666,794	6,841,300	17%	39%	17,694,013	6,853,504	17%	39%	12,203	0%
CC	5,375,617	3,052,716	11%	57%	4,823,291	3,344,478	10%	69%	291,762	10%
Nuclear	20,207,026	20,036,836	96%	99%	19,414,416	19,246,693	93%	99%	(790,143)	-4%
Conventional Hydro	4,110,444	1,606,234	39%	39%	4,110,912	1,606,218	39%	39%	(16)	0%
ST Renewable	3,974,220	3,715,592	93%	93%	2,808,218	2,708,547	68%	96%	(1,007,045)	-27%
ST Gas	184,170	82,437	6%	45%	172,413	77,529	6%	45%	(4,908)	-6%
ST Other	641,526	632,029	92%	99%	614,174	606,931	88%	99%	(25,098)	-4%
IC Renewable	227,041	212,182	93%	93%	158,898	153,244	67%	96%	(58,938)	-28%
IC Gas	2,068	1,215	1%	59%	1,534	1,177	1%	77%	(38)	-3%
Grand Total	*286,103,995*	*154,567,570*	-	-	*281,727,049*	*158,338,290*	-	-	*3,770,720*	*2%*

7.3 Wind and Solar Curtailment

Curtailment of wind or solar generation occurs when the system is not able to accommodate all of the wind and solar generation in a given hour. The two most common reasons for curtailment are:

- The available power at particular wind or solar plant (or group of plants) is higher than the capacity of transmission lines transmitting the power to the bulk grid. This is often referred to as "local congestion". Given that the system operates with security-constrained economic dispatch, the limitation could reflect an N-1 and/or a prior outage condition.
- The aggregate wind and solar power generation over a wide area exceeds what the grid can accommodate, even after all committed conventional power plants are dispatched at their minimum power levels and regional exports are maximized. This is sometimes referred to as a "minimum generation" condition.

In general, a small amount of curtailment is to be expected in any system with a significant level of wind and solar generation. There will be occasional operating conditions where it is economically efficient to accept a small amount of curtailment (i.e., where mitigation of that curtailment would be disproportionately expensive and not justifiable).

Table 7-6 shows annual curtailment of wind and solar energy as a percentage of the total available wind and solar energy. In all scenarios the level of curtailment in the Minnesota-Centric region is relatively small. Figure 7-8 shows annual duration curves of hourly solar curtailment. An inset in the figure shows an expanded view of the hours with the most curtailment. Curtailment occurs for only a very few hours of the year. Scenario 2 has the most curtailment of solar energy; more than 800 MW is curtailed during the worst hour. Further investigation of curtailment by plant revealed that the majority of all solar energy curtailment in Scenario 2 occurred in only two specific plants, indicating that it is likely caused by local congestion. Nonetheless, only 3% of total available solar energy is curtailed in these plants.

Figure 7-9 shows annual duration curves of hourly wind curtailment. In the Baseline and Scenario 1, there are a few hours where wind curtailment approaches 1000 MW. But for the rest of the year, curtailment is very low. In Scenario 2, there are several hours where wind curtailment exceeds 3000 MW. Figure 7-10 shows total curtailed wind energy by hour of day. In all scenarios, there is higher curtailment in nighttime hours (when many baseload generators are dispatched to their minimum output levels) than in daytime or evening hours. The trend most prominent in Scenario 2. This suggests that a portion of the overall curtailment is likely due to system-wide minimum generation conditions. This type of curtailment could be reduced by decommitting some baseload generation via economic market signals. The effectiveness of this mitigation option is illustrated by comparing Scenario 2 (coal units must-run) with Scenario 2a (economic coal commitment). Wind curtailment decreases from 2.14% to 1.60% (a reduction of 332 GWh).

Figure 7-10 also illustrates that there is some wind curtailment during daytime and evening hours, when conventional generation could likely be dispatched down if needed. This suggests that a portion of the wind curtailment is due to local transmission congestion at wind plants. In fact, further investigation revealed that the majority of wind curtailment in the Baseline and Scenario 1 occurred in just a few wind plants. This cause for curtailment could be mitigated by transmission modifications, if economically justifiable.

Table 7-6 Annual Wind and Solar Energy Curtailment

	Baseline	Scenario 1	Scenario 1a	Scenario 2	Scenario 2a
Wind Curtailment	0.42%	1.00%	1.59%	2.14%	1.60%
Solar Curtailment	0.09%	0.00%	0.23%	0.42%	0.24%

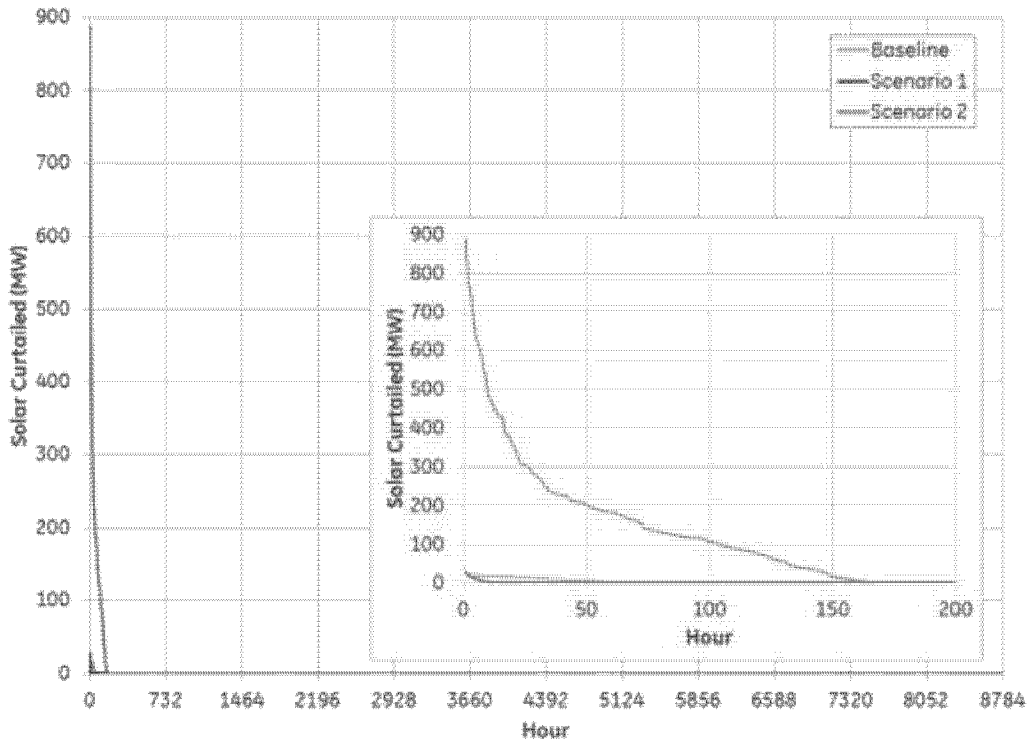

Figure 7-8 Annual Duration Curves of Solar Curtailment for Minnesota-Centric Region

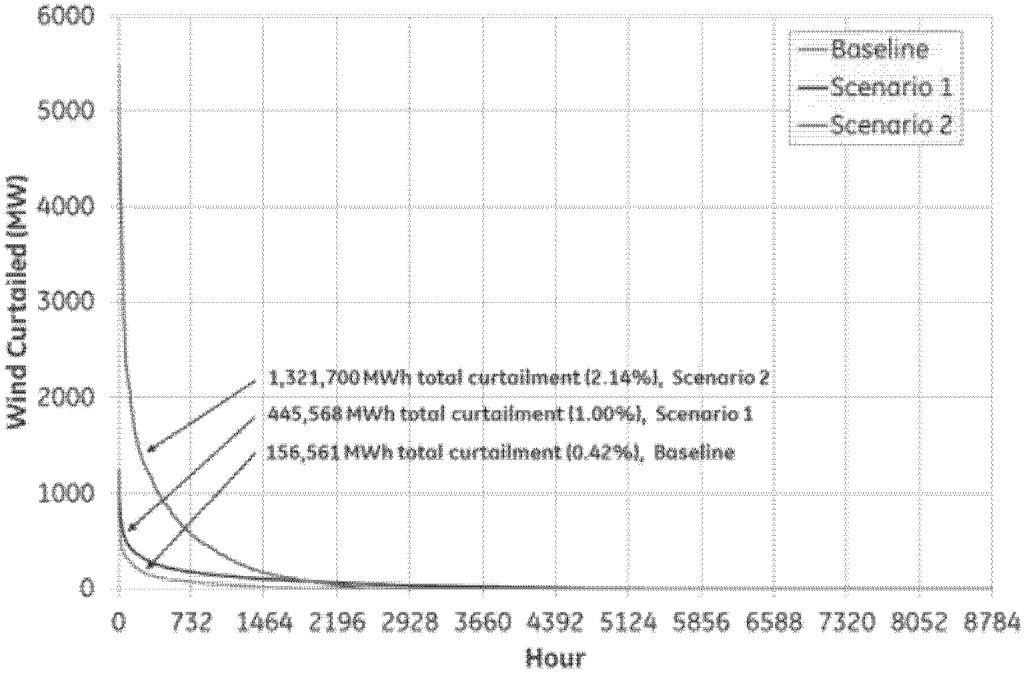

Figure 7-9 Annual Duration Curves of Wind Curtailment for Minnesota-Centric Region

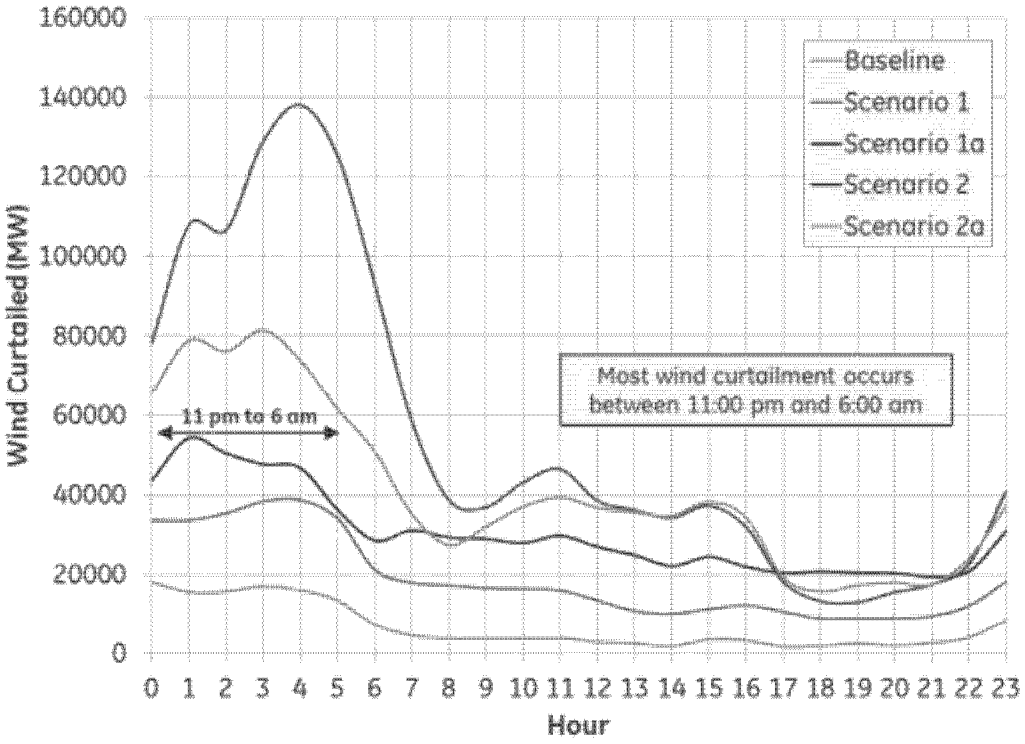

Figure 7-10 Wind Curtailment by Hour of Day for Minnesota-Centric Region

7.4 Thermal Plant Cycling

7.4.1 Coal Units

Shutting down and then restarting generating units is called "cycling". Increased cycling of conventional generation is a natural side effect of increased wind and solar generation. Some conventional generators are shut down during periods of high wind and solar energy production, and then restarted afterwards.

Some types of units are designed to withstand multiple shutdown/startup cycles (eg., combustion turbines, hydro generators, combined cycle units). However, most coal plants were originally designed for baseload operation; that is, they were intended to operate continuously with only a few start/stop cycles in a year (mostly due to scheduled or forced outages). Increased cycling duty could impact wear and tear on these units, with corresponding impacts on maintenance requirements.

Many coal plants in MISO presently are designated by the plant's owner to operate as "must-run" to avoid start/stop cycles that would occur if they were economically committed by the market. Figure 7-11 through Figure 7-15 illustrate the amount of cycling for coal plants in the Minnesota-Centric region.

- Figure 7-11 shows total annual starts plotted as a function of unit rating for Baseline, Scenario 1 and Scenario 2. In these scenarios, all but three coal units were assumed to be must-run, consistent with existing operating practices for those units. Hence, those units show only one start per year, following a scheduled maintenance period. The three economically committed coal units experienced from 50 to 230 starts per year.
- Figure 7-12 shows total annual starts for Scenarios 1 (with must-run assumption) and Scenario 1a (with economic commitment and forced outages). In Scenario 1a, coal units experience significantly more cycling duty than in Scenario 1. The plot also shows a general trend where smaller coal units have more annual starts than larger units.
- Figure 7-13 shows a similar comparison for Scenarios 2 and 2a. The trends are similar to the pervious figure.
- Figure 7-14 shows a comparison of total annual starts for Scenarios 1a and 2a. In both scenarios, the coal unit modeling assumptions are the same (economic commitment, forced outages). The only difference is that Scenario 2a has higher wind and solar penetration than Scenario 1a. The plot shows that nearly all coal units experience higher cycling duty when the penetration of wind and solar energy increases.
- The previous figures showed total annual starts due to scheduled outages, forced outages, and economic commitment. Figure 7-15 shows only "operational" starts due to economic commitment. This figure enables a direct comparison of how increased wind and solar penetration affects the cycling duty if the coal units are economically committed by the energy market. Cycling duty increases significantly on nearly all coal units.

Note on Coal Plant Modeling: In this study, coal plants were modeled using data that was derived from the publically available Ventyx dataset, and further vetted by MISO for use in their production simulation analysis studies. Data affecting plant cycling (minimum down time, startup time, startup cost, etc) are representative values for the types of plants modeled. A more thorough analysis of coal plant cycling performance would require use of proprietary plant specific data for individual coal units, which was beyond the scope of this study.

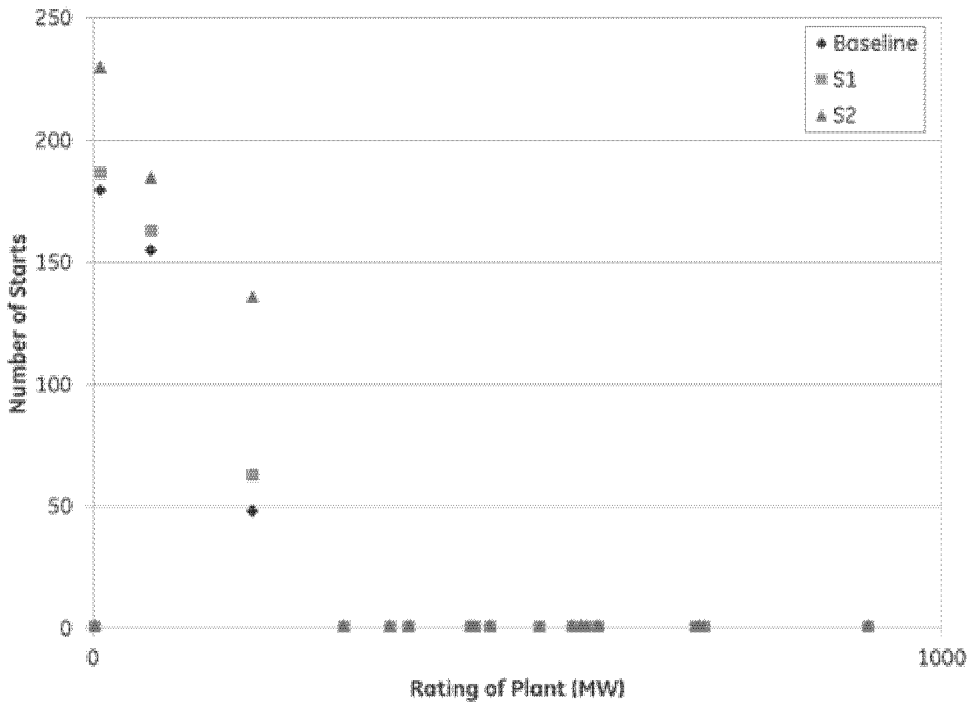

Figure 7-11 Coal Unit Total Annual Starts for Baseline, Scenario 1 and Scenario 2

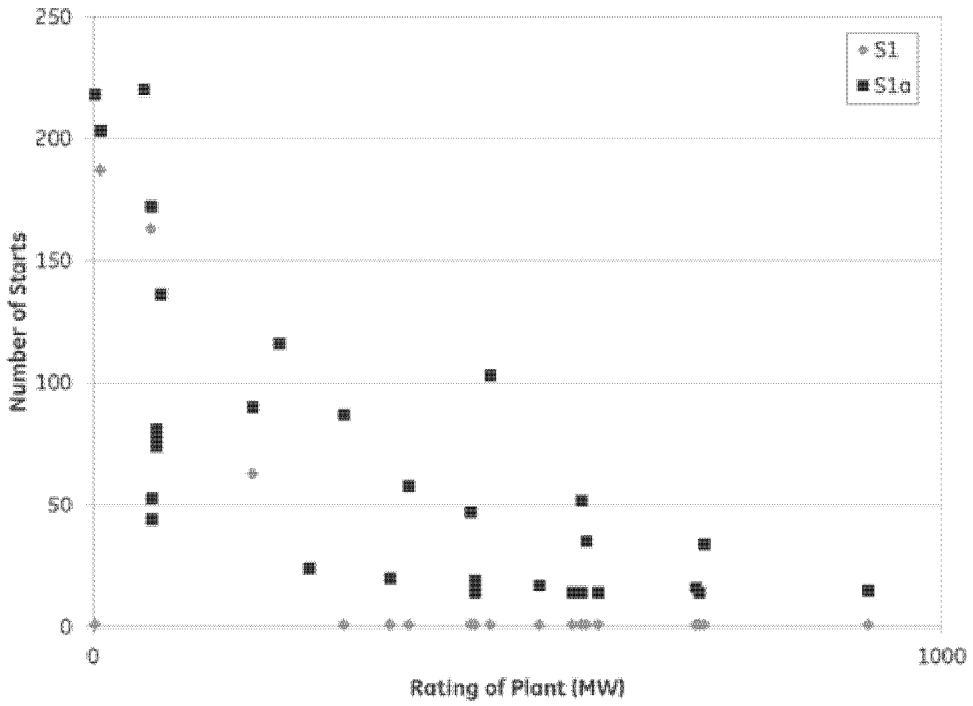

Figure 7-12 Coal Unit Total Annual Starts for Scenario 1 and Scenario 1a

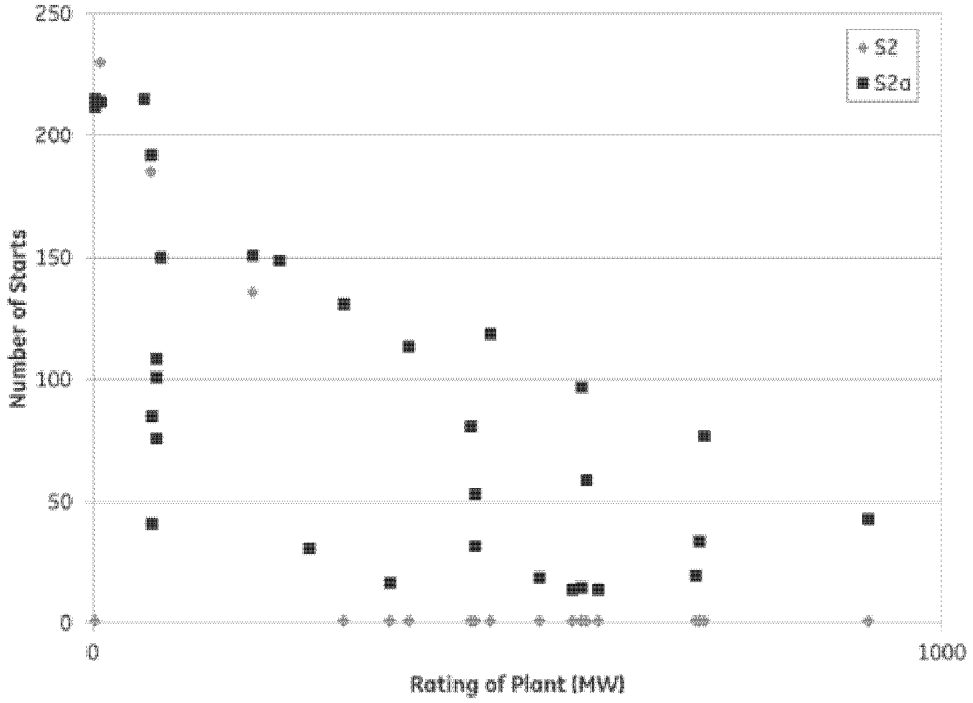

Figure 7-13 Coal Unit Total Annual Starts for Scenario 2 and Scenario 2a

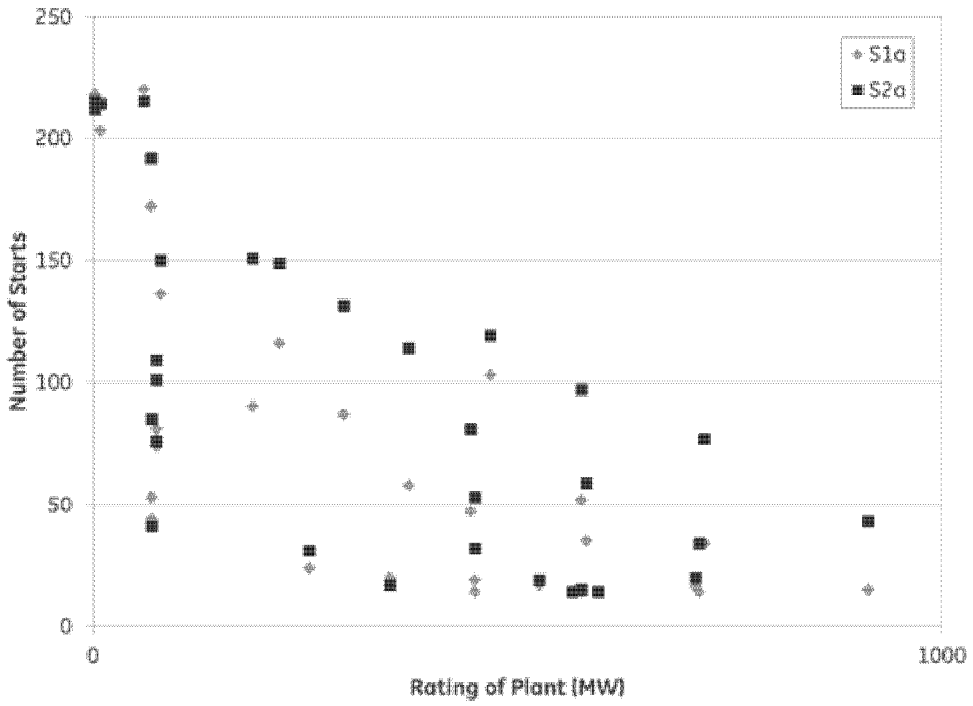

Figure 7-14 Coal Unit Total Annual Starts for Scenario 1a and Scenario 2a

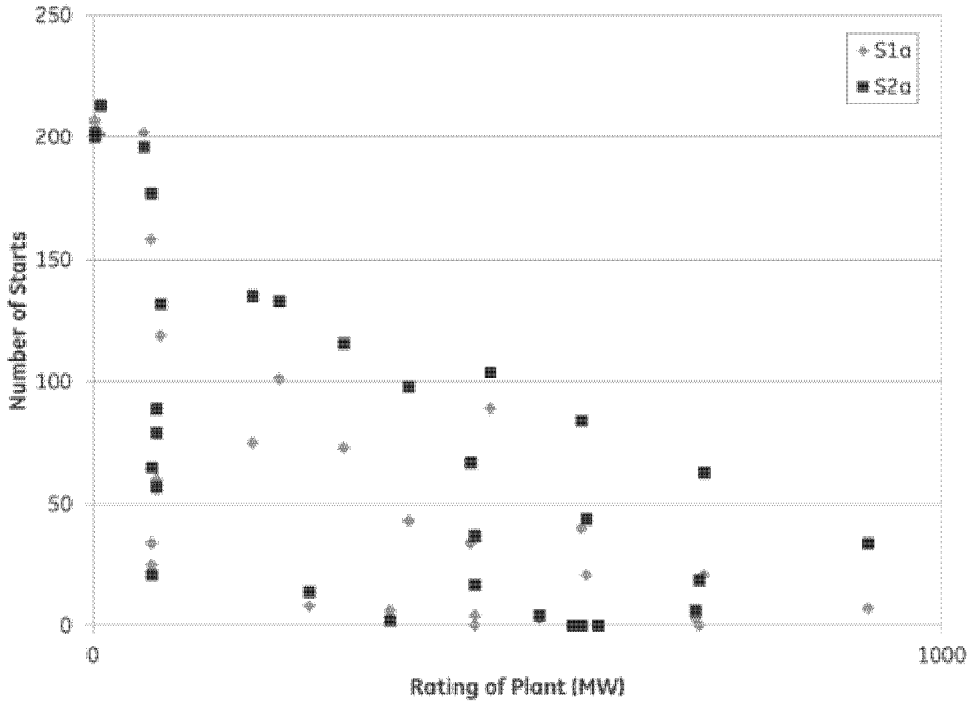

Figure 7-15 Coal Unit Annual "Operational" Starts due to Economic Commitment for Scenario 1a and Scenario 2a

7.4.2 Combined-Cycle Units

Combined-cycle (CC) units are better able to accommodate cycling duties than coal plants. Figure 7-16 is a plot of annual CC unit starts for all 5 scenarios. The data shows that some CC units in the Minnesota-Centric region experience as many as 200 start/stop cycles per year, while other units experience only a few cycles per year. In general, cycling of CC units declines slightly as wind and solar penetration increases. This decline is primarily due to a decrease in CC plant utilization as wind and solar energy increases.

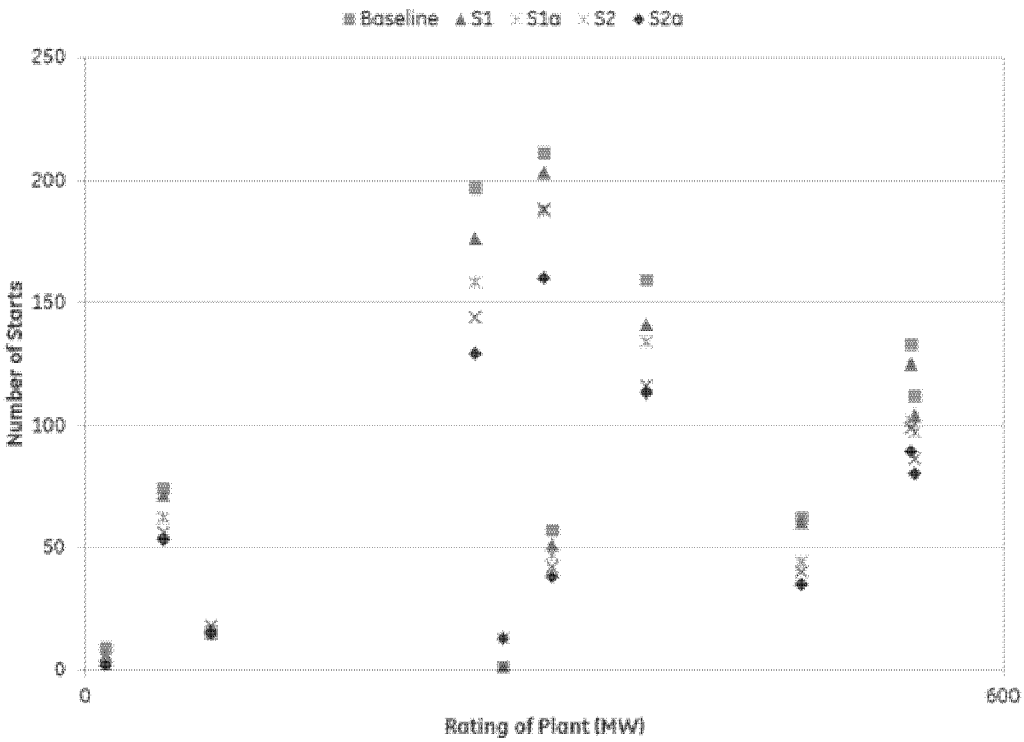

Figure 7-16 Combined-Cycle Unit Total Annual Starts for Baseline, Scenario 1, Scenario 1a, Scenario 2 and Scenario 2a

7.5 MISO Ramp-Range and Ramp-Rate Capability

Ramp-range and ramp-rate capabilities of a balancing area's conventional generation fleet are measures of its ability to accommodate the variability and uncertainty associated with wind and solar generation (i.e., the fleet's ability to follow changes in wind plant output or to compensate for forecast errors in system load and wind/solar energy production. This analysis was conducted for all of MISO Central-North, since this capability is only relevant for a balancing area.

Figure 7-17 shows range-up capability for the MISO conventional generation fleet for the Baseline, Scenario 1 and Scenario 2. Figure 7-18 shows ramp-rate up capability for the same scenarios. Ramp-range-up and ramp-rate-up capability of the MISO conventional generation fleet increases with increased penetration of wind and solar generation. Conventional generation is generally dispatched down rather than decommitted when wind and solar energy is available, which gives those generators more headroom for ramping up if needed.

Figure 7-19 shows range-down capability for the MISO conventional generation fleet for the Baseline, Scenario 1 and Scenario 2. Figure 7-20 shows ramp-rate down capability for the same scenarios. Ramp-range-down and ramp-rate-down capability of the MISO conventional generation fleet decreases with increased penetration of wind and solar generation. In Scenario 2, there are 500 hours when ramp-rate-down capability of the conventional generation fleet falls below 100 MW/min. As shown in Figure 7-21, periods of low ramp-down capability coincide with periods of high wind and solar generation (see regions within red boxes). Wind and solar generators are capable of providing additional ramp-down capability to MISO during these periods. MISO's existing Dispatchable Intermittent Resource (DIR) process already enables this for wind generators. It is anticipated that MISO would expand the DIR program to include solar plants in the future.

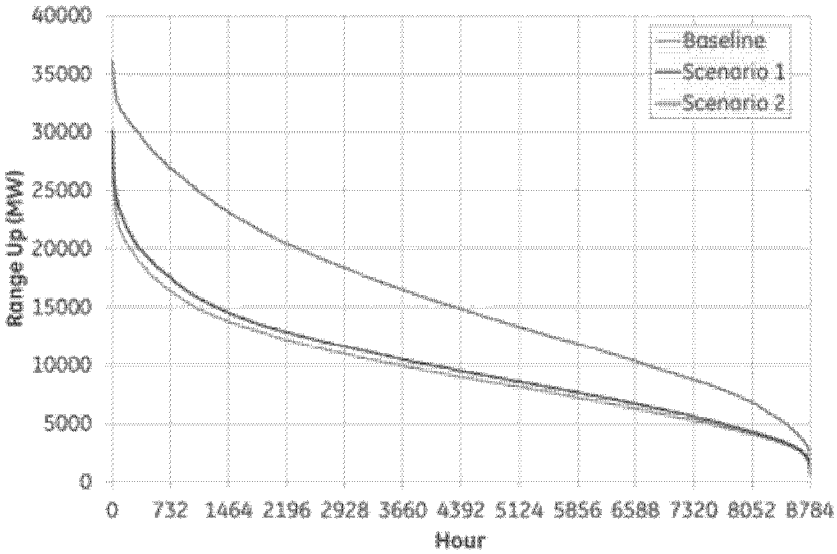

Figure 7-17 Annual Duration Curve of Range-Up Capability for Conventional Generation within MISO Central-North

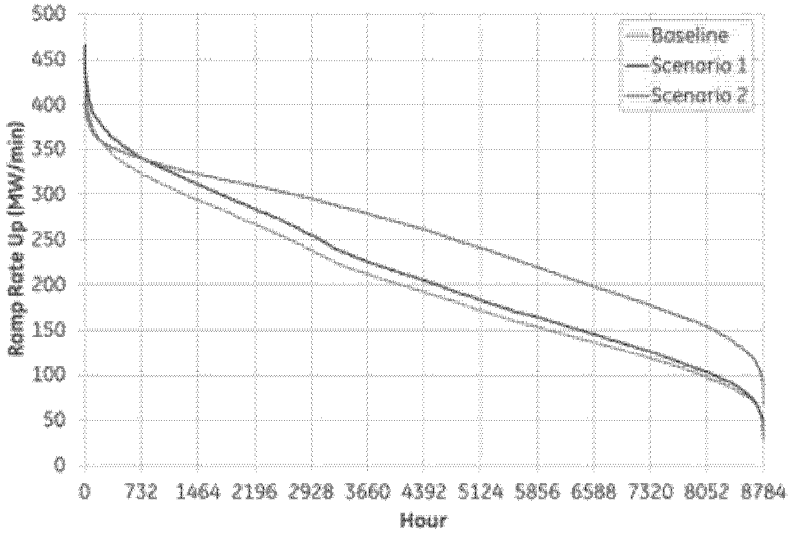

Figure 7-18 Annual Duration Curve of Ramp-Rate-Up Capability for Conventional Generation within MISO Central-North

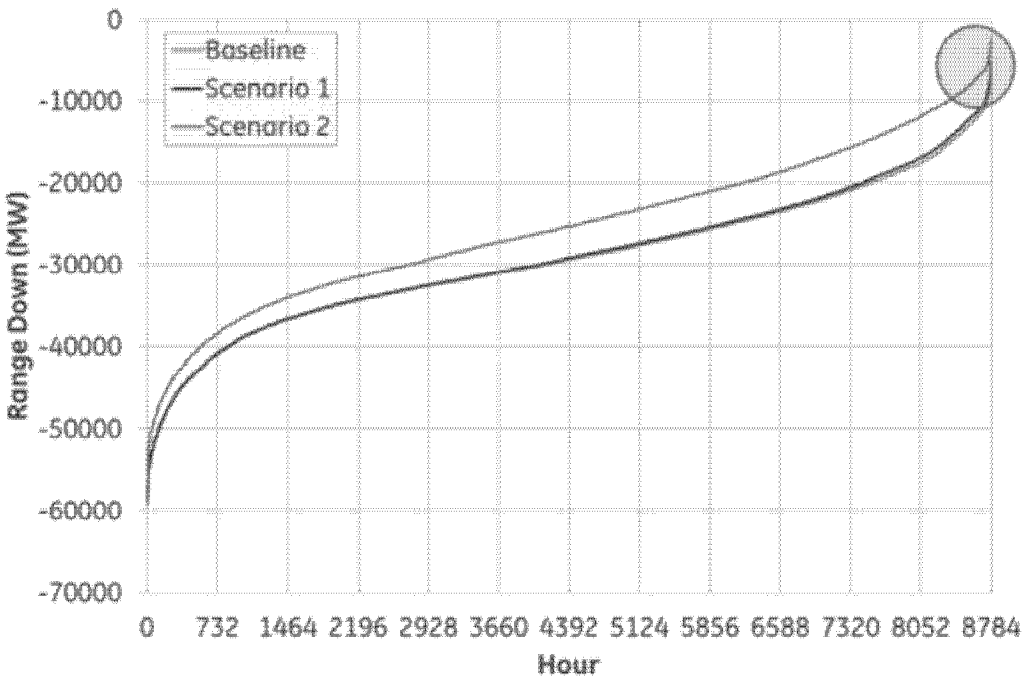

Figure 7-19 Annual Duration Curve of Range-Down Capability for Conventional Generation within MISO Central-North

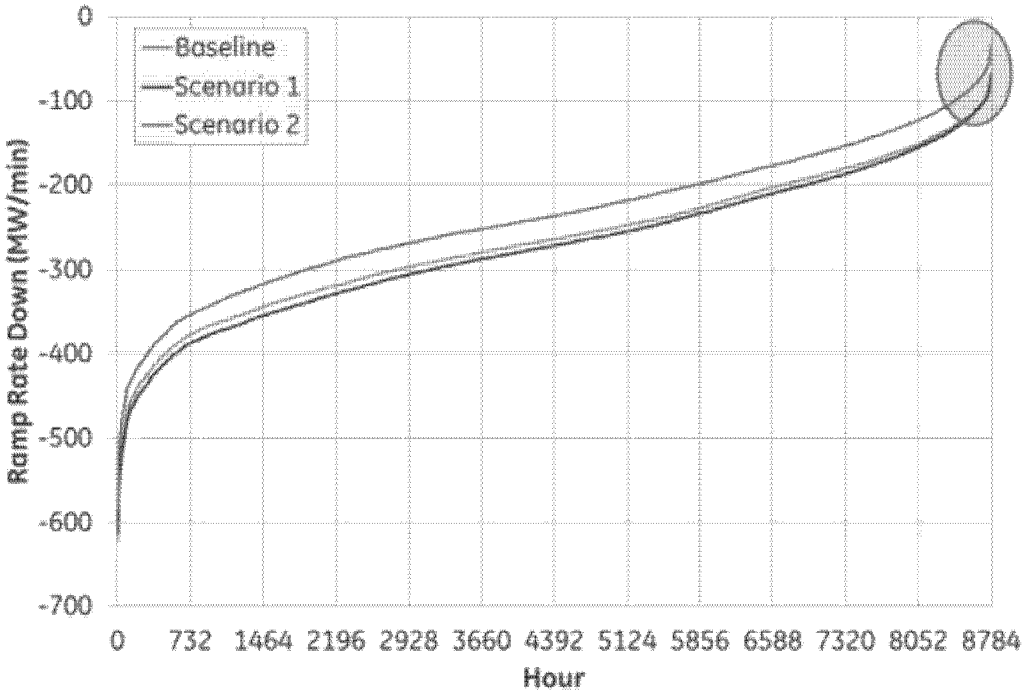

Figure 7-20 Annual Duration Curve of Ramp-Rate-Down Capability for Conventional Generation within MISO Central-North

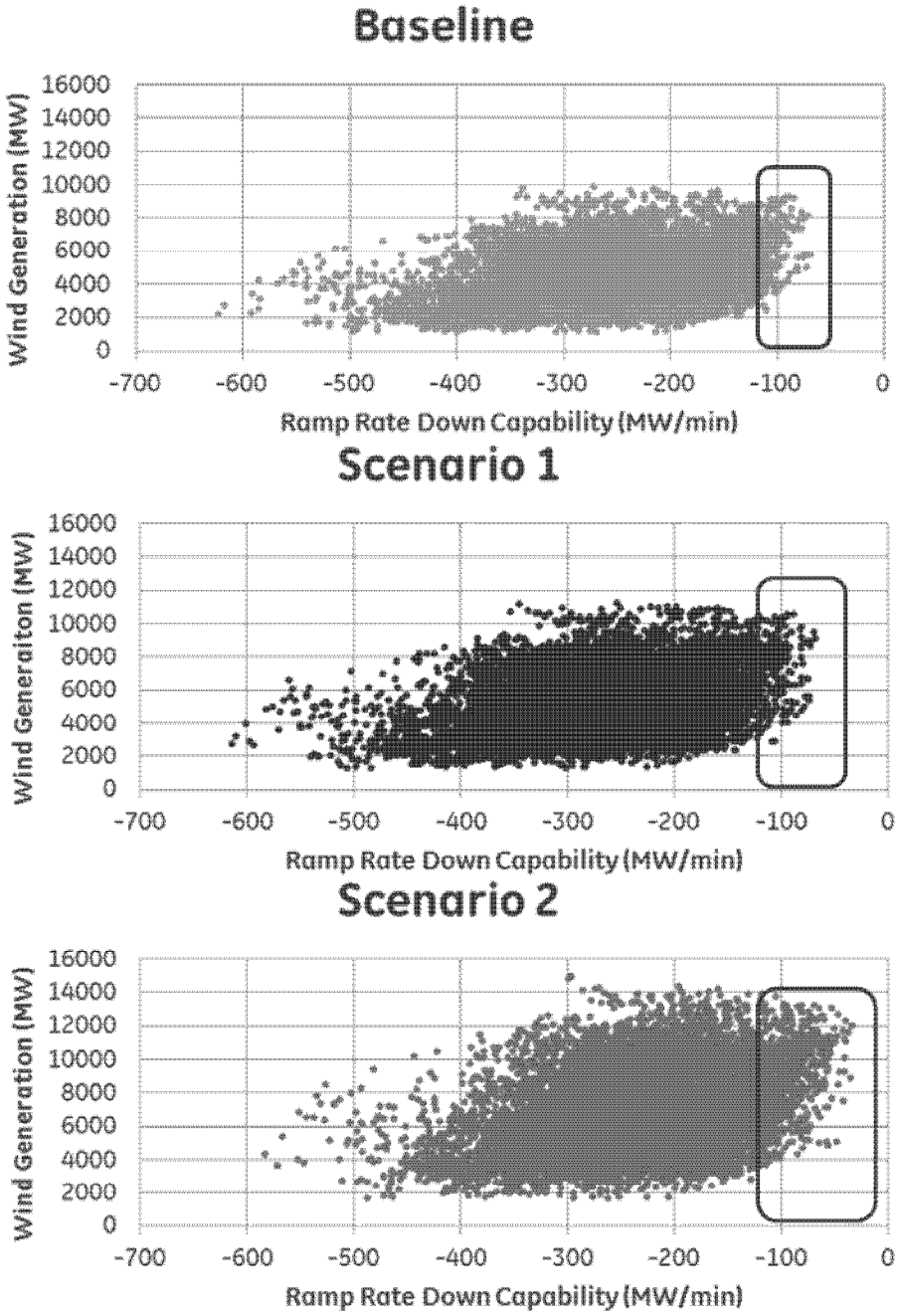

Figure 7-21 Scatter Plot of Ramp-Rate Down Capability of MISO Conventional Generation Fleet vs Wind Generation in Minnesota-Centric Region

7.6 Carbon Emissions

Table 7-7 shows total annual carbon emissions for the study scenarios. Overall, the CO_2 emissions are closely related to the amount of ST Coal committed in the system. Scenario 1a has nine more coal plants than Scenario 1. As a result, Scenario 1a has a higher level of CO_2 emissions. Similarly, Scenario 2a has higher CO_2 than Scenario 2 because of the nine additional coal plants.

Table 7-7 CO_2 Emissions for the Minnesota-Centric Region

	Baseline	S1	S1a	S2	S2a
Tons of CO2	83,627,254	82,055,702	84,027,816	67,882,045	73,991,430
Reduction Versus Baseline (Tons CO2)		1,571,551	(400,562)	15,745,209	9,635,823

7.7 Screening Metrics for Stability/Control Issues

The results of the production simulation analysis were screened to select challenging operating conditions for dynamic performance, and these operating points were subsequently analyzed with fault simulations in the dynamics task. This section describes the three screening metrics and the process for selecting specific system operating conditions for dynamic simulation analysis.

7.7.1 Percent Non-Synchronous Generation (% NS)

In order to assess the stability of the power system, focusing only on generation owned by the Minnesota utilities was no longer sufficient. To evaluate stability issues, it is necessary to consider all generation located within the geographic area of interest. Thus, for this metric, the definition of the Minnesota-Centric region was modified to include all generation, regardless of owner or type, within the regions shown in Figure 7-22. The Minnesota-Centric region for calculating % non-synchronous (NS) is defined by the shaded area of the figure, and includes six sub-regions; Northern Minnesota, South and Central Minnesota, Southwest Minnesota, North Dakota, South Dakota and Iowa. Based on the physical location of the generation, the % NS metric was calculated for the Minnesota-Centric region and the six sub-regions.

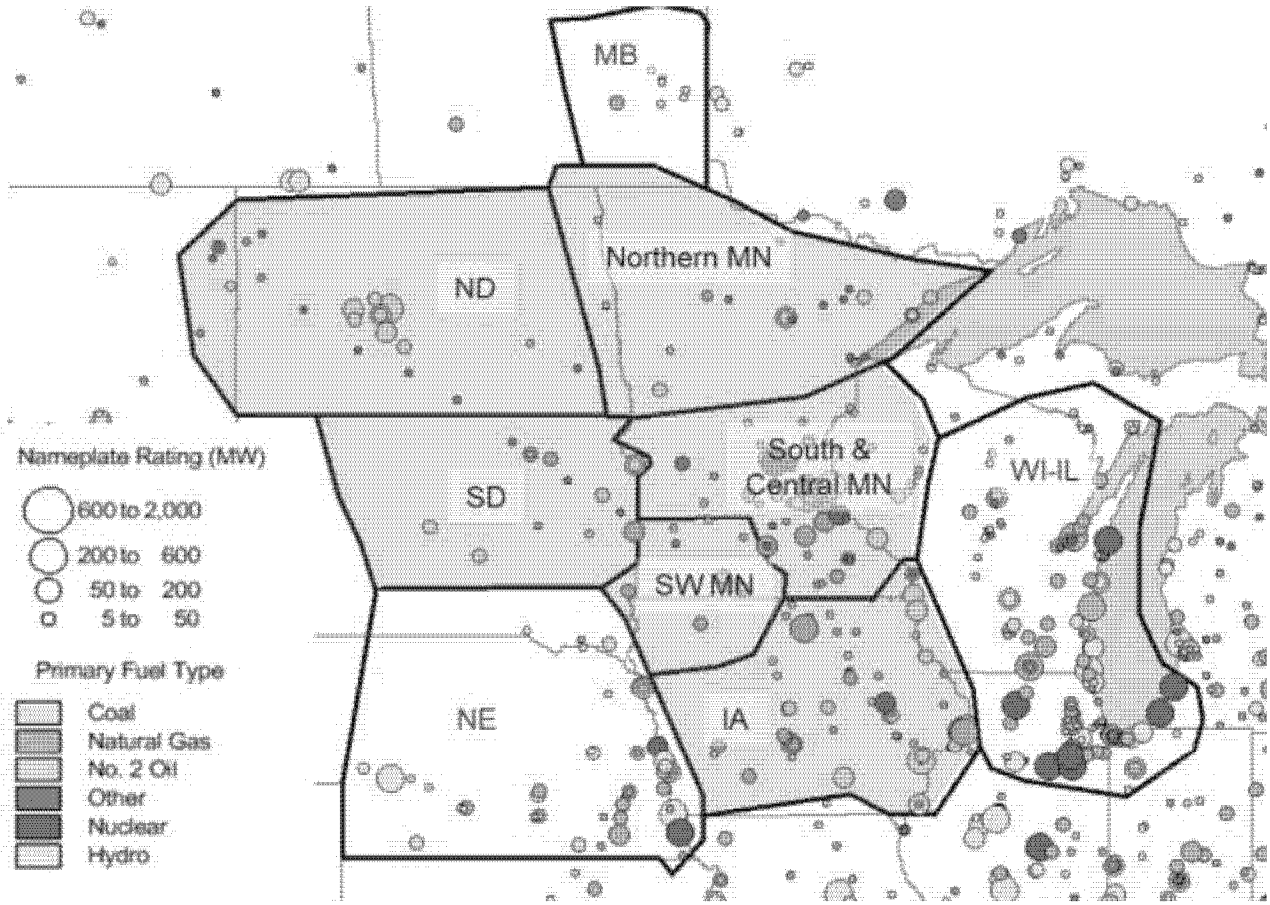

Figure 7-22 Geographic Footprint of Minnesota-Centric Region for % NS Metric

The % NS metric is the ratio of non-synchronous inverter-based generation (i.e. wind and solar) MW rating to the total generation (i.e. wind, solar and all conventional generation) MW rating within a given geographic boundary.

$$\%\,NS = \frac{Total\ online\ wind + solar\ MW\ rating}{Total\ online\ generation\ MW\ rating}$$

This metric is an indicator of ac system strength or weakness. Synchronous generators are pure voltage sources and therefore contribute short-circuit current and support the "strength" of the ac transmission system. Inverter-based generators do not contribute to system strength. Inverter-based generators depend on the system strength provided by synchronous machines (either generators or synchronous condensers) to operate in a stable manner. Low % NS indicates strong system conditions and high % NS indicates potentially weak system conditions. Hence, this metric can be used to identify periods of weak system conditions for further evaluation using dynamic analysis methods.

HVDC converters are also affected by system strength in a similar manner. HVDC converters have similar internal controls that can experience degraded stability under weak system conditions. However, given the scope of this study, the analysis reported here only considers weak system issues related to wind and solar generation.

7.7.2 Percent Renewable Penetration (% RE)

The % RE metric is the ratio of all wind and solar generation MW output to the total MW output of all generation (including wind and solar) within a given geographic boundary:

$$\%\,RE = \frac{Wind + Solar\ MW\ dispatched}{Total\ Generation\ MW\ dispatched}$$

This metric was applied to the Minnesota-Centric region as defined in Figure 7-1. The % RE metric was selected as it is one of the traditional metrics used to identify periods of the year where there are high levels of renewable generation supplying the load in the system, and where the dynamic performance of the overall system is more dependent on the dynamic performance of the wind and solar resources.

7.7.3 Transmission Interface Loading

This metric was used to identify periods of high loading on three interfaces that are important to the dynamic performance of the Minnesota region. High loading on these interfaces stresses the overall transmission system, and provides appropriate operating conditions for testing system resilience to transmission system faults.

North Dakota Export (NDEX): This interface consisted of 23 lines that provided most of the power transfer out of the North Dakota sub-region. The geographic representation of this interface is seen in Figure 7-23.

Figure 7-23 NDEX Transmission Interface

Buffalo Ridge Outlet: This interface consisted of four selected transmission lines that transfer energy out of the wind rich Buffalo Ridge region. The physical location of the lines is seen in Figure 7-24.

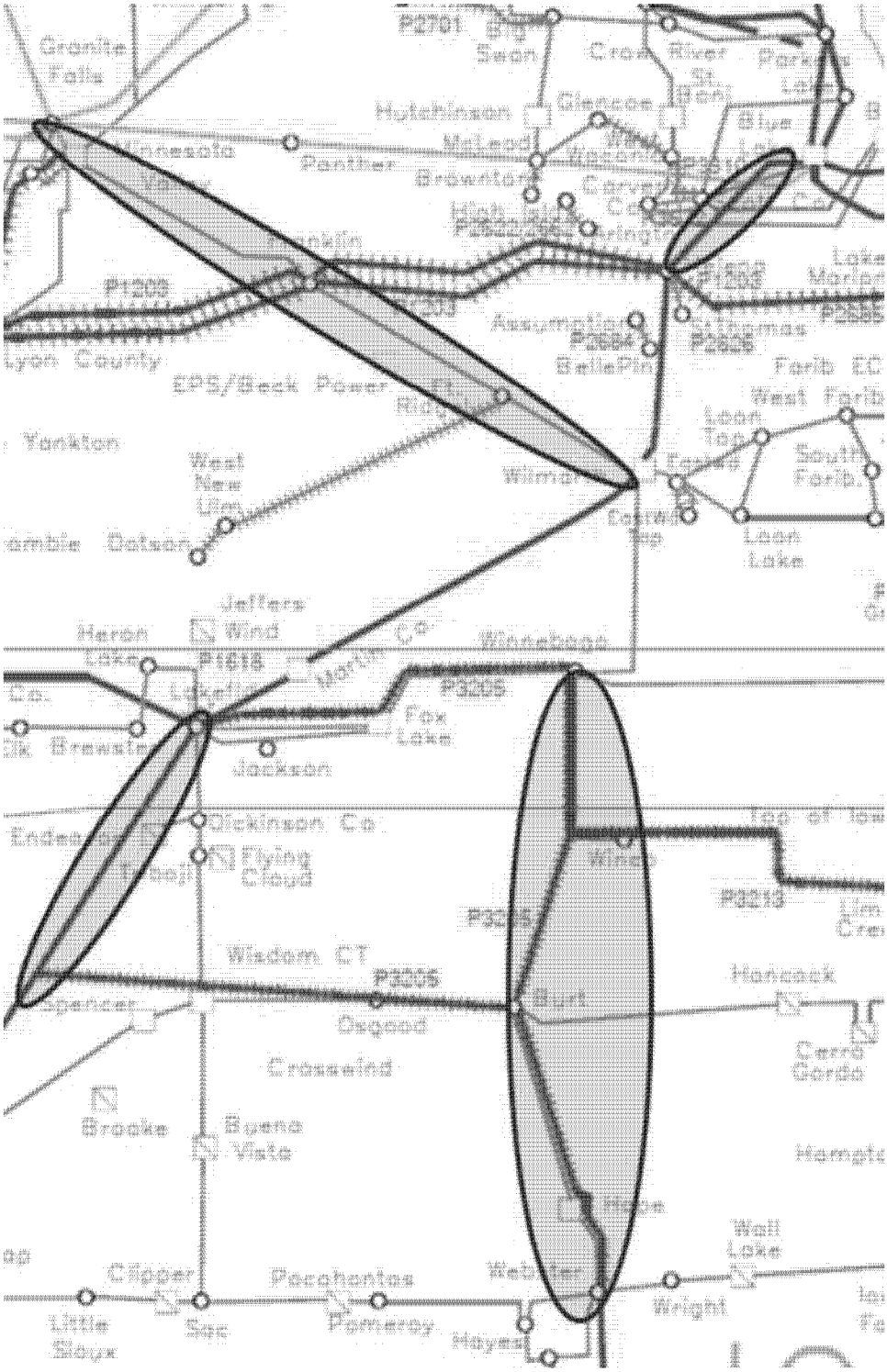

Figure 7-24 Buffalo Ridge Outlet Lines

Minnesota-Wisconsin Export (MWEX): This interface monitored the flows across three major transmission lines from Minnesota into Wisconsin(see Figure 7-25).

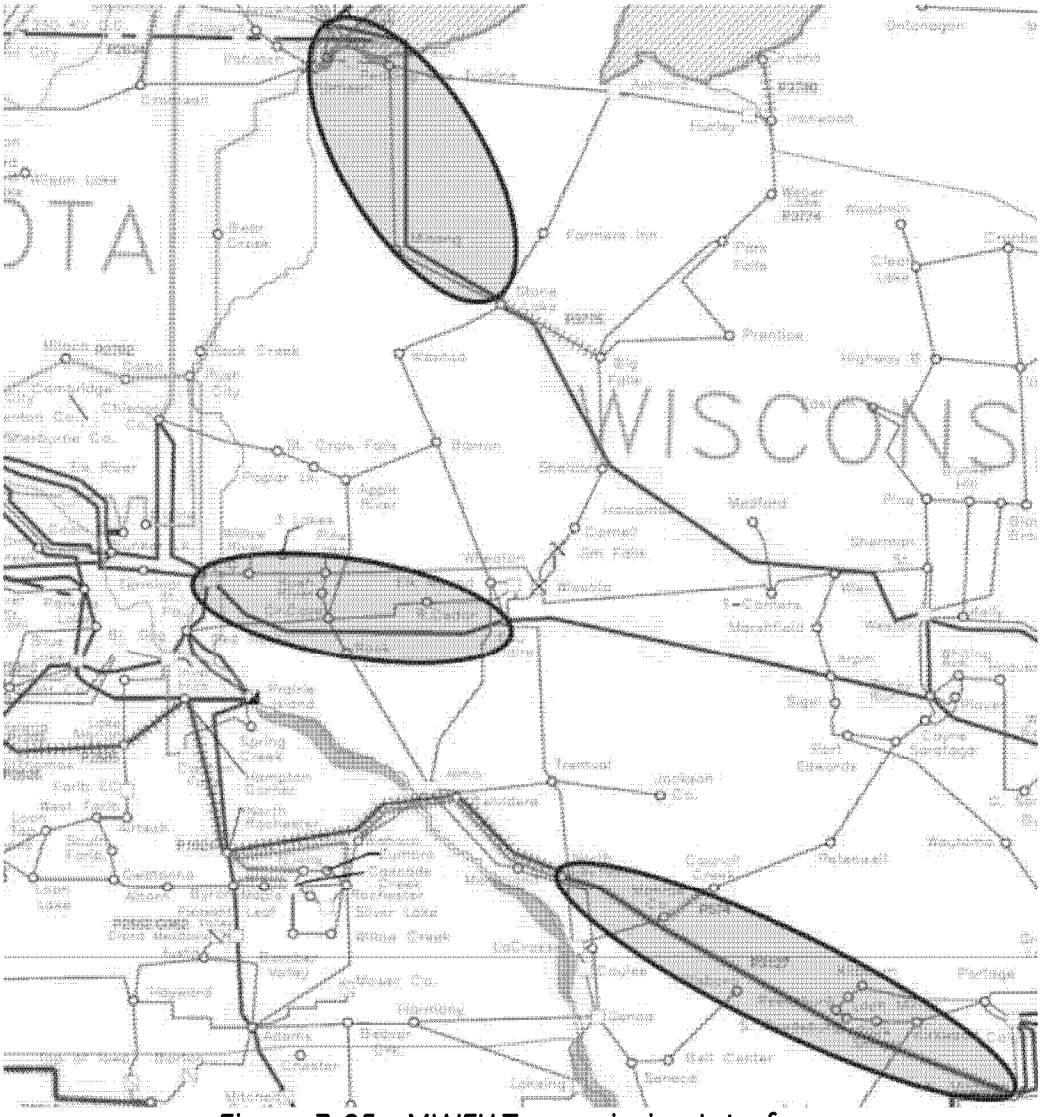

Figure 7-25 MWEX Transmission Interface

7.7.4 Analysis of Percent Non-Synchronous Generation

The % NS metric was calculated for each hour of the year and plotted as duration curves for the Minnesota-Centric region as well as its six subregions (per Figure 7-22). The results are plotted in Figure 7-26 through Figure 7-30.

The % NS varies greatly across the five scenarios. The general trend is that % NS gradually increases from the Baseline (Figure 7-26) to Scenario 1 (Figure 7-27) and finally to Scenario 2 (Figure 7-29). This correlates with the increased wind and solar generation displacing some of the conventional synchronous generation in the region. With lower levels of conventional plant online, the % NS values increase on average.

Different trends are observed when comparing Scenario 1 with Scenario 1a (Figure 7-28). In Scenario 1a, there were nine additional coal plants (existing plants not retired), all of the coal plants were given more operational flexibility (i.e., not must-run), and the forced outage rates of the conventional plants were enforced. As a result, the tails of the duration curves show significant differences. The periods of higher % NS and lower % NS both increase. These same trends can be observed by comparing Scenario 2 with Scenario 2a in Figure 7-30. Table 7-8 provides the maxima and minima of % NS for each of the scenarios studied.

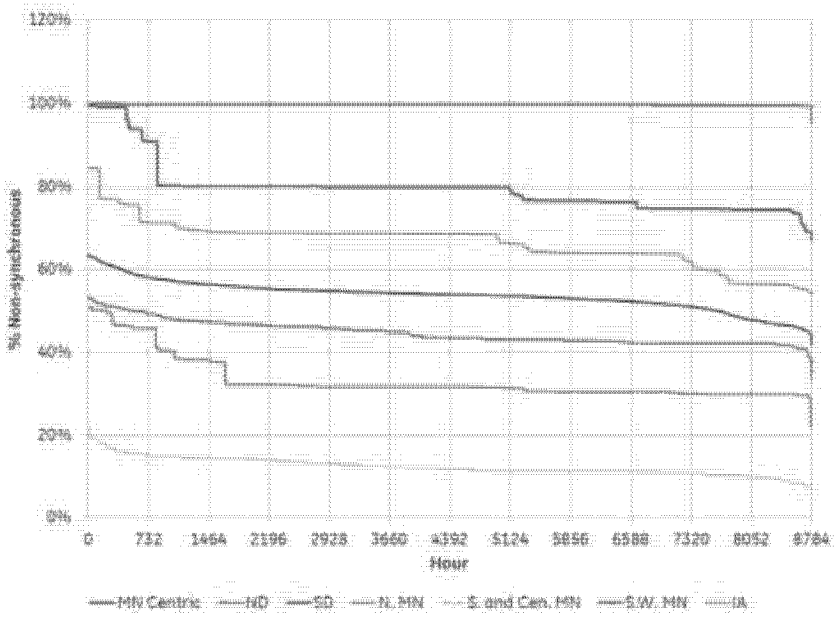

Figure 7-26 Baseline % NS Duration Curves

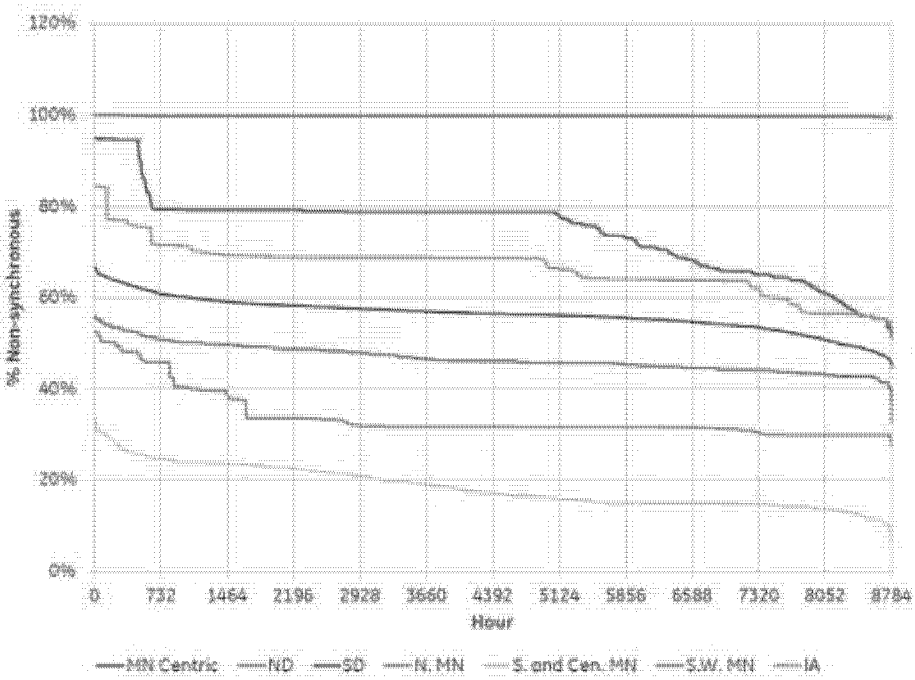

Figure 7-27 Scenario 1 % NS Duration Curves

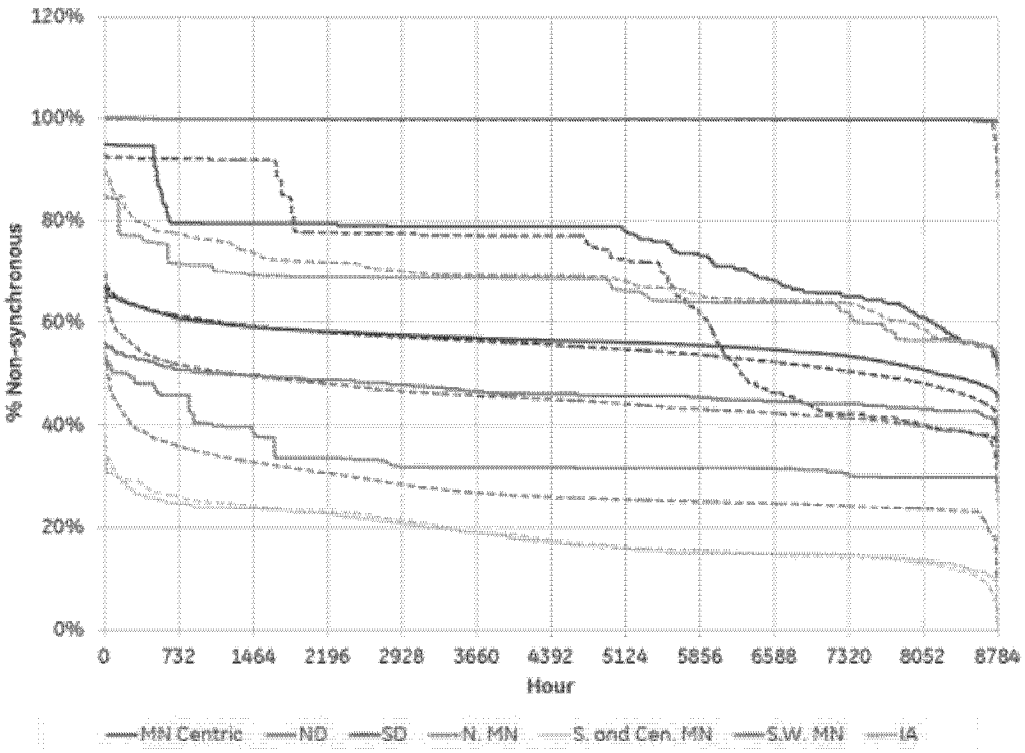

Figure 7-28 Scenario 1 (solid) and 1a (dashed) % NS Duration Curves

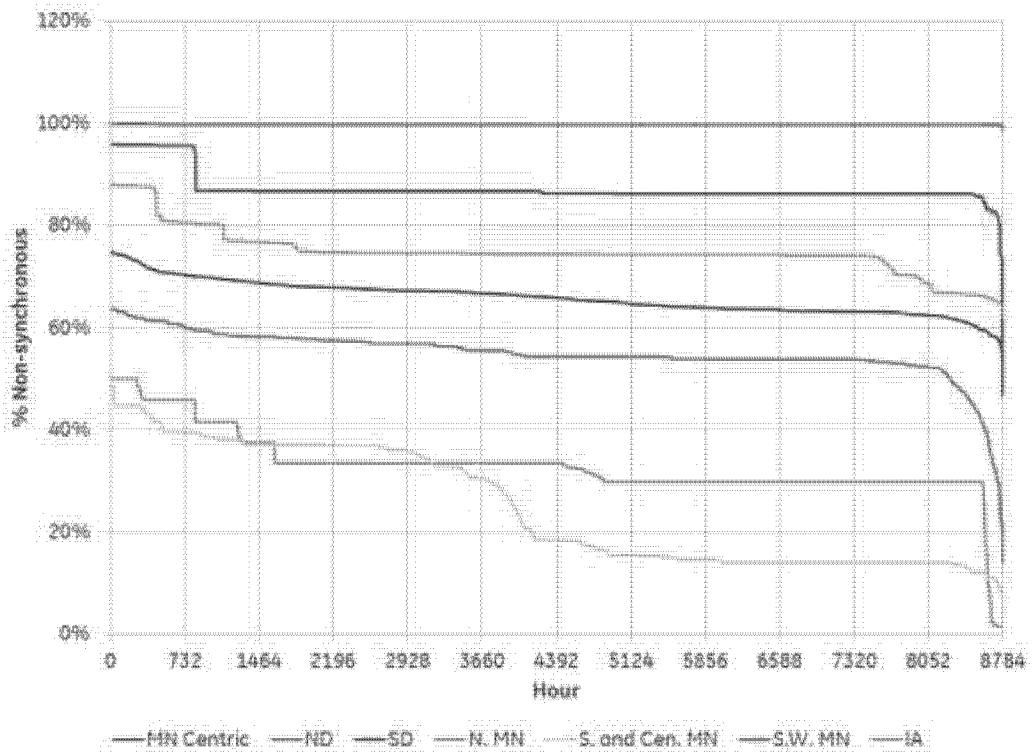

Figure 7-29 Scenario 2 % NS Duration Curves

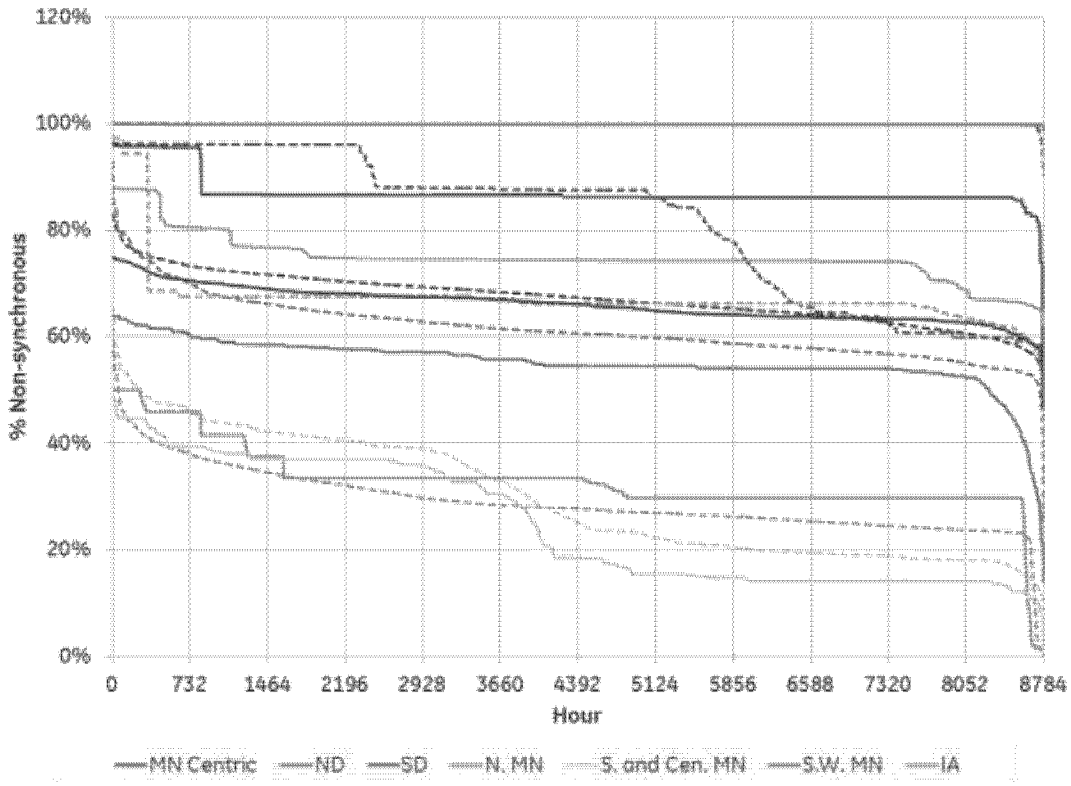

Figure 7-30 Scenario 2 (solid) and 2a (dashed) % NS Duration Curves

Table 7-8 Maximum and Minimum % NS Values

Scenario	Minnesota Centric	Northern Minnesota	South & Central Minnesota	Southwest Minnesota	North Dakota	South Dakota	Iowa
Baseline	Max: 64% Min: 42%	Max: 51% Min: 22%	Max: 22% Min: 6%	Max: 100% Min: 95%	Max: 53% Min: 34%	Max: 99% Min: 67%	Max: 85% Min: 53%
Scenario 1	Max: 67% Min: 45%	Max: 53% Min: 28%	Max: 34% Min: 6%	Max: 100% Min: 99%	Max: 56% Min: 33%	Max: 95% Min: 51%	Max: 85% Min: 54%
Scenario 1a	Max: 70% Min: 40%	Max: 56% Min: 0%	Max: 38% Min: 0%	Max: 100% Min: 85%	Max: 70% Min: 25%	Max: 93% Min: 37%	Max: 90% Min: 50%
Scenario 2	Max: 75% Min: 52%	Max: 50% Min: 0%	Max: 48% Min: 0%	Max: 100% Min: 99%	Max: 64% Min: 14%	Max: 96% Min: 47%	Max: 88% Min: 62%
Scenario 2a	Max: 83% Min: 52%	Max: 62% Min: 0%	Max: 66% Min: 9%	Max: 100% Min: 90%	Max: 93% Min: 25%	Max: 96% Min: 45%	Max: 97% Min: 44%

7.7.5 Percent Renewable Penetration Analysis

Figure 7-31 shows duration curves of the % RE metric for the Minnesota Centric region for all five scenarios. The general trend from Baseline to Scenario 1 to Scenario 2 is an increase in the % RE penetration as the wind and solar levels increase and conventional generation is backed down to accommodate the increased output.

Scenario 1a has a slightly higher % RE than Scenario 1, consistent with the change in % NS between the two scenarios. Conversely, Scenario 2a has a significantly lower % RE than Scenario 2. This is contrary to % NS which is higher for Scenario 2a than Scenario 2. This is primarily related to the changes in modeling assumptions for the coal units. In Scenario 2a where coal units are economically committed, fewer MW of ST Coal and CC generation are committed over the course of the year, but when a plant is committed it is run at a higher capacity factor. This behavior is documented in Section 7.4, where the transition from Scenario 2 to Scenario 2a, sees fewer TWh of ST Coal and CC generation being committed, but the dispatched TWh increasing.

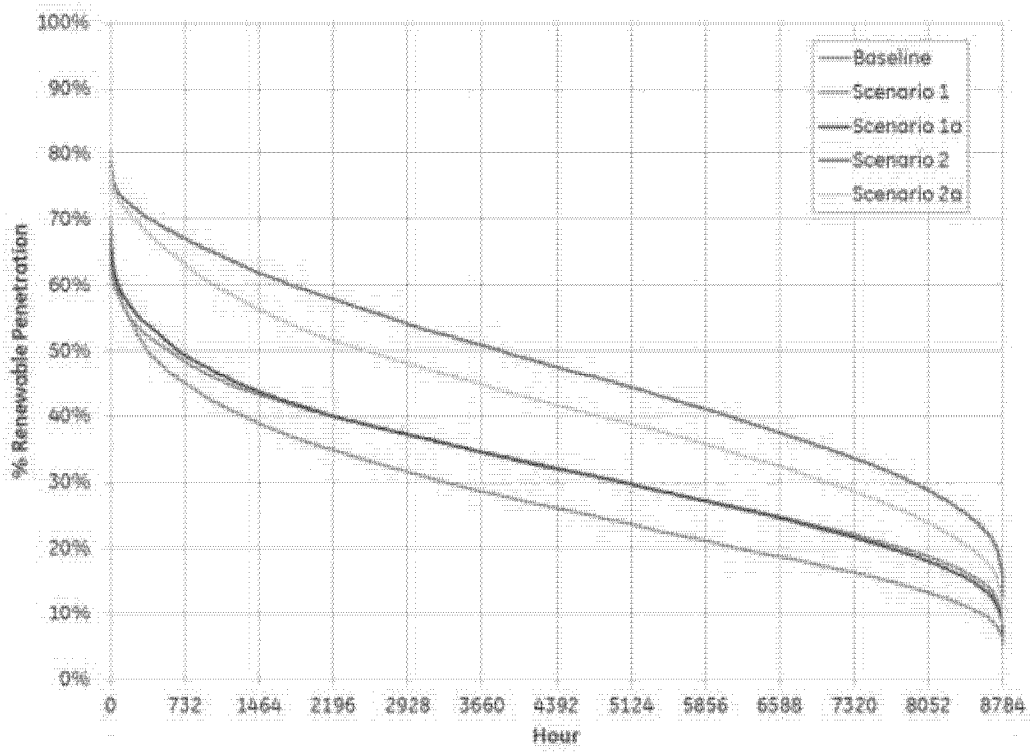

Figure 7-31 % RE Penetration for the Minnesota-Centric Region

7.7.6 Transmission Interface Loading

During periods of high transmission interface loading, the grid could be more vulnerable to power swings after transmission system faults.

In Figure 7-32 through Figure 7-34, the interface loading duration curves are compared for Scenario 1 and Scenario 1a. These were the only two scenarios that were analyzed as they were the only ones that were studied for the dynamic analysis.

For each of the three interfaces an increase in interface loading is observed as the dispatch and commitment moves from Scenario 1 to Scenario 1a for the NDEX (Figure 7-32) and MWEX (Figure 7-34) interfaces. This is due to the fact that there is an overall increase in the ST Coal in the sub-regions close to the interfaces. Both NDEX and MWEX see increases due to additional coal energy in North Dakota and Northern Minnesota from plants that were retired in Scenario 1 but were part of the ST Coal fleet in Scenario 1a. The Buffalo Ridge Outlet flow (Figure 7-33) is nearly the same in Scenarios 1 and 1a because these lines are primarily loaded with wind and solar power, which is nearly the same in both scenarios.

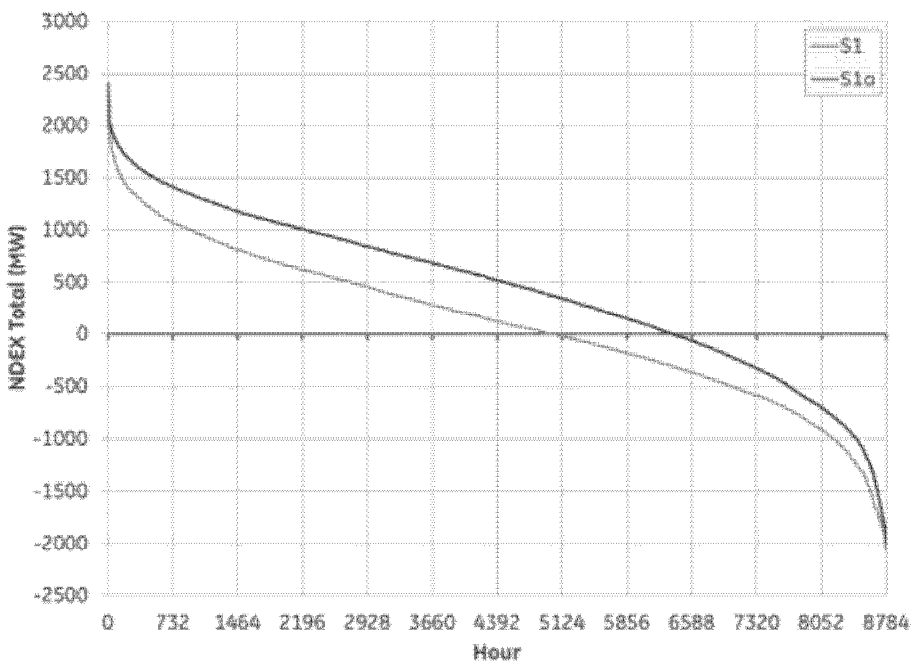

Figure 7-32 NDEX Total Loading for Scenario 1 and Scenario 1a

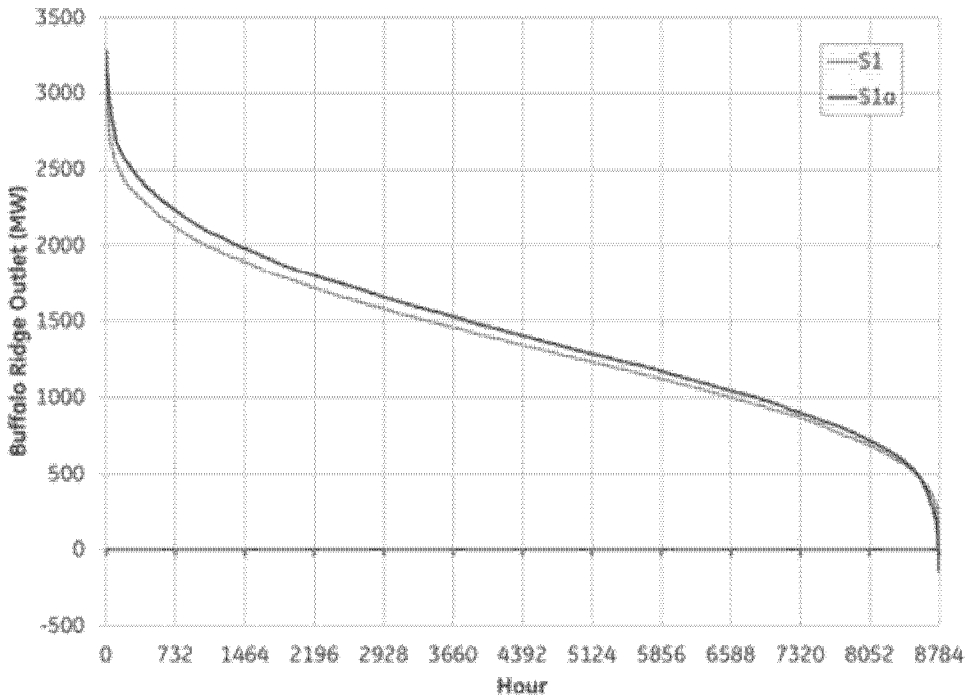

Figure 7-33 Buffalo Ridge Outlet Loading for Scenario 1 and Scenario 1a

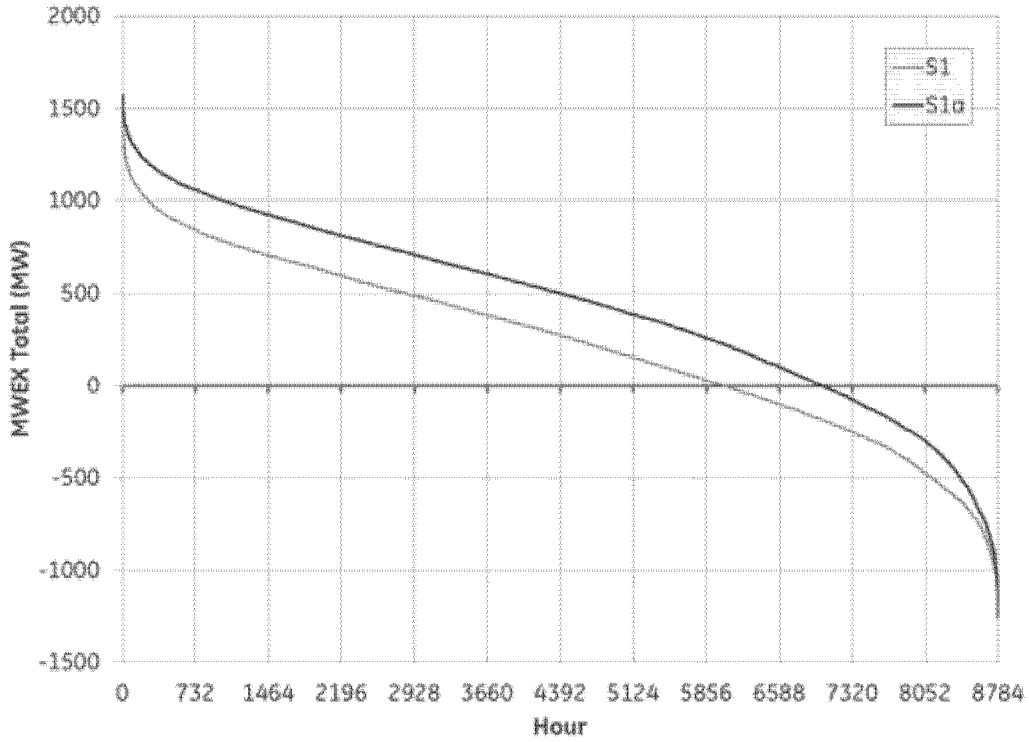

Figure 7-34 MWEX Total Loading for Scenario 1 and Scenario 1a

7.8 Selection of Operating Conditions for Dynamic Analysis

Using the three metrics described in the previous section, seven stability cases were selected for each of the two studied scenarios, Scenario 1 and Scenario 1a, for a total of 14 cases. First they were screened based on the Scenario 1 data followed by a secondary screening and adjustment if necessary based on the Scenario 1a data.

This section describes the process of using the metrics to identify the stability cases. The goal of the screen process was to filter down the 8784 hours of operation from the production simulation results into small groups of hours with common operating conditions that would facilitate in building a commitment and dispatch in the appropriate power flow case.

The first metric used to screen for stability cases was the % NS measure. The following process was used to identify appropriate cases to feed into the dynamic stability assessment.

1. The hourly % NS data for the scenario is plotted against the load duration curve for the Minnesota-Centric region. The load curve is segmented into 3 regions (peak, shoulder, light) that correspond to the power flow cases (Figure 7-35). This provided system load levels that would serve as filters for the next step.

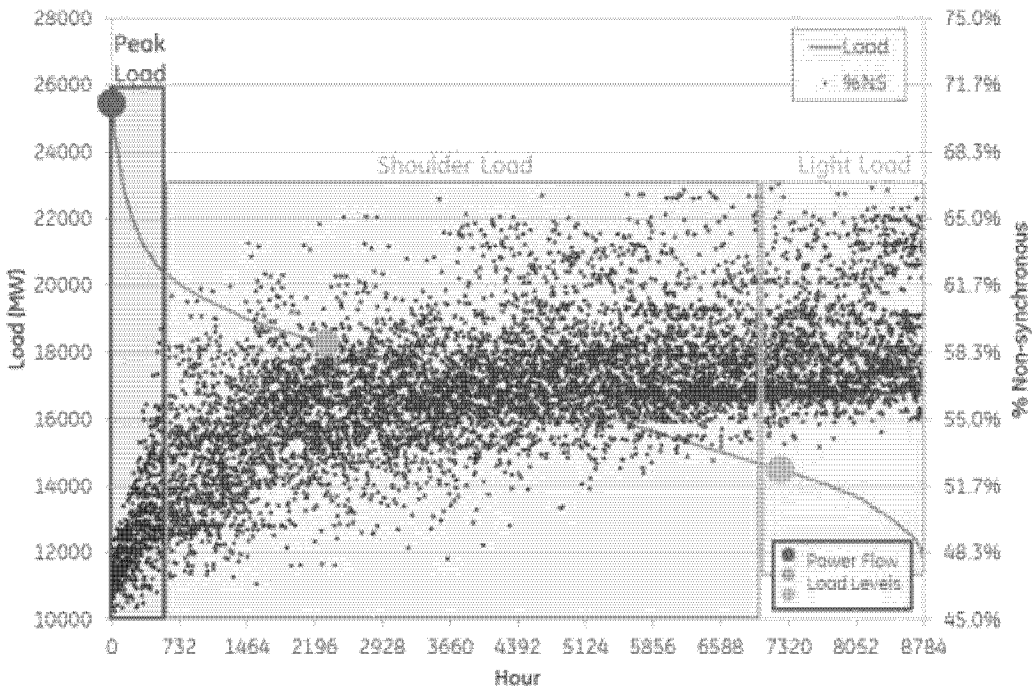

Figure 7-35 Load Duration Curve and % NS for the Minnesota-Centric Region

2. Next, the load and corresponding hourly % NS values were plotted chronologically (as in Figure 7-36). Once again, loading levels that corresponded to the power flow cases (peak, shoulder, light) were identified and used to refine the loading windows in hours with similar characteristics.

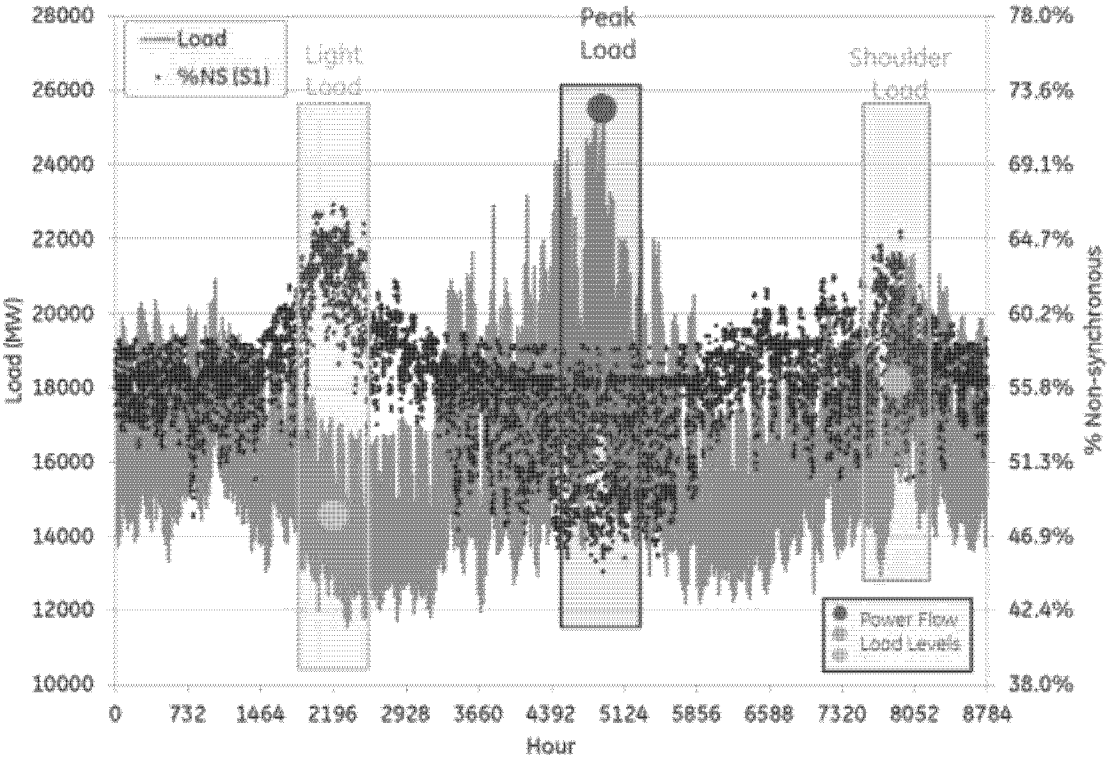

Figure 7-36 Chronological Load and % NS for the Minnesota-Centric Region

3. To identify a group of hours with similar operating conditions, the data was filter by time of year (fall), system load level (shoulder) and highest % NS (>55%). The result was 118 hours that satisfied the criteria (Figure 7-37).

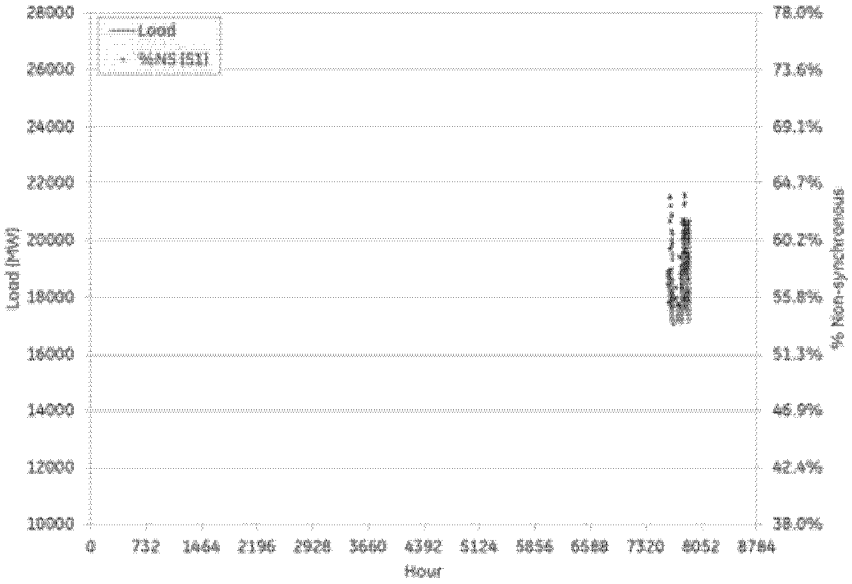

Figure 7-37 Filtered Load and % NS to the Fall Shoulder-Load Window

4. These 118 hours were then sorted by time of day to ensure that the hours with online solar (daytime hours) were captured and allowed for consistent hours in the commitment and dispatch (Figure 7-38). This resulted in 15 hours where the commitment and dispatch had very high % NS levels during a very small window.

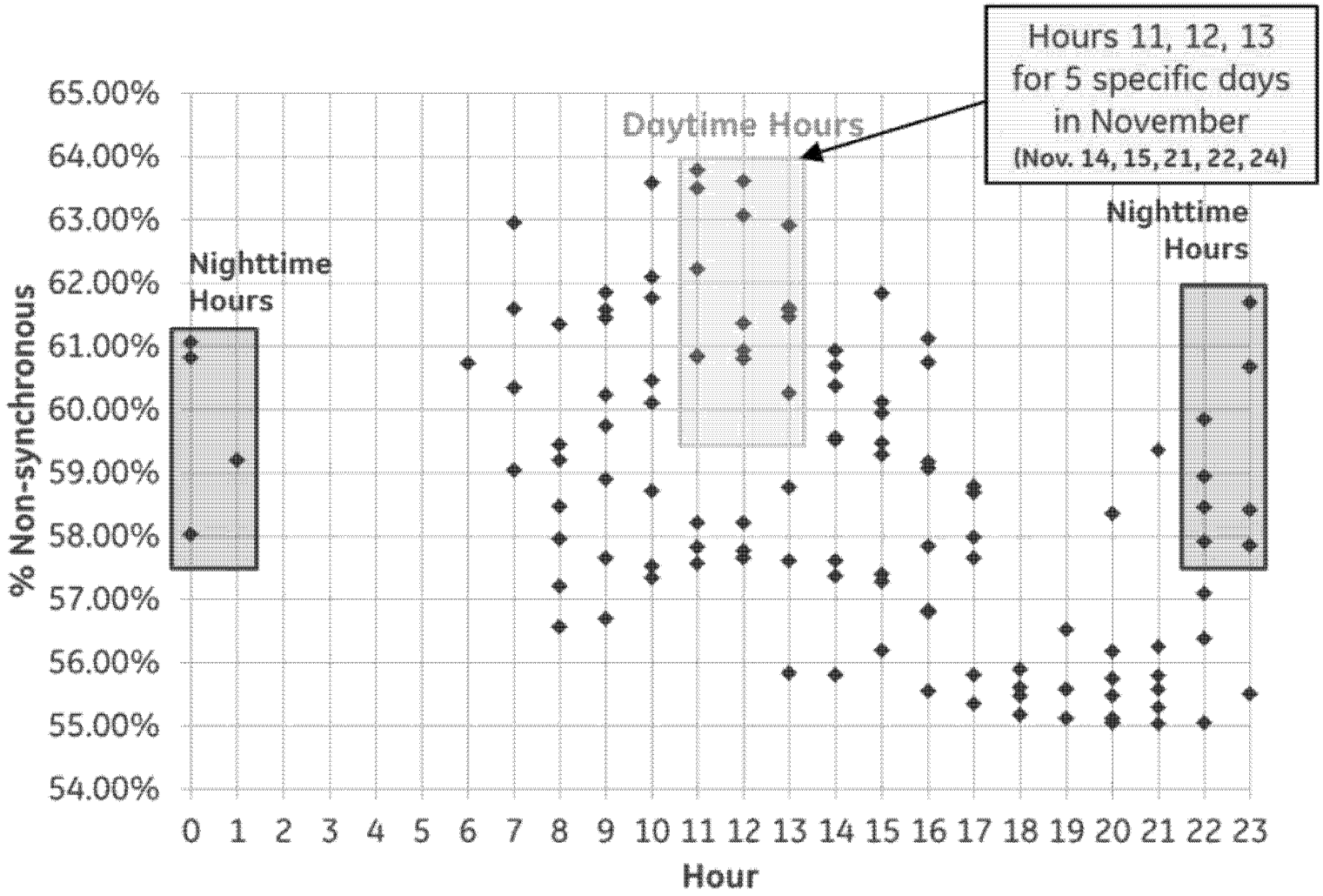

Figure 7-38 Further Filter Fall Shoulder Hours for Scenario 1 Stability Analysis

Through this same methodology a further two stability cases were selected for the % NS case that corresponded to the peak load and light load periods and a high % RE case that corresponded to a light load period. Three additional cases were selected using the interface loading metric for a total of seven Scenario 1 stability cases (Table 7-9).

Table 7-9 Stability Cases for Scenario 1

Case	Criteria	Load	Day / Night	Notes
1	High % NS	Shoulder	Day	55% - 64% NS, 5 days in Nov., 11am – 1pm
2	High % NS	Light	Night	%NS > 60%, April 2-8, 12am-7am
3	High % NS	Peak	Day	46% - 51% NS, July 21-27, 2pm-7pm
4	High % RE Penetration	Light	Night	%RE > 55%, Avg. 71% Oct. 1, 5-7, 12am - 7am
5	High Transmission Loading NDEX	Shoulder	Night	Path Loading>1900 MW, Oct. 25 – 30
6	High Transmission Loading Buffalo Ridge Outlet	Shoulder	Night	Path Loading>2800 MW, May 20 – 22
7	High Transmission Loading MWEX	Light	Day	Path Loading>1400 MW, June 8, 11, 14

Next, the seven cases were re-screened to ensure that the commitment and dispatch windows still corresponded to the limits of the defined stability metrics. For the interface loading metric, the three cases for Scenario 1, corresponded with the new data for Scenario 1a for the NDEX (Figure 7-39), Buffalo Ridge Outlet (Figure 7-40) and the MWEX (Figure 7-41) interfaces.

For the NDEX interface, the period highlighted in Figure 7-39, indicates an interface loading greater than 1900 MW. For the Buffalo Ridge Outlet interface, the highlighted period in Figure 7-40 indicates an interface loading greater than 2800 MW. Finally, for the MWEX interface, the highlighted period in Figure 7-41 indicates an interface loading greater than 1400 MW. These values are based on the highest observed flows on the interfaces and do not correlate with a particular stability limit for the system.

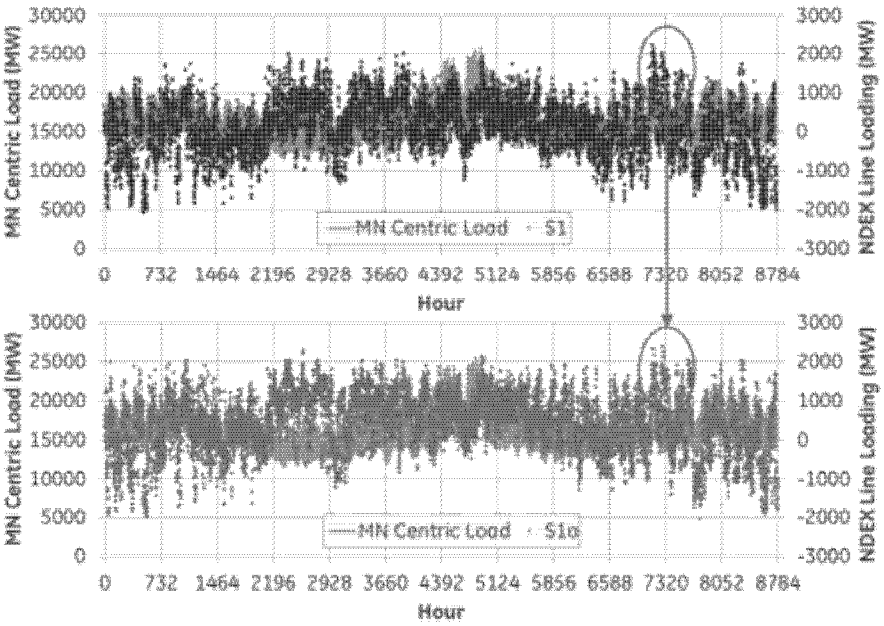

Figure 7-39 NDEX Interface Screening for Scenario 1 and Scenario 1a

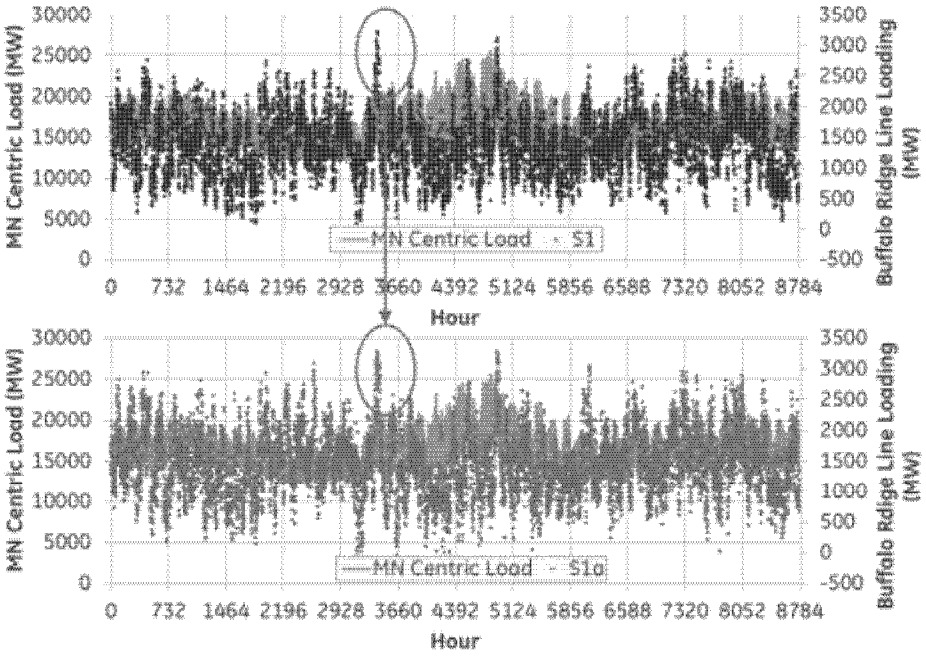

Figure 7-40 Buffalo Ridge Outlet Interface Screening for Scenario 1 and Scenario 1a

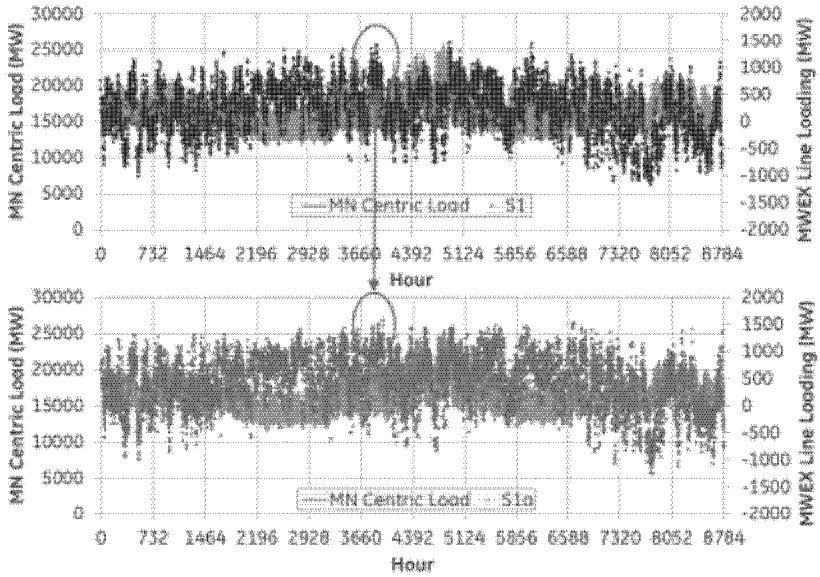

Figure 7-41 MWEX Interface Screening for Scenario 1 and Scenario 1a

For the remaining four cases, Cases 1, 3 and 4 showed close correlation between Scenario 1 and Scenario 1a. As a result, the dispatches between these cases were compared and the power flow for the cases was adjusted according to the new Scenario 1a commitment and dispatch. Case 2 was the only case that required an adjustment of the stability window.

As seen in Figure 7-42, a new peak in % NS for the light load case was observed around hour 3000 in Scenario 1a. As such, the methodology described previously in this section was applied and new commitment and dispatch for Case 2 was developed based on the Scenario 1a data. Overall, the new commitment and dispatch from Scenario 1a for Case 2 resulted in a net increase of 1288 MW of non-synchronous generation commitments.

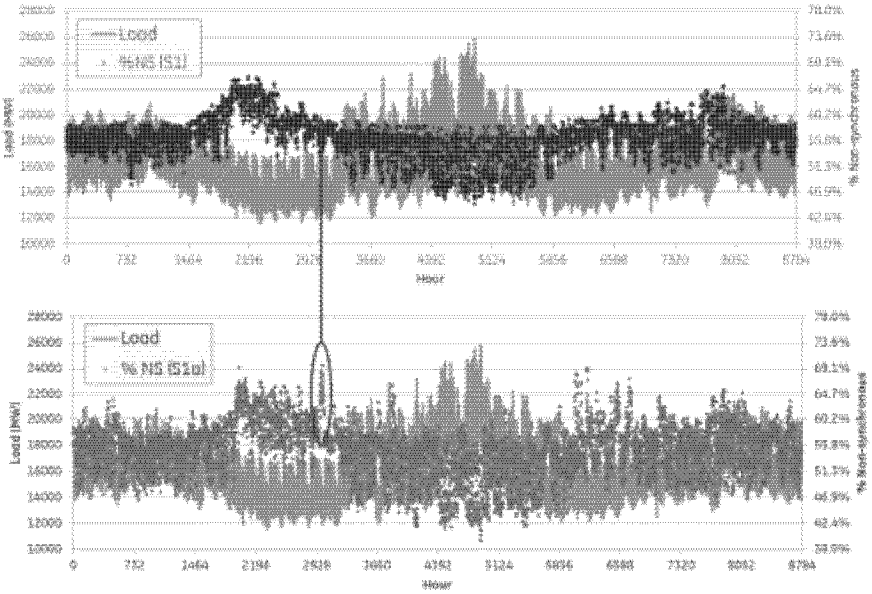

Figure 7-42 Case 2 Stability Screening for Scenario 1 and Scenario 1a

8 DYNAMIC SIMULATION RESULTS

The objective of this analysis was to tests the dynamic performance of the system under the most challenging system conditions observed in the scenario S1 and S1a production simulation analysis with respect to renewable generation.

The dynamic study cases developed for the S1 analysis represent a full spectrum of operating conditions cover light load, shoulder load and peak load. Every wind plant was on line for each of the study cases. All PV plants and distributed PV were on line for daytime cases and off line for nighttime cases. Renewable generation levels were set based on the production simulation results for the condition being simulated.

The cases cover a wide range of synchronous generation commitment and dispatch due to the different screening metrics used to select challenging hours. In addition, two different production simulation runs were used (S1 and S1a), with their different assumptions on must-run status, generation retirement and forced outages. The study cases represent hours with lower than average commitment and dispatch of synchronous generation, giving a high percentage of renewable energy and non-synchronous generation on line. These cases also stress several critical interfaces and transfer paths with high Manitoba Hydro exports and high Buffalo Ridge Outlet, NDEX and MWEX interface flows.

8.1 Dynamic Performance Study Conditions

Power flow study cases were developed for the seven different system conditions described in the previous section. The commitment and dispatch of all generators (both conventional and renewable) throughout and outside of MISO was set based on unit operation during the corresponding hours in the production simulation analysis. Conventional units that were on line less than 25% of the sample hours were decommitted in the power flow case. Conventional units on line more than 25% of the sample hours were committed and operated at or above their average dispatch for those hours. Renewable generation was committed and dispatched based on the average of the sample hours from production simulation.

These dynamic study cases, listed in Table 8-1, include three light load, three shoulder load and one peak load condition Case 4 was used to test high MWEX transfers at light load. The table lists the case number from the production simulation analysis, the stability case name, the selection criteria, load level and comments. The notes include the percentage of non-synchronous generation (%NS) and percentage of renewable energy (%RE) for the Minnesota-centric region. These are calculates as:

$$\%NS = \frac{Total\ online\ wind + Solar\ MW\ rating}{Total\ online\ generation\ MW\ rating}$$

and

$$\%RE = \frac{Wind + Solar\ MW\ dispatched}{Total\ Generation\ MW\ dispatched}$$

The notes also include information on high transmission loading where applicable. Note that analysis of high MWEX loading (case 7, light load) was performed using the light load case with high percentage of renewable energy (case 4), since this case has very high MWEX loading. Additional contingencies on the highest loaded MWEX lines were simulated to focus on the impact of high transfers.

Table 8-1 Stability Case Description

Case	Name	Criteria	Load	Notes
1	S1_SH_D01	High % NS	Shoulder	49% NS Generation 37% Renewable Energy
2	S1_LL_D02	High % NS	Light	48% NS Generation 36% Renewable Energy
3	S1_PK_D03	High % NS	Peak	37% NS Generation 21% Renewable Energy
4	S1_LL_D04	High % RE Penetration	Light	47% NS Generation 40% Renewable Energy
5	S1_SH_D05	High Transmission Loading NDEX	Shoulder	47% NS Generation 37% Renewable Energy 2334 MW NDEX Loading
6	S1_SH_D06	High Transmission Loading Buffalo Ridge Outlet	Shoulder	48% NS Generation 41% Renewable Energy SW Minn Renewables at 95% Pmax
7	S1_LL_D04*	High Transmission Loading MWEX	Light	47% NS Generation 40% Renewable Energy 2424 MW MWEX Loading

*** Note:** Case 4 has MWEX loading above 1400 MW (max value from production simulation). The impact of MWEX loading was tested using this case, subject to additional contingencies on MWEX lines.

The MW dispatch of all Minnesota-centric generation is illustrated in Figure 8-1. This bar graph shows the total on-line generation in MW by type for each of the six study cases. Figure 8-2 shows the same information, but in the form of pie charts of the percentage of generation by type. This is similar to the percent renewable energy measure (%RE) used for the production simulation screening. The dispatches are shown in order of increasing generation, from light load to shoulder load to peak load.

The reporting of %RE for the stability cases is lower than that reported in the production simulation analysis due to differences in the grouping of generation. However, the generation dispatch for each case matches the average dispatch for the selected time period in the production analysis.

Figure 8-3 shows the total MVA of committed Minnesota-centric generation by type for the six study cases. This measure sums the rated MVA of each on-line unit. It does not consider the MW output of the machine, only if the unit is on-line or not. Figure 8-4 presents the same information, but groups the generation as synchronous and inverter-based. The inverter-based generation us made up of all wind, solar PV and distributed PV since most of this generation is power electronic inverter based. Inverter-based generation is also referred to as non-synchronous. This figure shows the rated MVA of each type as a percentage of total on-line MVA. This measure is similar to the percent non-synchronous generation (%NS) used for production simulation screening. Note that HVDC converter stations are not included in the calculation of percent non-synchronous.

The measure of %NS for the light and shoulder load study cases is between 47% and 48% across the Minnesota-centric area. The measure of %NS for the peak load case is 37%. These measures are lower than the %NS reported in the production simulation analysis. This difference is due to three factors:

1. These calculations are based on the sum of rated MVA of on-line generators, where the production simulation analysis is based on the sum of rated MW. In general, a synchronous machine will have a higher MVA rating than a wind or PV plant with the same MW capability. This will lower the measure of percent non-synchronous.
2. There are over 2700 MVA of synchronous units that were not included in the %NS calculations for production simulation, but are included in the calculations for stability analysis. This includes the two Quad Cities nuclear units (1068 MVA each).
3. Over 4600 MW of the renewable generation added for Baseline and S1 scenarios was located at buses outside the Minnesota-centric footprint. These are modeled and included in the stability analysis but not accounted for in calculating the %NS measure.

While the calculation of %NS differs between the production simulation and stability cases, the actual commitment/dispatch in the stability simulations matches that of the production simulation.

Figure 8-5 shows the percentage of on-line synchronous and non-synchronous generation (based on rated MVA) for each of the six regions in the Minnesota-centric footprint for each study case. The same information is shown in Figure 8-6, but shown as total MVA. SW Minnesota is nearly 100% non-synchronous generation for all of the dispatches. South Dakota averages over 60% NS, and is as high as 80% NS for the two light load cases. Iowa and North Dakoda have between 40% NS and 50% NS across the cases, and Northern, Central and South Minnesota have 20% or less %NS.

Figure 8-7 shows the dynamic reactive reserves from synchronous, non-synchronous and static var compensator SVC (labeled "Other") sources for each region. The dynamic reactive reserves are calculated as the difference in the maximum reactive capability minus the reactive output of a unit. This calculation does not include mechanically switched capacitors.

The dynamic reactive reserves closely follow the on-line MVA for each region. The renewable generation provides a significant portion of the dynamic reactive reserves in Iowa, North and South Dakota. All of the reactive reserves in SW Minnesota are from renewable generation sources. The ±60 MVAr SVC at Lake Yankton was not included in this analysis.

The reactive reserves in Northern Minnesota are from synchronous generators and the Forbes SVC. The SVC is critical to supporting imports from Manitoba Hydro (MH). One objective in developing the power flow cases was to maintain over 350 MVAr of dynamic reserves from the SVC. This was achieved using the mechanically switched shunt capacitors associated with the SVC.

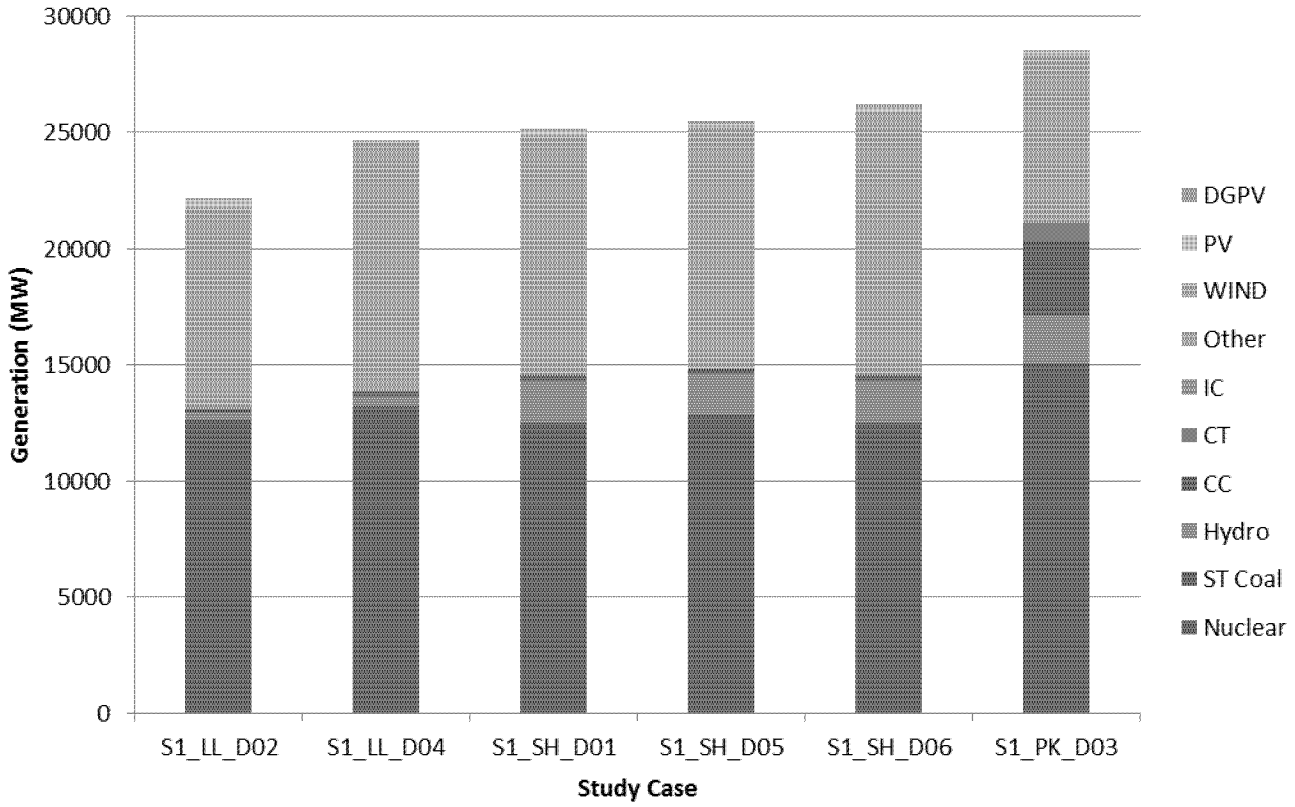

Figure 8-1 Minnesota Centric Dispatch (MW) By Unit Type

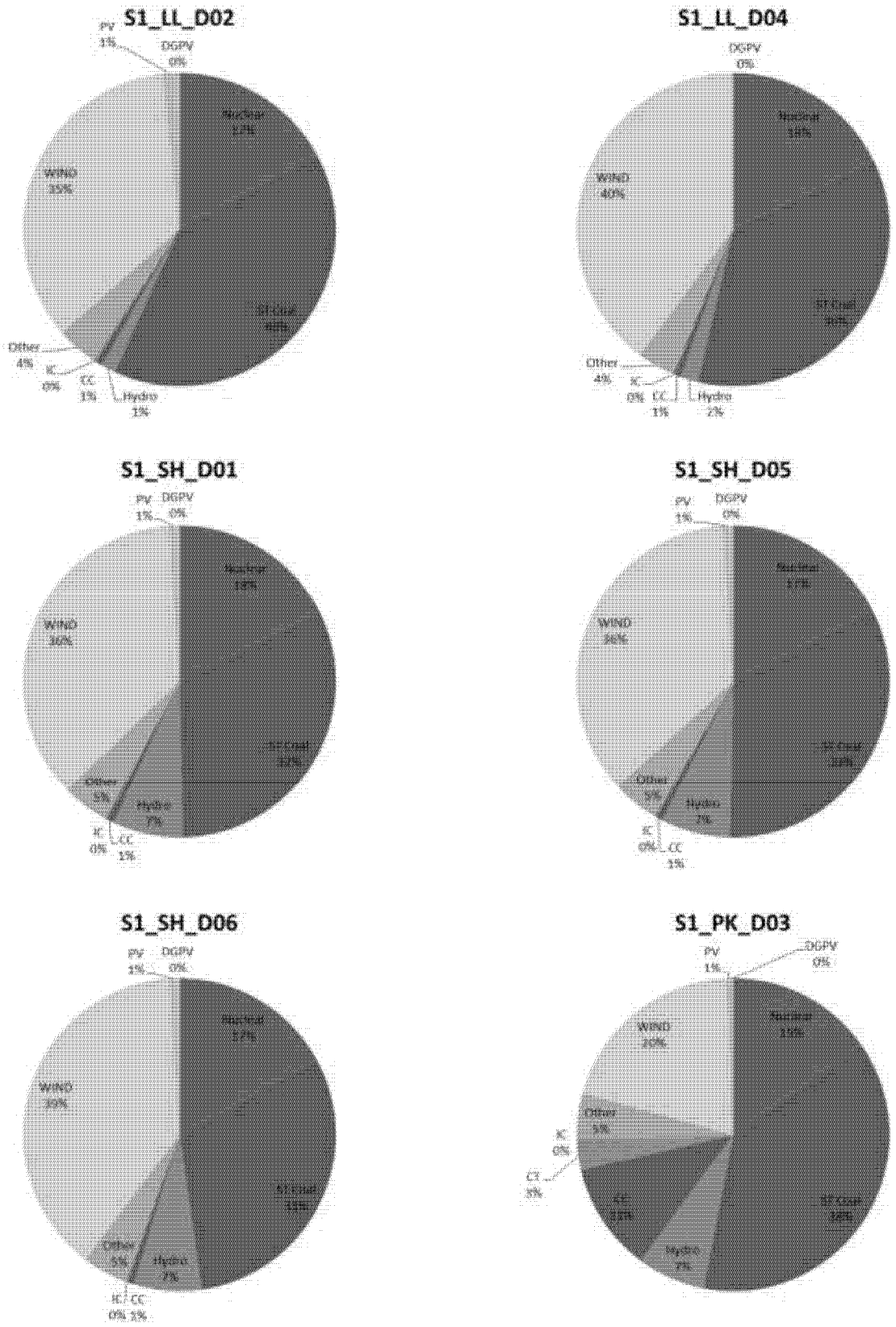

Figure 8-2 Minnesota Centric Percentage Generation Dispatch by Type

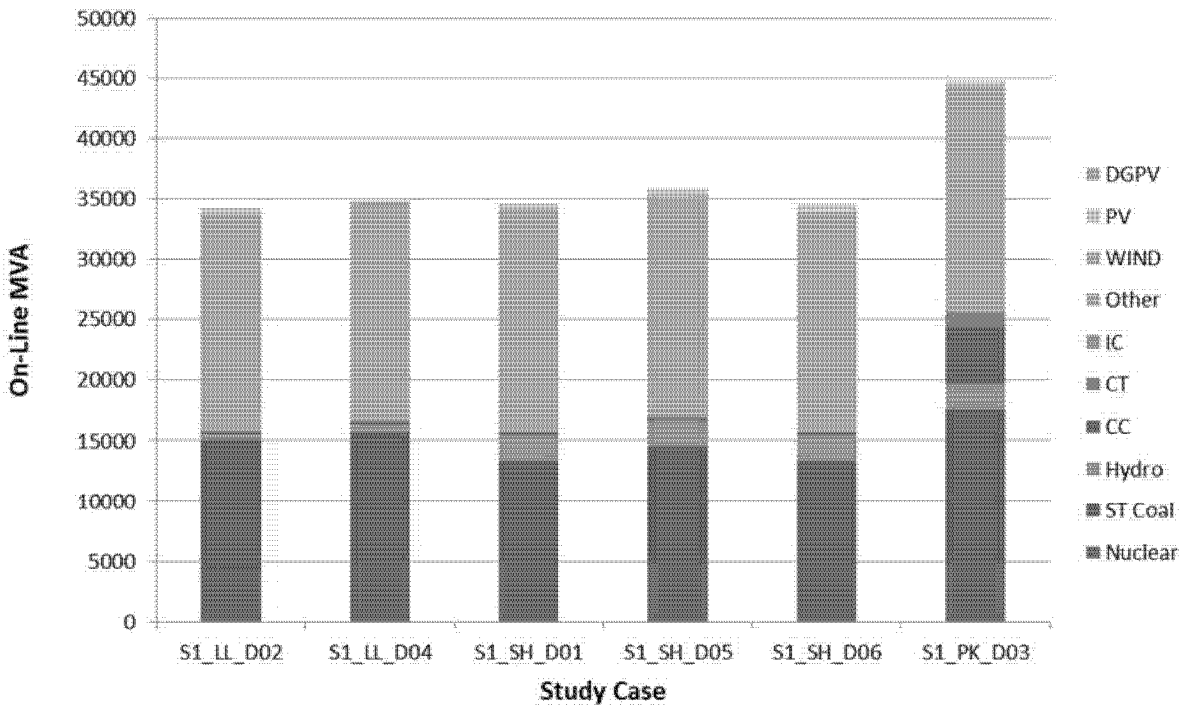

Figure 8-3 Minnesota Centric Commitment (MVA) by Unit Type

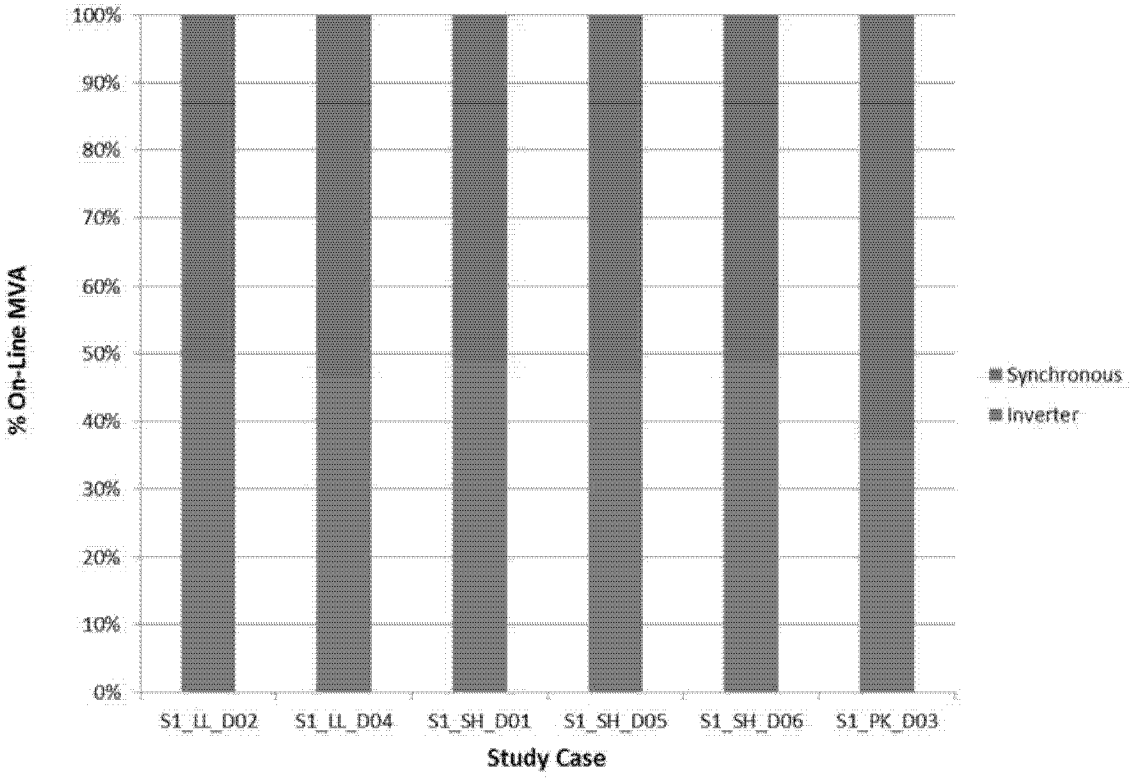

Figure 8-4 Percentage of On-line Non- vs Synchronous MVA

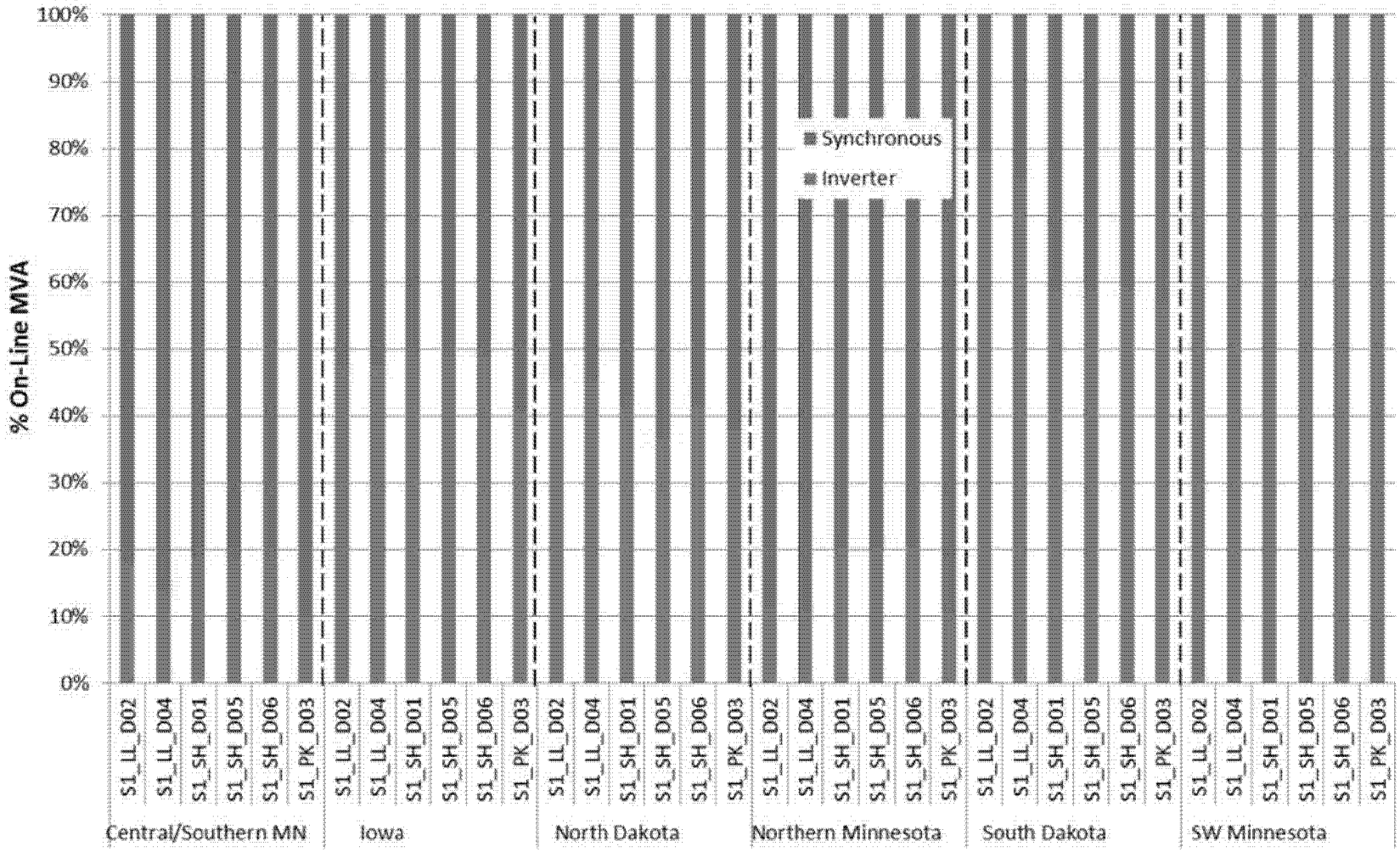

Figure 8-5 Percentage of online, non- and synchronous MVA by Sub-Region

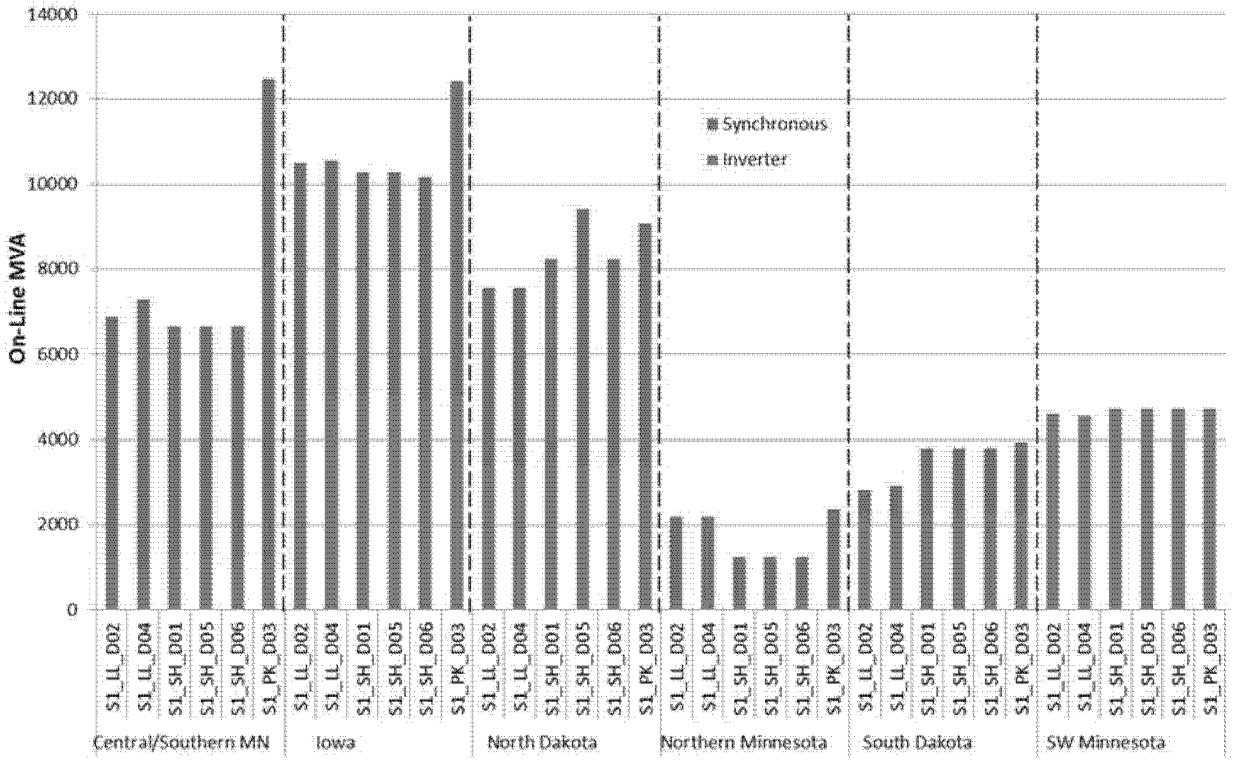

Figure 8-6 Online MVA of synchronous and non-synch Generation by Region

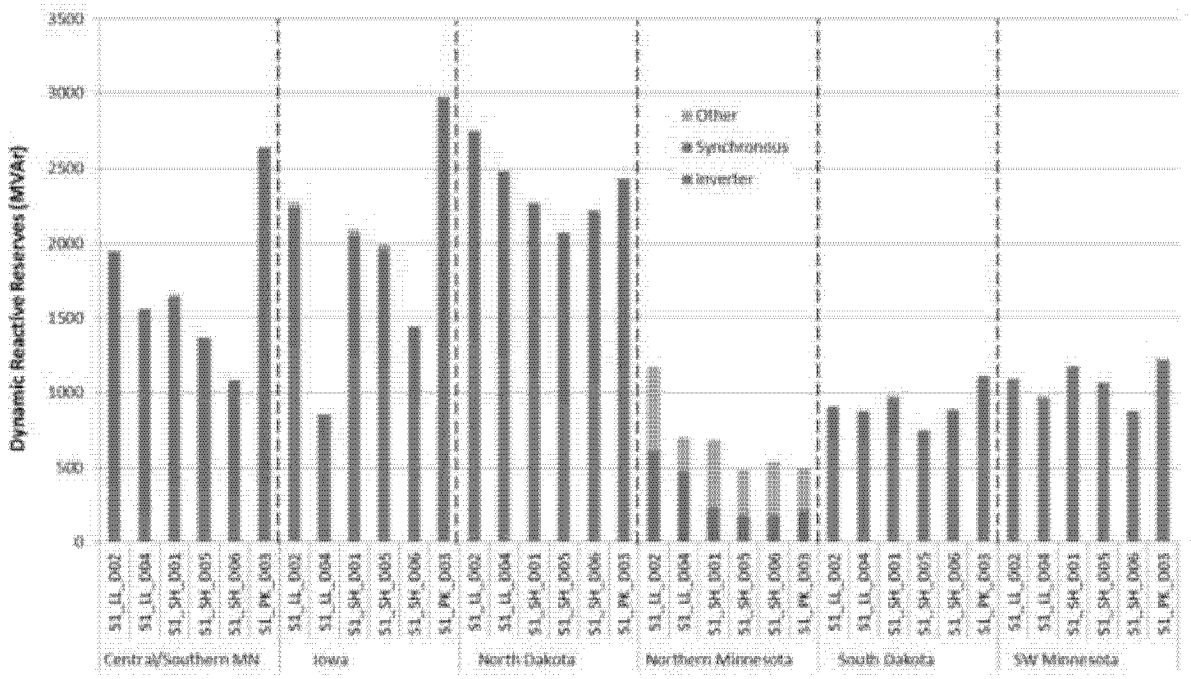

Figure 8-7 Dynamic Reactive Reserves of synchronous and non-synch Generation by Region

8.2 Voltage Regulation & Stability Analysis

8.2.1 Disturbances

This study considers a wide range of contingencies, listed in Table 8-2. The list of faults covers reference disturbances, disturbances in areas with low short circuit strength and faults along transmission interfaces. Faults 1 through 5 are established contingencies that test the traditional stability limitations of the system. Faults 6 through 10 (LSC1 through LSC5) and 16 were selected based on the weak system (low short circuit strength) analysis. These lines have the highest contribution to short circuit strength of the SW Minnesota region. Fault 11 tests the stability and voltage recovery of the Twin Cities area and Fault 12 tests a fault with generation tripping near SW Minnesota. Faults 13 through 16 were developed for high transmission loading cases (cases 5 through 7) only.

Table 8-2 Fault Description for Stability Analysis

No.	Fault Name	Description
1	EI2	CU HVDC Permanent Bipole fault with tripping of both Coal Creek units
2	AG1	SLG fault with breaker fail at Leland Olds on the Ft. Thompson 345 kV line
3	AG3	3 phase fault at Leland Olds on Ft. Thompson 345 kV line, Clear both ends of the line in 4 cycles
4	NAD	4cycles 3 phase fault on the Dorsey to Forbes 500 kV line D602F at Forbes. Runback bi-poles that terminate at Dorsey
5	PCS	SLG fault t with breaker fail at King with 8P6 stuck. Trips King-EauClaire-Arpin and King-Chisago 345 kV line
6	LSC1	3Φ Fault at Nobles on Lakefield Jct 345 kV line, clear both ends of the line in 4 cycles
7	LSC2	3Φ Fault at Fallow on Grimes 345 kV line, clear both ends of the line in 4 cycles
8	LSC3	3Φ Fault at Brookings Co. on Big Stone South 345 kV line, clear both ends of the line in 4 cycles
9	LSC4	3Φ Fault at Split Rock on White 345 kV line, clear both ends of the line in 4 cycles
10	LSC5	3Φ Fault at Split Rock on Sioux City 345 kV line, clear both ends of the line in 4 cycles
11	Trip_DEERCK	3Φ Fault at Deer Creek 345 kV bus, clear fault in 4 cycles followed by tripping Deer Creek CC generator
12	Term_King	3Φ Fault at KOLMNLK3 on Terminal 345 kV line, clear both ends of the line in 4 cycles
13	AG1_v2	Single-line-to-ground fault with breaker fail at Leland Olds on the Groton 3 345 kV line
14	AG3_v2	Three-phase fault at Leland Olds on the Groton 3 345 kV line. Clear both ends of the line in 4 cycles
15	briggs	Three-phase fault at Briggs on the NMA 345 kV line. Clear both ends of the line in 4 cycles
16	sheas	Three-phase fault at SHEAS LK3 on the HELENA 3 345 kV line. Clear both ends of the line in 4 cycles

8.2.2 Overall Results

Transient stability analysis evaluated system response to all fault listed in Table 8-2 . Faults 1 through 12 were tested on all cases while faults 13 through 16 were tested on high transmission loading cases (cases 5 through 7) only.

All stability simulations were evaluated using the criteria describe in Section 5. This includes first swing and angular stability, possible system separation and cascading outage conditions based on operation of the system-wide generic impedance relay and post-fault voltage recovery. Transient response was considered stable if all units maintain stable response, voltage recovery meets testing criteria and there were no inadvertent impedance relay operations. The results of transient stability analysis are summarized in the Table 8-3. All tested scenarios produce transiently stable response with acceptable voltage recovery.

Table 8-3 Transient Stability Analysis Results

No	Fault Name	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
1	EI2	stable	stable	stable	stable	stable	stable	stable
2	AG1	stable	stable	stable	stable	stable	stable	stable
3	AG3	stable	stable	stable	stable	stable	stable	stable
4	NAD	stable	stable	stable	stable	stable	stable	stable
5	PCS	stable	stable	stable	stable	stable	stable	stable
6	LSC1	stable	stable	stable	stable	stable	stable	stable
7	LSC2	stable	stable	stable	stable	stable	stable	stable
8	LSC3	stable	stable	stable	stable	stable	stable	stable
9	LSC4	stable	stable	stable	stable	stable	stable	stable
10	LSC5	stable	stable	stable	stable	stable	stable	stable
11	Trip_DEERCK	stable	stable	stable	stable	stable	stable	stable
12	Term_King	stable	stable	stable	stable	stable	stable	stable
13	AG1_v2	NT	NT	NT	NT	stable	NT	NT
14	AG3_v2	NT	NT	NT	NT	stable	NT	NT
15	briggs	NT	NT	NT	NT	NT	NT	stable
16	sheas	NT	NT	NT	NT	NT	stable	NT

* NT is "Not Tested"

For transient stability analysis in this study new monitoring signals are introduced. These signals include dynamic monitoring of total active and reactive output of different types of generation (i.e. synchronous, wind, PV) and load for each of Minnesota footprint regions. The plots of selected traces of transient stability simulations are presented in the sections below.

Transient stability cases are grouped into three categories based on criteria used for their development. The categories are:

1. High percentage non-synchronous condition;
2. High percentage of renewable conditions
3. High transfer conditions,

In the following section, the system response to selected faults is presented for each category of dispatch conditions.

8.2.3 High % NS conditions

The cases developed for high percentage of non-synchronous generation in Minnesota footprint are case 1, case 2 and case 3. The faults selected to represent system response on these cases are:

Case 1: Terminal King fault (3Φ Fault at KOLMNLK3 on Terminal 345 kV line, clear both ends of the line in 4 cycles)

Case 2: Trip DEERCK fault (3Φ Fault at Deer Creek 345 kV bus, clear fault in 4 cycles followed by tripping Deer Creek CC generator)

Case 3: AG3 fault (3 phase fault at Leland Olds on Ft. Thompson 345 kV line, Clear both ends of the line in 4 cycles)

This section lists plots of total Minnesota footprint as well as Minnesota-centric regions system generation and load response. The plots of system generation include active (left column) and reactive (right column) power of all synchronous generation, wind generation, PV plus DGPV and load. The plots show the total generation/load for the Minnesota-centric region and the six sub-regions. Also post fault voltage recovery of bus voltages close to a fault are presented.

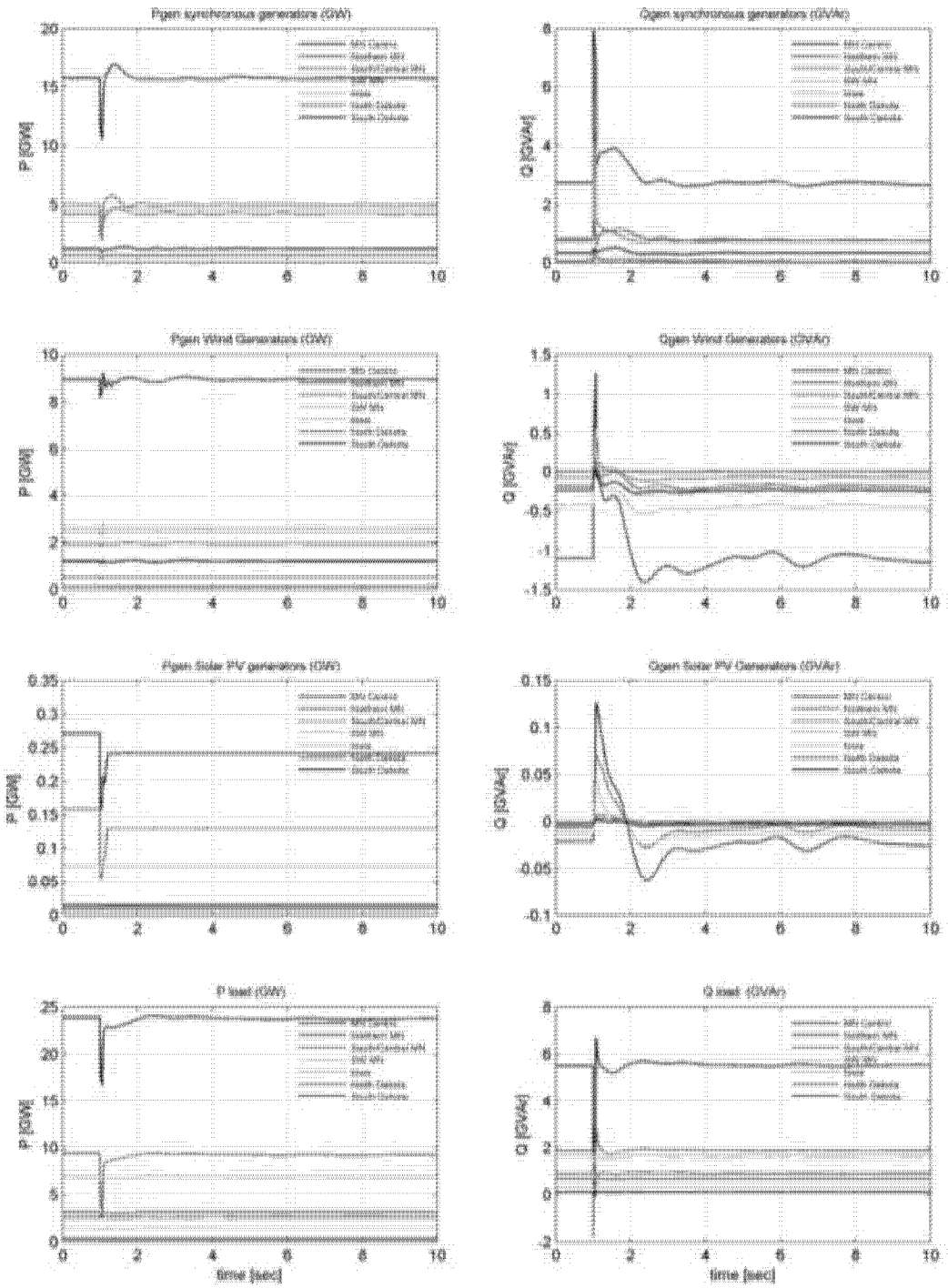

Figure 8-8 Case 1: Terminal King Fault Active and Reactive Response

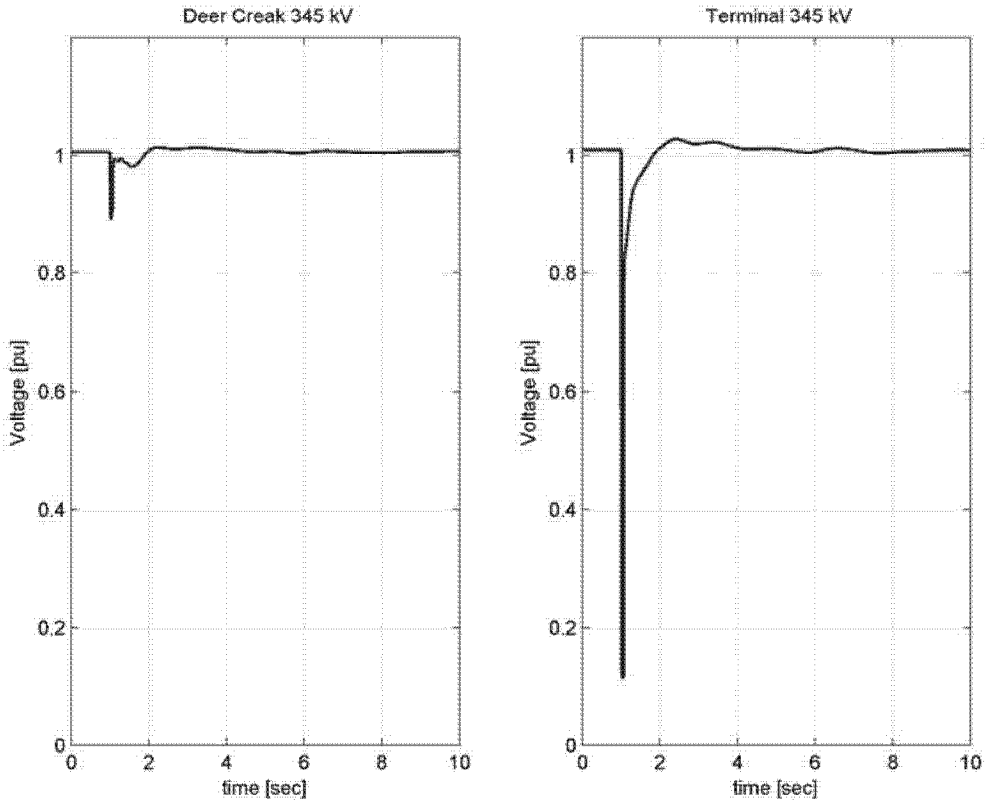

Figure 8-9 Case 1: Terminal King fault Voltage Magnitude

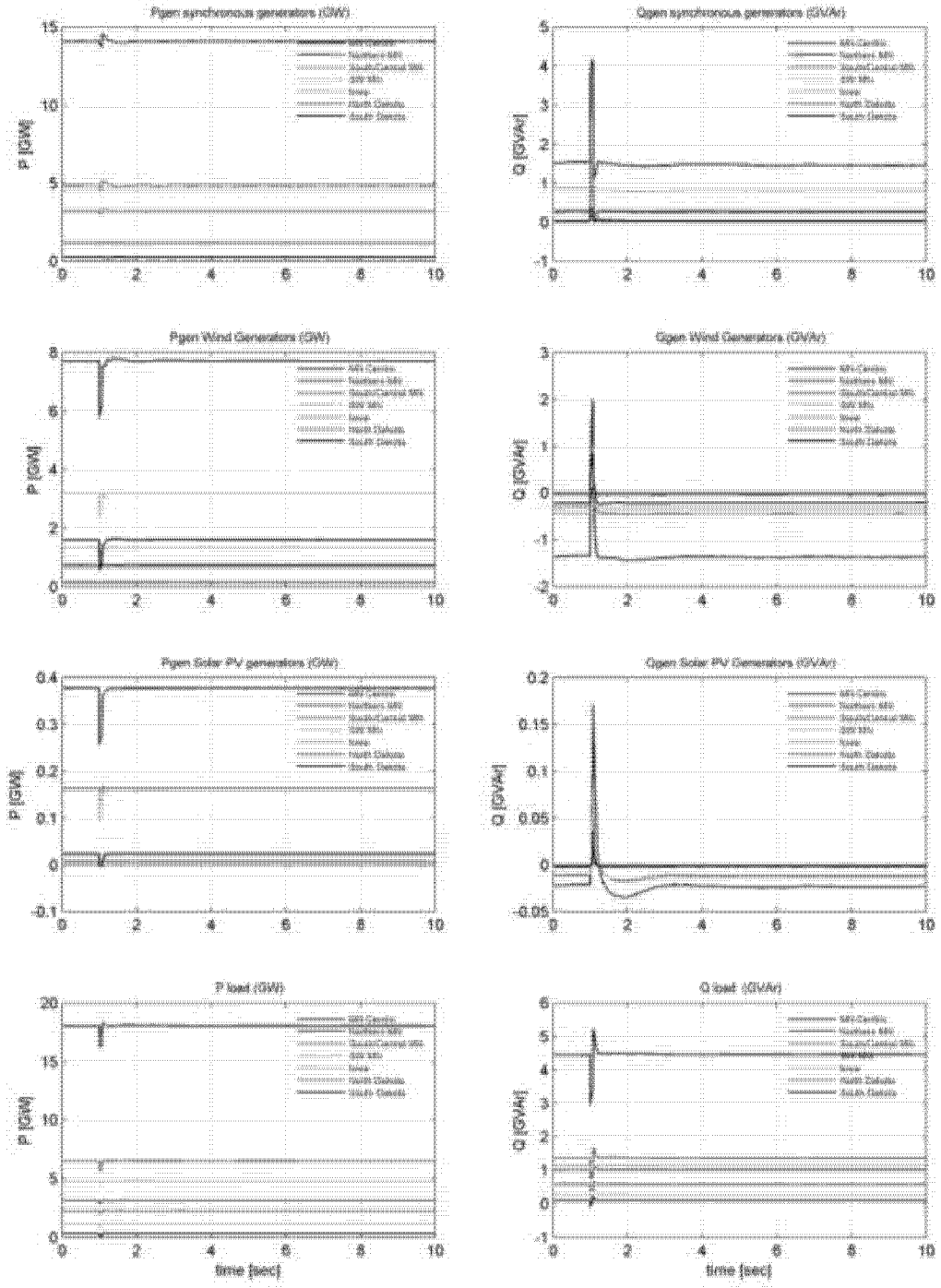

Figure 8-10 Case 2: Trip DEERCK fault Active and Reactive Response

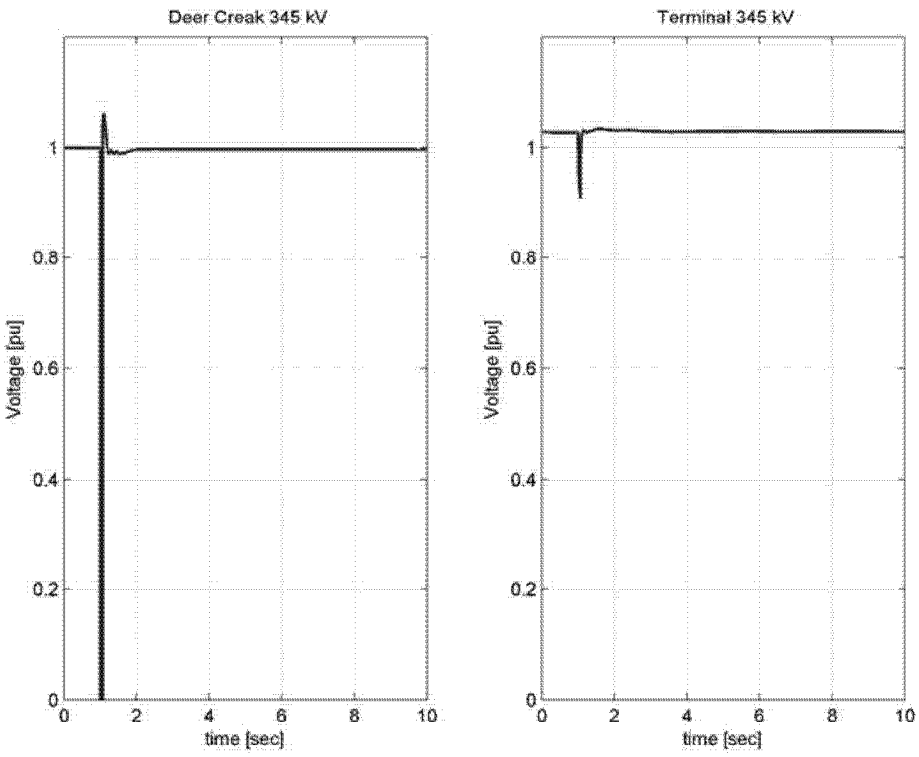

Figure 8-11 Case 2: Trip DEERCK fault Voltage Magnitude

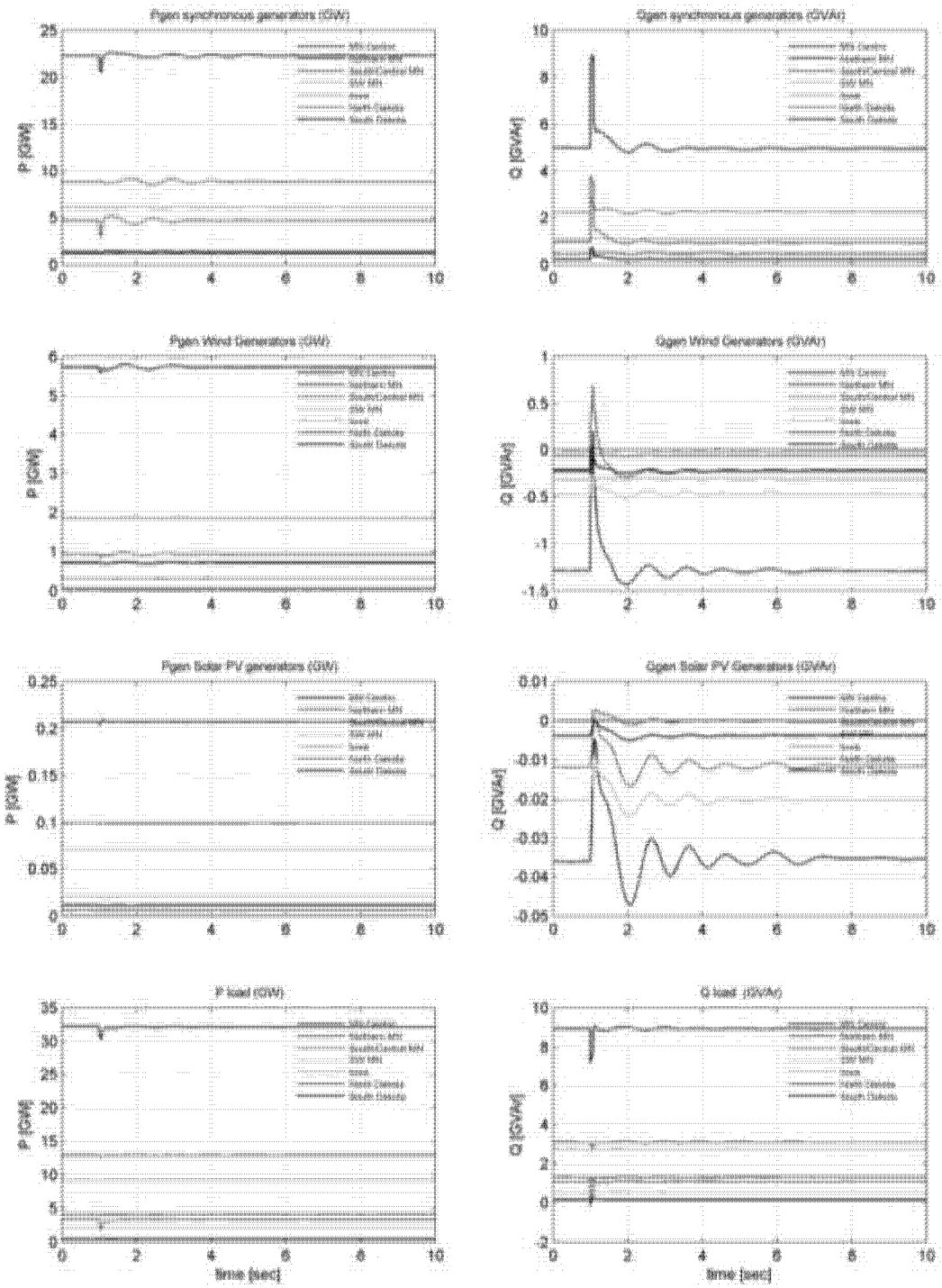

Figure 8-12 Case 3: AG3 fault Active and Reactive Response

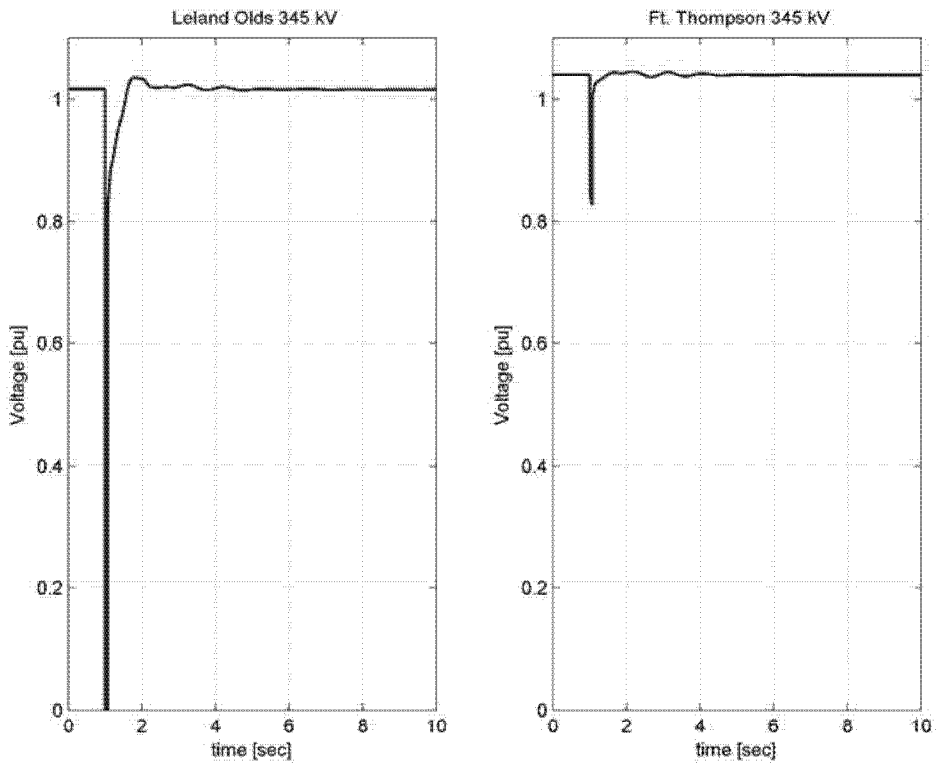

Figure 8-13 Case 3: AG3 fault Voltage Magnitude

8.2.4 High %RE conditions

The case developed to reflect high percentage of renewable penetration in Minnesota footprint is case 4. This is a light load case representing dispatch in early October during night hours between 12am and 7am. The fault selected is NAD fault (4cycles 3 phase fault on the Dorsey to Forbes 500 kV line D602F at Forbes. Runback bi-poles that terminate at Dorsey). Minnesota footprint generation and load response to a NAD fault is presented in Figure 8-14. Voltage recovery at 500 kV buses

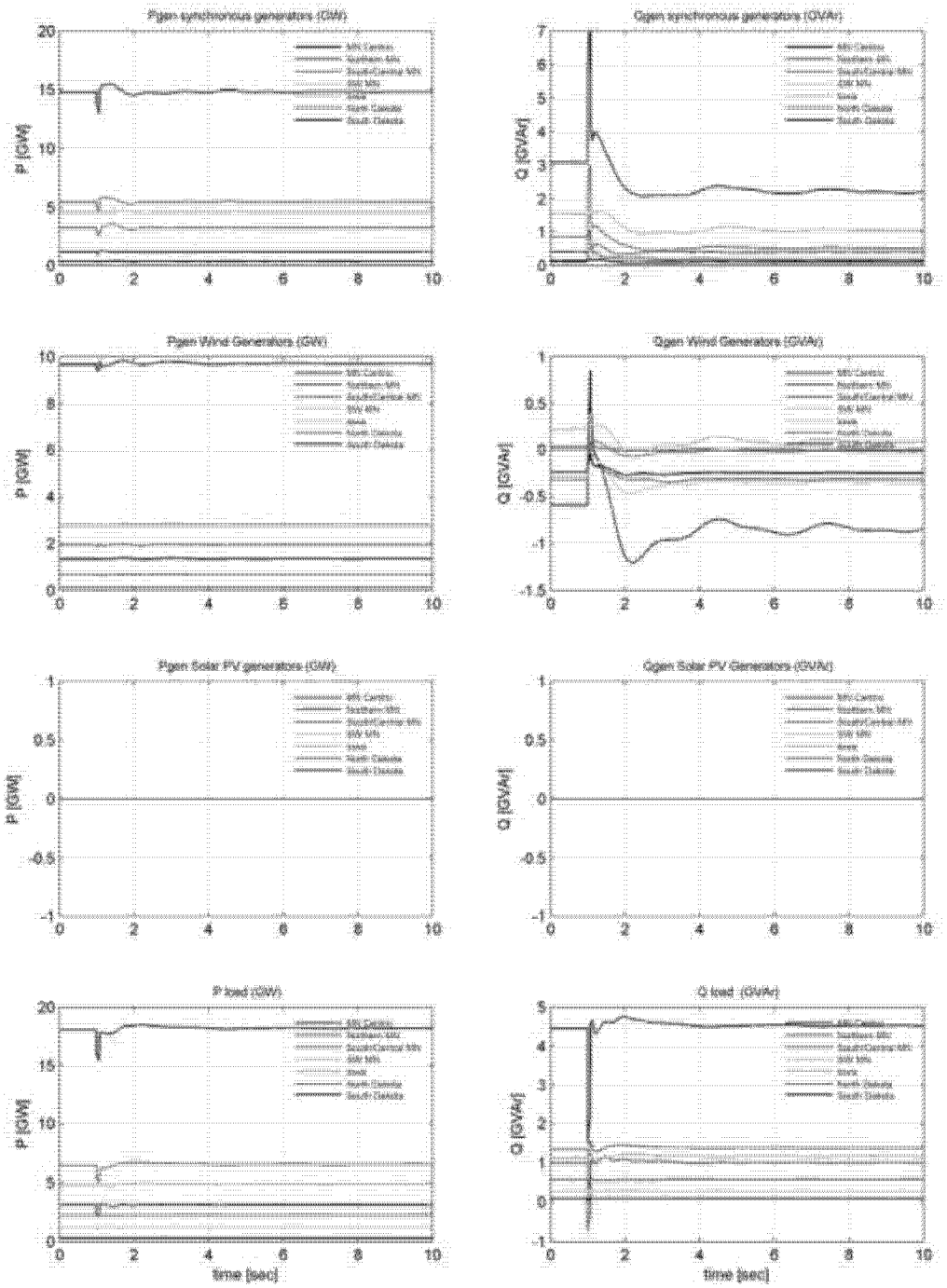

Figure 8-14 Case 4: NAD fault Active and Reactive Response

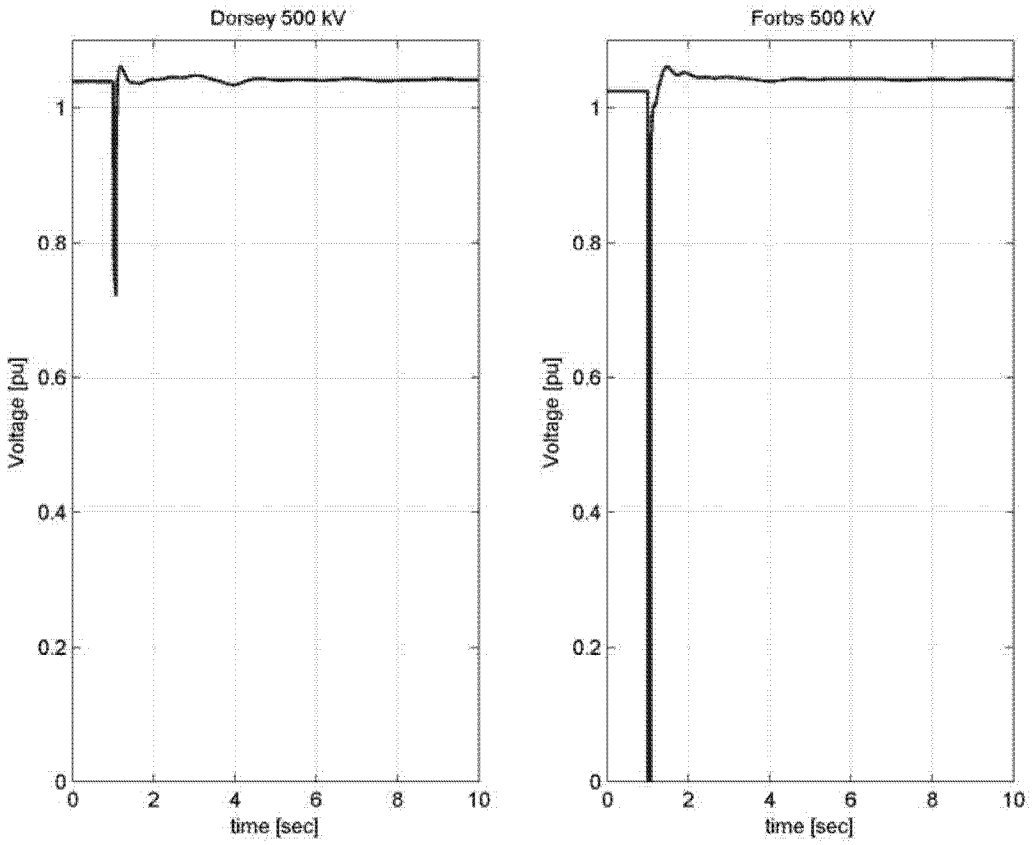

Figure 8-15 Case 4: NAD fault Voltage Magnitude

8.2.5 High Transfer Conditions

The case developed to reflect high transmission loading on NDEX, Buffalo Ridge Outlet and MWEX interfaces are case 5, case 6 and case 7 respectively. The faults selected to represent system response on these cases are:

1. Case 5: AG1_v2 (Single-line-to-ground fault with breaker fail at Leland Olds on the Groton 3 345 kV line)
2. Case 6: SHEAS (Three-phase fault at SHEAS LK3 on the HELENA 3 345 kV line. Clear both ends of the line in 4 cycles)
3. Case 7: BRIGS (Three-phase fault at Briggs on the NMA 345 kV line. Clear both ends of the line in 4 cycles)

Plots of Minnesota footprint area generation and load response as well as post fault voltage recovery is presented in Figure 8-16 through Figure 8-21.

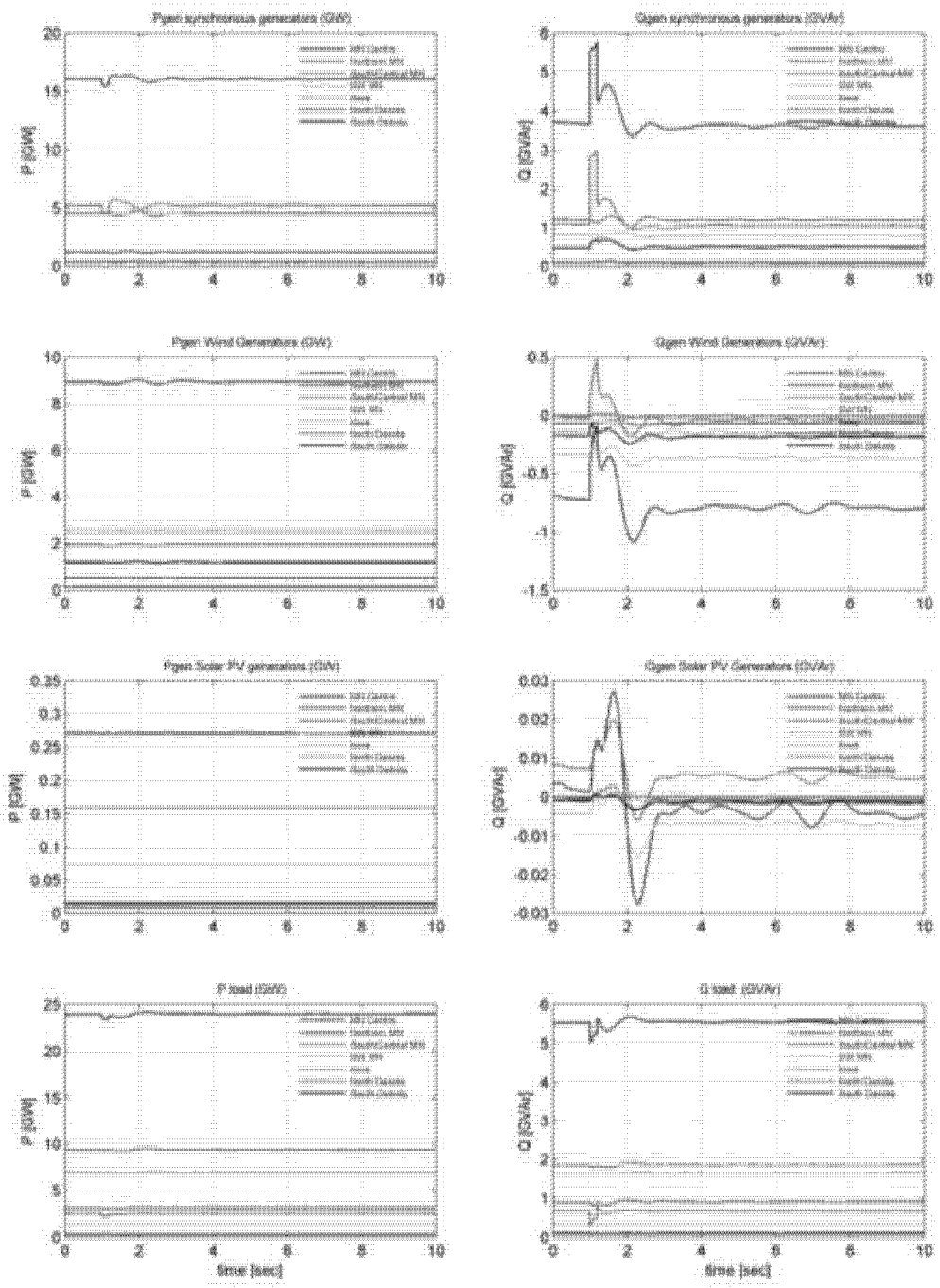

Figure 8-16 Case 5: AG1_v2 fault Active and Reactive Response

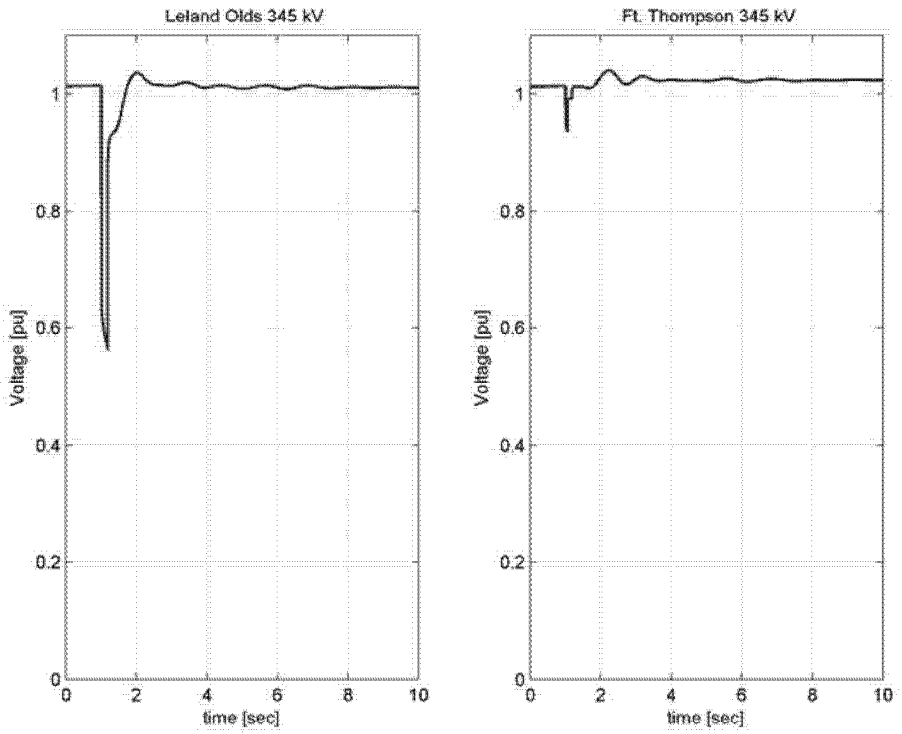

Figure 8-17 Case 5: AG1_v2 fault Voltage Magnitude

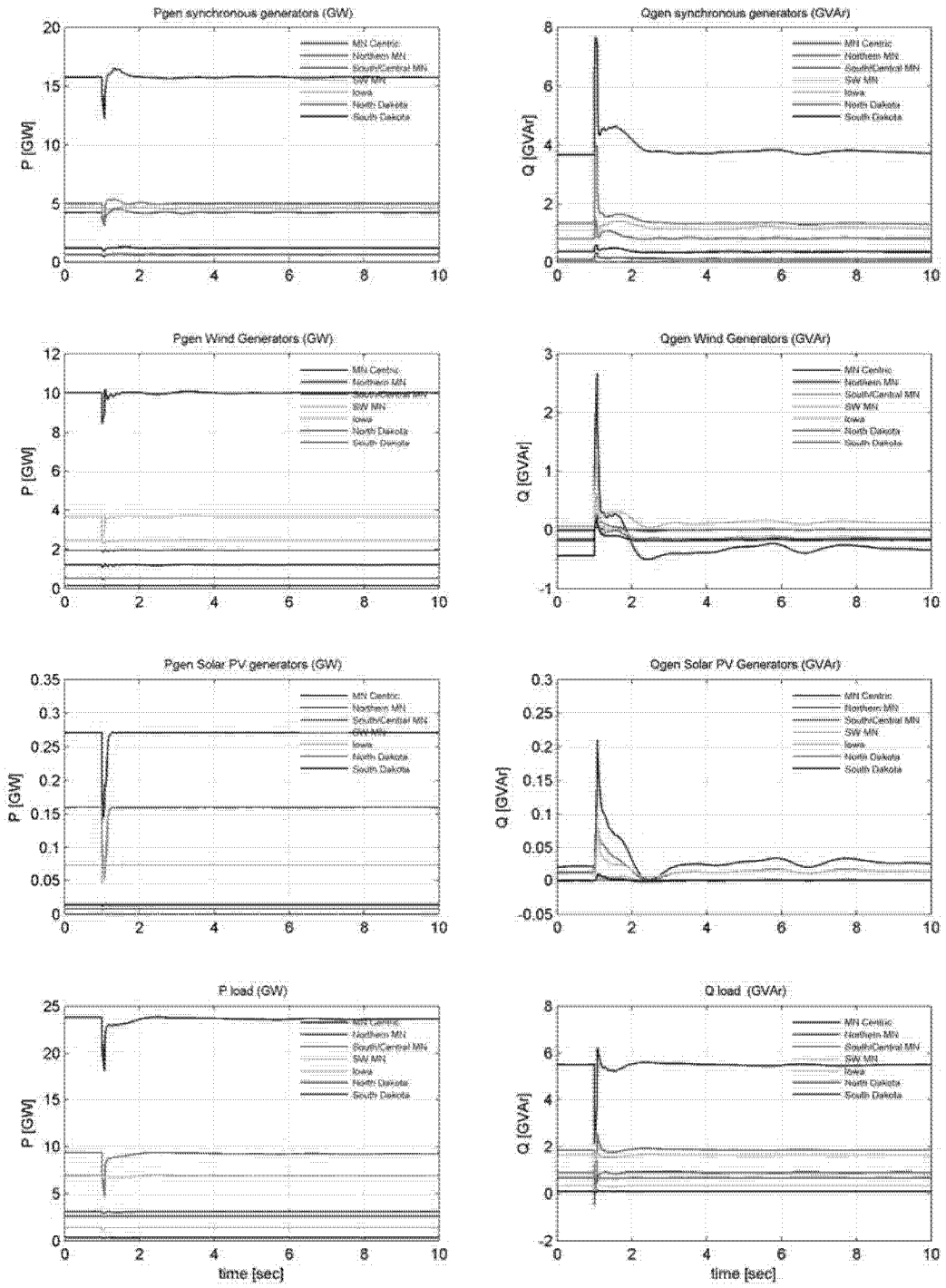

Figure 8-18 Case 6: SHEAS fault Active and Reactive Response

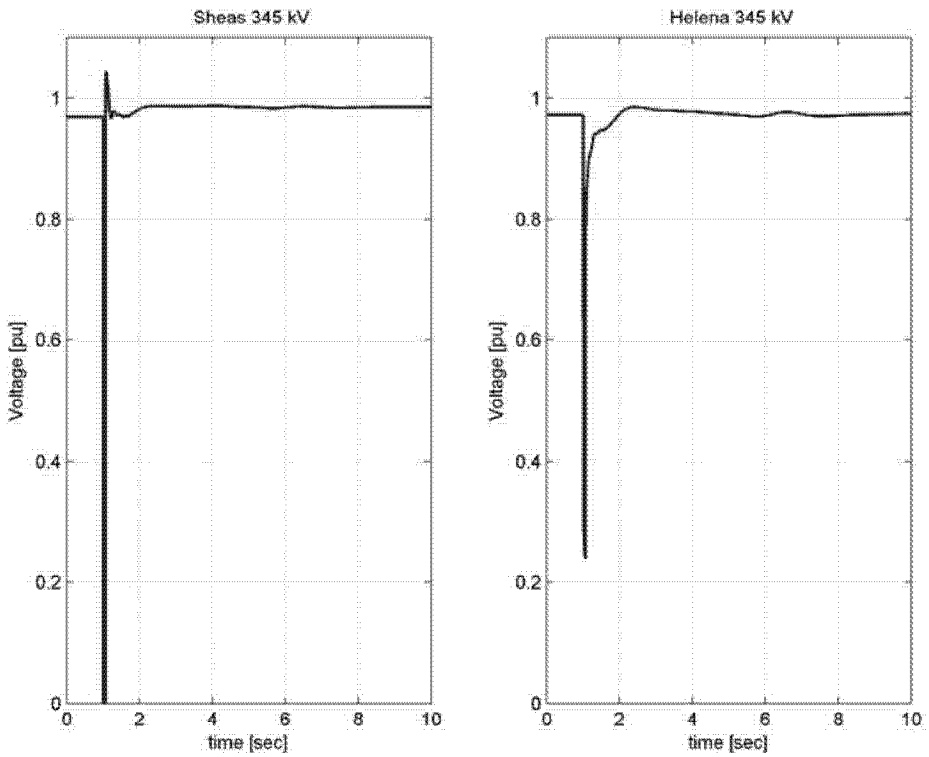

Figure 8-19 Case 6: SHEAS fault Voltage Magnitude

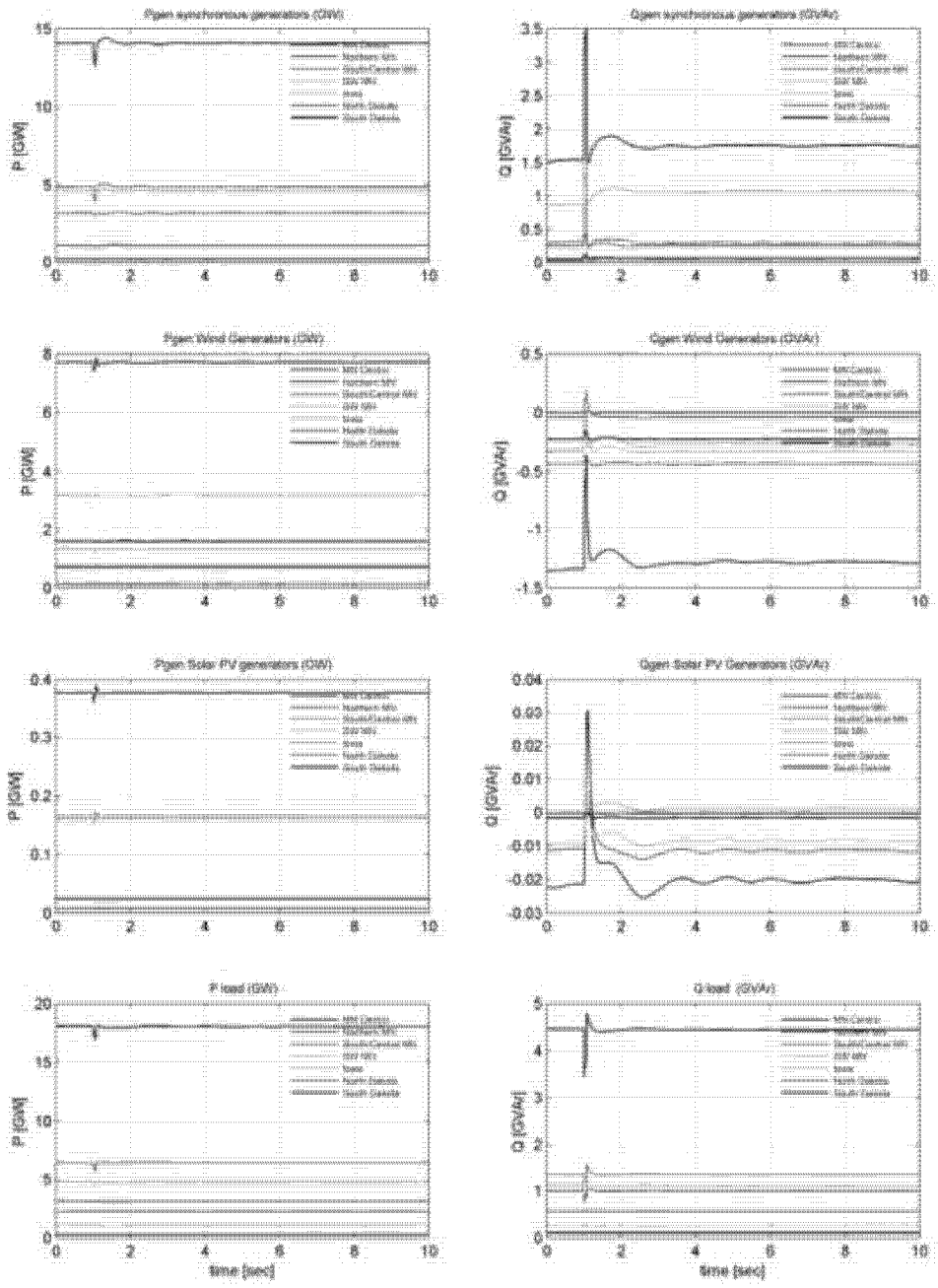

Figure 8-20 Case 7: BRIGGS fault Active and Reactive Response

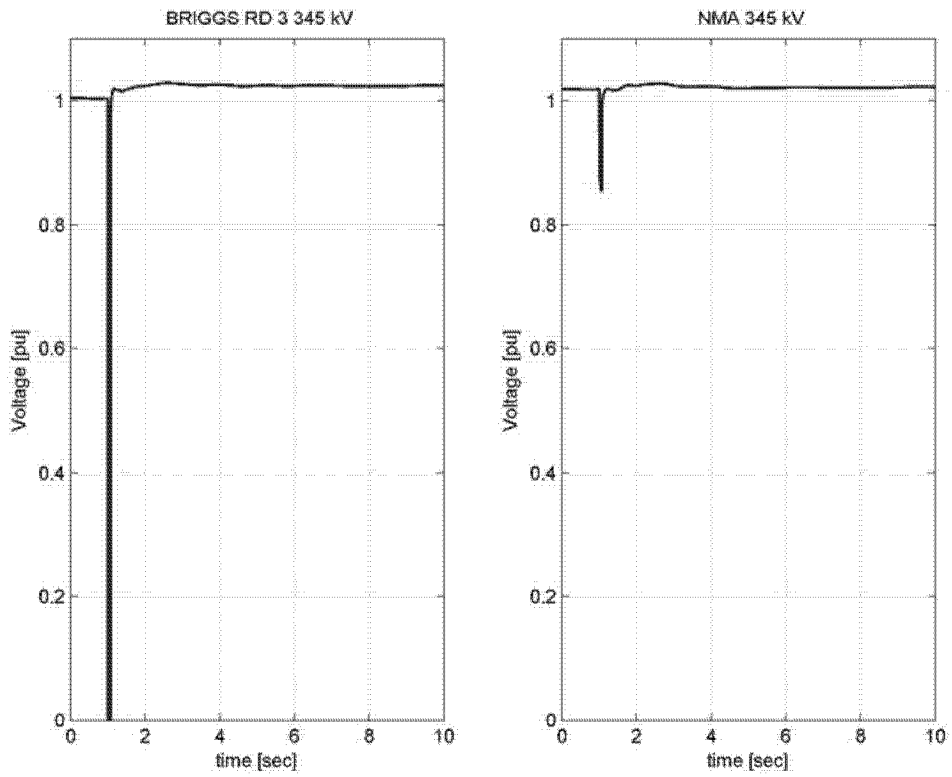

Figure 8-21 Case 7: BRIGGS fault Voltage Magnitude

8.3 Reactive Reserves

The dynamic reactive reserves for all test cases (plotted in Figure 8-7) were sufficient to maintain system stability and allow for acceptable voltage recovery. Both the transient voltage dip and post-transient voltages recovered met all screening criteria.

Sensitivity analysis was performed on two areas to test the response with lower dynamic reactive reserves. The first sensitivity was performed on a localized load pocket. When developing the power flow cases, low voltage and power flow convergence issues were observed in the Tac Harbor / Silver Bay area of Northern Minnesota. This area has a significant amount of industrial load, including over 75 MW of large synchronous motor load. Some of the production simulation hours had all Silver Bay and Tac Harbor units turned off. In most cases, the power flow failed to converge with these units turned off. If the power flow did solve with the generators off, voltages were well below 1.0 pu.

With all local generation off line, the Tac Harbor synchronous motors will be dynamically unstable for faults in the area. Turning on some units, either as generators or synchronous condensers will stabilized the motors. Though not tested, it is likely that new transmission and/or a static var compensator (SVC) would also stabilize the motors.

The second sensitivity was performed on the Manitoba Hydro (MH) HVDC ties and the 500 kV lines from MH to Minnesota. The 2028 power flow cases modeled a new HVDC tie into the Riel station along with reinforcements to the existing 500 kV system near the Iron Range. These reinforcements are intended to support higher MH exports. The HVDC inverter stations at Dorsey and Riel have several synchronous condensers to provide short circuit strength and reactive support. The S1_SH_D01 case has 2975 MW of MH exports. As noted above, all test disturbances are stable with acceptable post-fault voltage recovery for all of the test cases.

Several sensitivity simulations were performed on the shoulder load case (S1_SH_D01) with the Riel condensers turned off and the Dorsey condensers modeled with fixed field voltage. Modeling the Dorsey condensers with fixed field voltages allowed them to provide short circuit strength but not regulate voltages. Under these sensitivity test conditions, faults in Central Minnesota on the Terminal-King line caused a wide-spread instability. In order to stabilize this case, the MH exports had to be reduced by more than 500 MW.

This sensitivity analysis showed that localized dynamic reactive power support is critical to maintaining system stability. The current plans, as modeled in this study, address this issue and are sufficient for the anticipated levels of MH exports. The current practice of operating the Silver Bay and/or Tac Harbor generators to support the local industrial load provides strong local area voltage.

8.4 Weak Grid Analysis

As wind penetration increases and market commitment of synchronous resources decreases, there is a point where the grid is no longer strong enough (i.e. the impedance is too high) to support stable operation of the power electronic converters within the wind generators and PV plants. This can happen for single machines as well as for groups of machines in a wind plant and groups of wind plants in a region.

This is an emerging issue. Very few systems have faced this issue in actual operation (e.g. a few events in Texas before the transmission system was reinforced). Very few transmission engineers understand this issue in depth, as it has its roots within the lowest-level internal controllers of the wind and solar power electronic converter equipment. Knowledge of this issue is built upon converter performance tests and detailed analysis using transient simulation tools such asPower Systems Computer Aided Design (PSCAD) and ElectroMagnetic Transients Program (EMTP). Since such tools and analytical methods are not well suited to studying large-scale risks for many plants over wide geographic areas, the challenge is to take what is learned from detailed analysis of a few plants and extend that learning across larger regions using more practical methods.

8.4.1 Composite Short Circuit Ratio Concepts

Short Circuit Ratio (SCR) is a method used to screen for weak grid conditions near power electronic converters. This method has been used for decades to screen for weak grid conditions near HVDC converters and is currently being applied to wind plants. SCR is the ratio of the available system strength (measured in short circuit MVA) to the MW rating of the wind or PV plant.

While SCR is well established and trusted for HVDC and single-plant wind projects, it is not well suited for areas with multiple wind and solar plants in close proximity. For such cases, the industry is moving towards the Composite Short Circuit Ratio (CSCR) of all plants together.

Like SCR, this is the ratio of available short circuit MVA to plant MW rating. However, it accounts for multiple nearby plants by taking the ratio of composite short circuit MVA to that total MW rating of all plants.

The composite short circuit MVA is calculated by tying together the buses at the low side of the interconnection transformers of all wind and/or PV plants, creating a "composite" bus. The short circuit MVA is then calculated at the composite bus through normal fault calculation methods. CSCR is the ratio of the composite short circuit MVA to the total MW rating of all the wind and PV plants. This is shown in Figure 8-22. The wind and PV plants are assumed to have no fault current contribution when calculating CSCR.

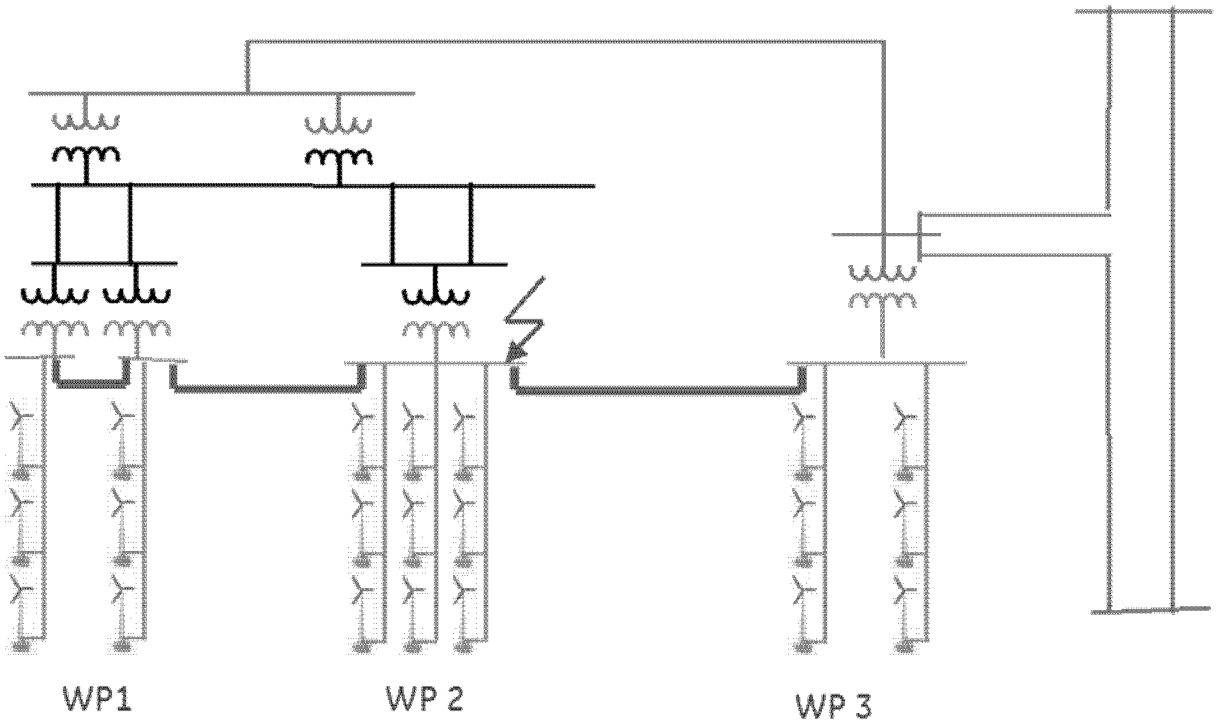

Figure 8-22 Example of composite, short-circuit MVA at Multiple Wind Plants

CSCR is calculated for normal and contingency conditions and considers generation off line. Unlike normal fault calculations, where the object is to determine the strongest system condition and highest fault current, CSCR calculations are intended to determine the weakest conditions the wind and PV will be expected to operate under.

Based on current wind turbine generator technology, a system with a CSCR above about 2.5 to 3 is considered strong. The wind plants should not have control instability issues. CSCR below about 1.7 to 1.5 is considered weak. CSCR below 1.0 would likely require mitigation, either at the plant through control tuning, by strengthening the system (e.g. new transmission or synchronous machines) or a combination of both. There is less experience with an acceptable CSCR level for PV plants.

8.4.2 Identifying Weak Regions

One of the challenges in evaluating weak grid issues for this study was identifying regions of the Minnesota system and the groups of wind and PV plants within those regions that could have low CSCR. The approach used for this analysis was to find relatively weak regions where voltage regulation was impacted more by wind and PV than by synchronous generation.

A measure of voltage regulation ratio was developed as the ratio of Thevenin impedance looking into the terminals of all synchronous generation to the Thevenin impedance looking into the terminals of all wind and PV generation. The Thevenin impedance was calculated taking the MVA rating of each unit into account. A low Thevenin impedance indicates a bus with strong voltage regulation and a high impedance indicates less voltage regulation. Since the voltage regulation ratio was defined as synchronous to non-synchronous Thevenin impedance, a ratio greater than 1.0 points to a bus with higher control from wind and PV than from synchronous generation. This corresponds to the regional measure of %NS, but on a substation level.

The voltage regulation ratio was calculated at all 230 kV and above Minnesota-centric buses. The total short circuit MVA was also calculated at the same buses. These two measures were then plotted for all buses and used to identify possible weak system areas with high renewables. This is shown in Figure 8-23. Each point in the plot represents a transmission bus, color coded by the six Minnesota-centric sub-regions. This plots is for n-0 transmission condition for the shoulder load case 1 dispatch (S1_SH_D01), as this cases had the overall highest percent non-synchronous generation.

Three clusters of buses are highlighted on the plot. Quad Cities 345 kV bus has 16,000MVA of short circuit strength and a voltage regulation ratio less than 0.5. This is to be expected, since both Quad Cities nuclear generating units are in service and dominate the voltage regulation at the transmission bus.

The Ashtabula plant in North Dakota is fed from Pillsbury 230 kV, near Fargo. This group of 230 kV buses, highlighted in the upper left corner of the plot, has a voltage regulation ratio above 3.0 and 710 MVA of short circuit strength. This is clearly a system dominated by wind generation with little short circuit strength. The three Ashtabula wind sites have a total capacity of 377 MW. This gives a CSCR of 1.88 under n-0 transmission conditions (710MVA/377MW). This is in the range of concern, particularly since the CSCR would likely be lower with transmission outages.

The transmission buses in SW Minnesota are shown with orange circles. Four 345 kV buses are highlighted; Obrien, Nobles, Huntley and Lakefield. These buses have a relatively high short circuit strength (5000 to 7000 MVA), but also have a high voltage regulation ratio (1.5 to 2.0). These buses are in the Buffalo Ridge area. The high voltage regulation ratio is due to the large amount of renewables in SW Minnesota (4344 MW total for S1). The short circuit strength is due to the strong 345 kV transmission around the area, connecting it to synchronous generation to the west, south and east. System strength and CSCR calculations in this region are presented in the next section.

The analysis was also used to identify additional contingencies for the stability analysis. Critical transmission lines were identified based on initial loading (i.e. power flow in the base condition) and on the fault current contribution for faults on 345 kV buses around the Buffalo Ridge area. Tripping transmission lines that provide the highest fault current and have the highest initial loading will be

most challenging from a weak-system and a transient disruption standpoint. Outages identified from the weak system analysis are identified as LSC1 through LSC5, and SHEAS in Table 8-2.

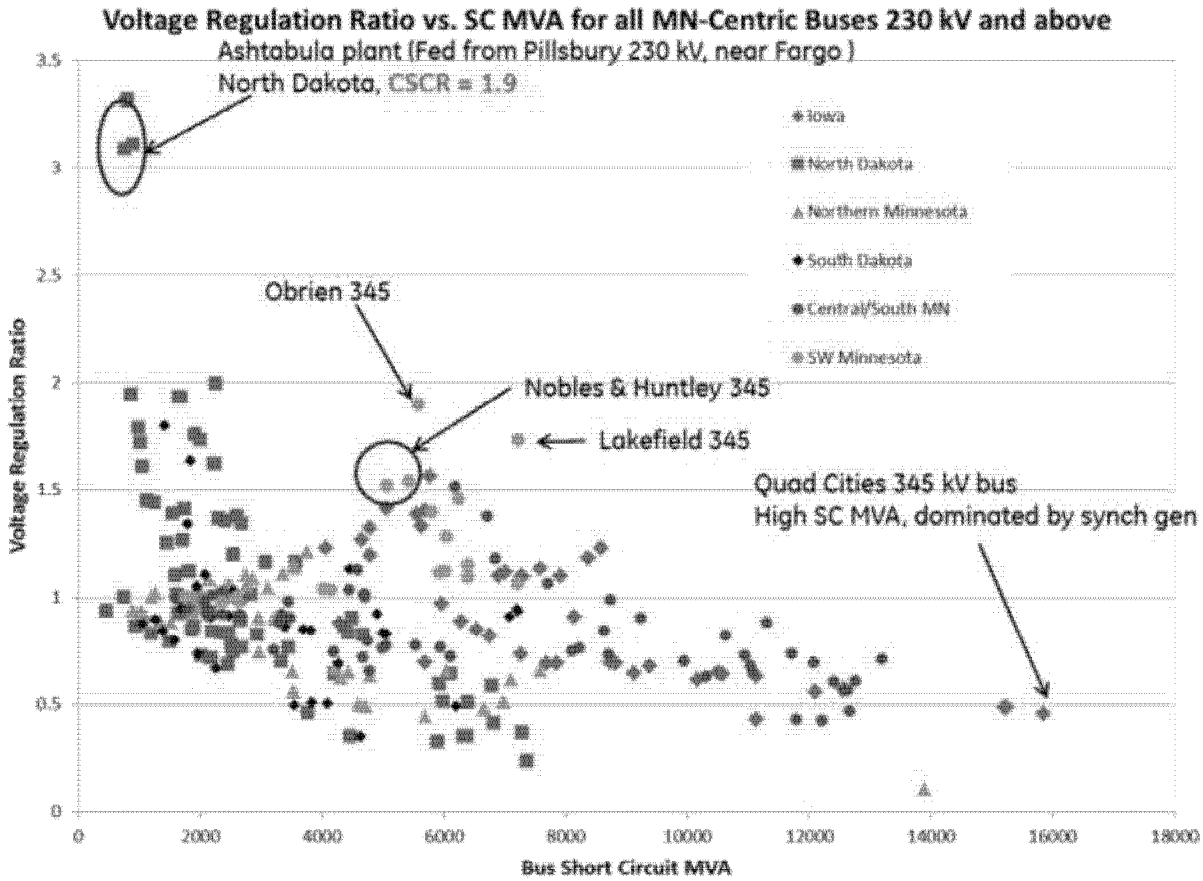

Figure 8-23 SC MVA vs. Voltage Regulation Ratio for Minnesota-Centric Transmission Buses

8.4.3 Southwestern Minnesota CSCR

As discussed above, the SW Minnesota region has a high concentration of renewable generation and relatively high short circuit strength under normal operating conditions. In total, the region has 4344 MW of renewable generation capacity for the S1 system. The rated MW of each plant in this area is listed in Table 8-4. New PV and New Wind represent renewable generation added for the baseline and S1 scenarios.

The CSCR for the composite of all of the SW Minnesota renewable generation was calculated by tying the low side of the interconnection transformers together with all renewable generation disconnected. For the S1_SH_D01 case, the CSCR is 9040 MVA over 4344 MW, or 2.08. This is in the caution region.

The CSCR was calculated with generation throughout the Minnesota-centric region decommitted. In general, no single generator had a significant impact on CSCR. The greatest reduction was seen for decommitting both Prairie Island units (two 659 MVA nuclear units northeast of Buffalo Ridge).

With both of these units off line, CSCR drops to from 2.08 to 2.00. Decommitting Neal 4 (711 MVA unit near Buffalo Ridge) reduced CSCR to 2.04.

Other decommitted units evaluated include Streeter, Ames, Coal Creek, Big Stone, Willmar, Heskett, JP Madgett, Stanton and King. These units were selected based on their commitment across all six stability cases and their operation in all of the selected hours. With all of these units off line, CSCR drops from 2.08 to 1.99. This is not a significant drop in CSCR, given the number of units decommitted. Sensitivity analysis was conducted where Hydro units at Garrison, Big Bend and Oahe were decommitted. These units had very little measurable impact on CSCR in the SW Minnesota region.

Transmission outages play a larger role in CSCR than individual generator status. Loss of the Sheas Lake to Helena 345 kV lines decreases the CSCR from 2.08 to 1.90. All other transmission outages tested has much less impact on CSCR. For example, loss of the Nobles-Lakefield or White-Split Rock 345 kV lines will only reduce the CSCR from 2.08 to 2.07. Several other transmission contingencies were studied but none had a significant impact on CSCR.

8.4.4 Mitigation through Wind/PV Inverter Controls

Standard inverter controls and setting procedures may not be sufficient for weak system applications. Loop gains of internal control functions inherently increase when system impedance increases, thereby reducing the stability margin of the controllers. Developers and equipment vendors must be made aware when new plants are being proposed for weak system regions so they can design/tune controls to address the issue. Wind plant vendors have made significant progress in designing wind and solar plant control systems that are compatible with weak system applications.

This approach becomes somewhat more difficult when there are wind/solar plants from multiple vendors in one region. The level of analysis requires detailed modeling of all affected wind plants at a level of detail that requires the use of proprietary control design information from the vendors. Vendors are very reluctant to share such data, except with independent consultants who can guarantee strict data security. However, this approach is gaining traction and a few projects have made effective implementations. The key to success is that project developers and equipment vendors must be informed beforehand that a given wind or solar plant will be installed at a weak system location. This enables the appropriate control design studies to be initiated before the project is installed.

In the event that such control-based approaches are not sufficient, it would be possible to further improve weak system performance by employing one or more of the system-level mitigations discussed below.

8.4.5 Low CSCR Mitigation

Committing additional generation will increase CSCR, but the increase is not drastic unless large blocks of units are put on line. For example, committing all coal units rated above 50 MVA in the MN centric footprint (7160 MVA total) increases the CSCR from 2.08 to 2.18. This is a very modest increase for such a large amount of committed generation. Therefore, mitigating low CSCR issues through commitment of existing generation is not a reasonable solution.

Two more reasonable methods available to increase CSCR in SW Minnesota are:

1. Add new synchronous machines, either generators or condensers, in the SW Minnesota region.
2. Lower the impedance between the region and the surrounding synchronous generation through new transmission, new 345/115 kV transformers or lower impedance transformers at the renewable generation sites.

Analysis considered the impact of adding synchronous condensers at several 345 kV and 115 kV buses in the Buffalo Ridge region.

Synchronous condensers are synchronous machines that have the same voltage control and dynamic reactive power capabilities as synchronous generators. Synchronous condensers are not connected to prime movers (e.g. steam turbines or combustion turbines), so they do not generate power.

Adding the condensers at the 115 kV level had the greatest increase in CSCR, since they were placed electrically closer to the renewable sites than on the higher voltage buses. For example, adding a 500 MVA of synchronous condensers at Lyon Co 115 kV and another 500 MVA at Nobles 115 kV increased the CSCR to 2.4. Moving the condensers to the 345 kV buses had a much lower improvement in CSCR.

Adding new transmission, particularly in the Sheas Lake area, will increase CSCR. Similarly, lower impedance transformers on the grid or in the renewable plants will increase CSCR. However, the benefits are likely to be modest.

Table 8-4 S1 Renewable Generation in SW Minnesota (Total MW Rating)

Sum of Pmax	S1_LL_D02	S1_LL_D04	S1_PK_D03	S1_SH_D01
PV	**160**		**160**	**160**
New PV	160		160	160
WIND	**4076**	**4184**	**4184**	**4184**
BRI3	290	290	290	290
BVIS		108	108	108
CHB3	281	281	281	281
CWS1	16	16	16	16
CWS2	14	14	14	14
DANJ	12	12	12	12
ELMC	151	151	151	151
ERID	10	10	10	10
G162	200	200	200	200
G164	200	200	200	200
G176	100	100	100	100
G255	100	100	100	100
G298	100	100	100	100
G358	35	35	35	35
G375	20	20	20	20
G426	150	150	150	150
G586	30	30	30	30
GRE-	227	227	227	227
JEFF	50	50	50	50
JHND	28	28	28	28
MMU	19	19	19	19
NOB_	200	200	200	200
ODIN	20	20	20	20
SRID	5	5	5	5
UILK	5	5	5	5
WEST	8	8	8	8
New Wind	1781	1781	1781	1781
WOLF	7	7	7	7
WOOD	10	10	10	10
WRID	7	7	7	7
Grand Total	**4236**	**4184**	**4344**	**4344**

9 KEY FINDINGS

This study examined two levels of increased wind and solar generation for Minnesota; 40% (represented by Scenarios 1 and 1a) and 50% (represented by Scenarios 2 and 2a). In the 40% Minnesota Scenario, MISO North/Central is at 15% (current state RESs). The 50% Minnesota Scenario also included an increase of 10% (to 25%) in the MISO North/Central region. Production simulation was used to examine annual hourly operation of the MISO North/Central system for all four of these scenarios. Transient and dynamic stability analysis was conducted for Scenarios 1 and 1a but not on Scenarios 2 and 2a.

9.1 General Conclusions for 40% RE Penetration in Minnesota

With wind and solar resources increased to achieve 40% renewable energy for Minnesota and 15% renewable energy for MISO North/Central, production simulation and transient/dynamic stability analysis results indicate that the system can be successfully operated for all hours of the year with no unserved load, no reserve violations, and minimal curtailment of renewable energy. This assumes sufficient transmission mitigations, as described in Chapter 4, to accommodate the additional wind and solar resources.

This is operationally achievable with most coal plants operated as baseload must-run units, similar to existing operating practice. It is also achievable if all coal plants are economically committed per MISO market signals, but additional analysis would be required to better understand implications, tradeoffs, and mitigations related to increased cycling duty.

Dynamic simulation results indicate that there are no fundamental system-wide dynamic stability or voltage regulation issues introduced by the renewable generation assumed in Scenario 1 and 1a. This assumes:

- New wind turbine generators are a mixture of Type 3 and Type 4 turbines with standard controls
- The new wind and utility-scale solar generation is compliant with present minimum performance requirements (i.e. they provide voltage regulation/reactive support and have zero-voltage ride through capability)
- Local-area issues are addressed through normal generator interconnection requirements

9.2 General Conclusions for 50% RE Penetration in Minnesota

With wind and solar resources increased to achieve 50% renewable energy in Minnesota and 25% renewable energy in MISO, production simulation results indicate that the system can be successfully operated for all hours of the year with no unserved load, no reserve violations, and minimal curtailment of renewable energy. This assumes sufficient transmission upgrades, expansions and mitigations to accommodate the additional wind and solar resources.

This is operationally achievable with most coal plants operated as baseload must-run units, similar to existing operating practice. It is also achievable if all coal plants are economically committed per MISO market signals, but additional analysis would be required to better understand implications, tradeoffs, and mitigations related to increased cycling duty.

No dynamic analysis was performed for the study scenarios with 50% renewable energy for Minnesota (Scenarios 2 and 2a) due to study schedule limitations and this analysis is necessary to ensure system reliability.

9.3 Annual Energy in the Minnesota-Centric Region

Figure 9-1 shows the annual load and generation energy by type for the Minnesota-Centric region. Comparing Scenarios 1 and 1a (40% MN renewables) with the Baseline,

- Wind and solar energy increases by 8.5 TWh, all of which contributes to bringing the State of Minnesota from 28.5% RE penetration to 40% RE penetration
- There is very little change in energy from conventional generation resources
- Most of the increase in wind and solar energy is balanced by a decrease in imports. The Minnesota-Centric region goes from a net importer to a net exporter.

Comparing Scenarios 2 and 2a (50% MN renewables) with Scenarios 1 and 1a (40% MN renewables),

- Wind and solar energy increases by 20 TWh. Of this total, 4.8 TWh brings the State of Minnesota from 40% to 50% RE penetration and the remainder contributes to bringing MISO from 15% to 25% RE penetration
- Most of the increase in wind and solar energy in the Minnesota-Centric region is balanced by a decrease in coal generation and an increase in net exports to neighboring regions
- Gas-fired, combined-cycle generation declines from 5.0 TWh in Scenario 1 to 3.0 TWh in Scenario 2.

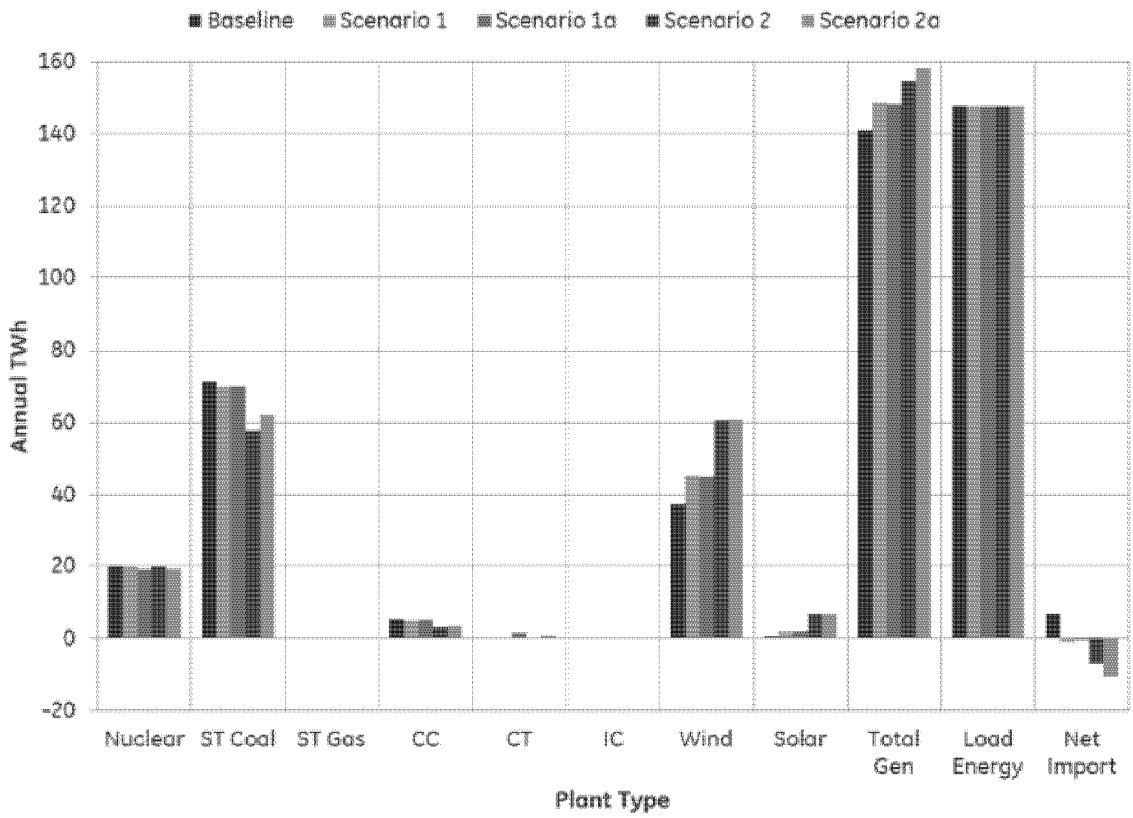

Figure 9-1 Annual Energy by Type in Minnesota-Centric Region for Study Scenarios

9.4 Cycling of Thermal Plants

Most coal plants were originally designed for baseload operation; that is, they were intended to operate continuously with only a few start/stop cycles in a year (mostly due to scheduled or forced outages). Increased cycling duty could increase wear and tear on these units, with corresponding increases in maintenance requirements. Many coal plants in MISO presently are designated by the plant's owner to operate as "must-run" in order to avoid start/stop cycles that would occur if they were economically committed by the market.

Scenarios S1a and S2a assumed that all coal plants in MISO are subject to economic commitment/dispatch (i.e., not must-run) based on day-ahead forecasts of load, wind and solar energy within MISO. Production simulation results show significant coal plant cycling due to economic market signals:

- Small coal units (below 300 MW rating) could have an additional 100 to 200 starts per year, beyond those due to forced or planned outages.
- Large coal units (above 300 MW) could have an additional 20 to 100 starts per year

Scenarios S1 and S2 assumed almost all coal plants would continue to operate as they do today. Coal units were on-line all year (except for scheduled maintenance periods) and were not decommitted during periods of low market prices. The results of these scenarios confirmed that the coal units could remain must-run with minor impacts on overall operation of the Minnesota-Centric

region. Coal plant owners could choose to continue the must-run practice to avoid the detrimental impacts of increased cycling as wind and solar penetration increases. Doing so would likely incur some additional operational costs when energy prices fall below a plant's breakeven point. Wind curtailment would also be about 0.5% higher than if the coal plants were economically committed.

An attractive solution to the coal plant cycling issue may exist between the two bookend cases analyzed in this study. Scenarios 1a and 2a assumed that unit commitment was determined on a day-ahead basis, using day-ahead forecasts of wind and solar energy. The result was a high number of start/stop cycles of coal plants, sometimes with down-times of less than 2 days. If the unit commitment process was modified to use a longer term forward market (say 3 to 5 days ahead), then coal plant owners could adjust their operational strategy to consider decommitting units when prolonged periods of high wind/solar generation and low system loads are forecasted. A forward market would depend on longer term forecasts of wind, solar and load energy, consistent with the look-ahead period of the market. Although such forecasts would be somewhat less accurate than day-ahead forecasts, the quality of the forecasts would likely be adequate to support such unit commitment decisions.

This study did not examine the economic or wear-and-tear impacts of increased cycling on coal units. Further information on this topic can be found in the NREL Western Wind and Solar Integration Study Phase 2 report[1] and the PJM Renewable Integration Study report[2].

Combined-cycle (CC) units are better able to accommodate cycling duties than coal plants. Simulation results show that combined cycle units in the Minnesota-Centric region experience from 50 to 200 start/stop cycles per year. Cycling of CC units declines slightly as wind and solar penetration increases. This decline is primarily due to a decrease in CC plant utilization as wind and solar energy increases.

9.5 Curtailment of Wind and Solar Energy

In general, a small amount of curtailment is to be expected in any system with a significant level of wind and solar generation. There are some operating conditions where it is economically efficient to accept a small amount of curtailment (i.e., mitigation of that curtailment would be disproportionately expensive and not justifiable).

Overall curtailment in the Minnesota-Centric region is relatively small in all study scenarios, as shown in Table 9-1. Wind curtailment in Baseline and Scenario 1 is primarily due to local transmission congestion at a few wind plants. This congestion could be mitigated by transmission modifications, if economically justifiable.

Wind curtailment in Scenario 2 is due to system-wide operational limits during nighttime hours, when many baseload generators are dispatched to their minimum output levels. This type of curtailment could be reduced by decommitting some baseload generation via economic market signals. The effectiveness of this mitigation option is illustrated by comparing Scenario 2 (coal units must-run) with Scenario 2a (economic coal commitment). Wind curtailment decreases from 2.14% to 1.60% (reduction of 332 GWh of wind curtailment). Solar curtailment decreases from 0.42% to 0.24% (reduction of 12 GWh of solar curtailment).

[1] http://www.nrel.gov/electricity/transmission/western_wind.html
[2] http://www.pjm.com/committees-and-groups/task-forces/irtf/pris.aspx

Table 9-1 Wind and Solar Curtailment for Study Scenarios

Scenario	Baseline	Scenario 1	Scenario 1a	Scenario 2	Scenario 2a
Wind Curtailment	0.42%	1.00%	1.59%	2.14%	1.60%
Solar Curtailment	0.09%	0.00%	0.23%	0.42%	0.24%

Note: Curtailment is calculated as a percentage of available annual wind or solar energy.

9.6 Other Operational Issues

No significant transmission system congestion was observed in any of the study scenarios with the assumed transmission upgrades and expansions. Transmission contingency conditions were considered in both the powerflow analysis used to develop the conceptual transmission system and the security-constrained economic dispatch in the production simulation analysis.

Ramp-range-up and ramp-rate-up capability of the MISO conventional generation fleet increases with increased penetration of wind and solar generation. Conventional generation is generally dispatched down rather than decommitted when wind and solar energy is available, which gives those generators more headroom for ramping up if needed.

Ramp-range-down and ramp-rate-down capability of the MISO conventional generation fleet decreases with increased penetration of wind and solar generation. In Scenario 2, there are 500 hours when ramp-rate-down capability of the conventional generation fleet falls below 100 MW/min. Periods of low ramp-down capability coincide with periods of high wind and solar generation. Wind and solar generators are capable of providing ramp-down capability during these periods. MISO's existing Dispatchable Intermittent Resource (DIR) process already enables this for wind generators. It is anticipated that MISO would expand the DIR program to include solar plants in the future.

9.7 System Stability, Voltage Support, Dynamic Reactive Reserves

No angular stability, oscillatory stability or wide-spread voltage recovery issues were observed over the range of tested study conditions. The 16 dynamic disturbances used in stability simulations included key traditional faults/outages as well as faults/outages in areas with high concentrations of renewables and high inter-area transmission flows. System operating conditions included light load, shoulder load and peak load cases, each with the highest percent renewable generation periods in the Minnesota-Centric region.

Overall dynamic reactive reserves are sufficient and all disturbances examined for Scenarios 1 and 1a show acceptable voltage recovery. The South/Central and Northern Minnesota regions get the majority of their dynamic reactive support from synchronous generation. Maintaining sufficient dynamic reserves in these regions is critical, both for local and system-wide stability.

Southwest Minnesota, South Dakota and at times Iowa get a significant portion of dynamic reactive support from wind and solar resources. Wind and Solar resources contribute significantly to voltage support/dynamic reactive reserves. The fast response of wind/solar inverters helps voltage recovery following transmission system faults. However, these are current-source devices with little or no overload capability. Their reactive output decreases when they reach a limit (low voltage and high current).

Synchronous machines (either generators or synchronous condensers), on the other hand, are voltage-source devices with high overload capability. This characteristic will strengthen the system voltage, allowing better utilization of the dynamic capability of renewable generation. The mitigation methods discussed below, namely stiffening the ac system through new transmission or synchronous machines, will also address this concern.

Local load areas, such as the Silver Bay and Taconite Harbor area, require reactive support from synchronous machines due to the high level of heavy industrial loads. If all existing synchronous generation in this region is off line (i.e. due to retirement or decommitment), reinforcements such as new transmission or synchronous condensers would be required to support the load.

Dynamic simulation results indicate that it is critical to maintain sufficient system strength and dynamic reserves to support high flows on the Northern Minnesota 500 kV lines and Manitoba high-voltage direct-current (HVDC) lines. Insufficient system strength and reactive support will limit Manitoba exports to the U.S. Existing transmission expansion plans, as modeled in this analysis, address these issues and are sufficient for the anticipated levels of Manitoba exports.

The Manitoba HVDC ties and the 500 kV transmission system in Northern Minnesota require reactive support from synchronous generators, the Dorsey and Riel synchronous condensers, and the Forbes SVC to maintain the expected level of Manitoba exports. Without sufficient reactive reserves, the system could be unstable for nearby transmission disturbances. The current transmission plans, as modeled in this analysis, address this issue.

9.8 Weak System Issues

Composite Short-Circuit Ratio (CSCR) is an indicator of the ability of an ac transmission system to support stable operation of inverter-based generation. A system with a higher CSCR is considered strong and a system with a lower CSCR is considered to be weak. CSCR is calculated as the ratio of the composite short-circuit MVA at the points of interconnection (POI) of all wind/solar plants in a given area to the combined MW rating of all those wind and solar generation resources.

Low CSCR operating conditions can lead to control instabilities in inverter-based equipment (Wind, Solar PV, HVDC and SVC). Instabilities of this nature will generally manifest as growing voltage/current oscillations at the most affected wind or solar plants. In the worst conditions (i.e., very low CSCR), oscillations could become more wide-spread and eventually lead to loss of generation and/or damage to renewable generation equipment if not adequately protected against such events.

This is a relatively new area off concern within the industry. The issue has emerged as the penetration of wind generation has grown. Understanding of the fundamental stability issues is rapidly growing as more wind plants are being installed in regions with weak ac systems. Equipment vendors, transmission planners and consultants are all working to gain a better understanding of the issues. Modeling and simulation tools have already been developed to enable detailed analysis of the phenomena. Wind and solar inverter control systems are being modified to improve weak system performance.

Synchronous machines (either generators or synchronous condensers) contribute short-circuit strength to the transmission system and therefore increase CSCR. Therefore, system operating conditions with more synchronous generators online will have higher CSCR. Also, stronger transmission ties (additional transmission lines or transformers, or lower impedance transformers) between synchronous generation and regions of wind and solar generation will increase CSCR. SVCs and STATCOMs do not contribute short-circuit current, and because they are electronic converter based devices with internal control systems similar to wind/solar inverters, their presence in a weak system region could further reduce the effective CSCR and exacerbate the control system stability issues that occur in weak system conditions.

There are two general situations where weak system issues generally need to be assessed:

- Local pockets of a few wind and solar plants in regions with limited transmission and no nearby synchronous generation (e.g. plants in North Dakota fed from Pillsbury 230 kV near Fargo).
- Larger areas such as Southwest Minnesota (Buffalo Ridge area) with a very high concentration of wind and solar plants and no nearby synchronous generation

This study examined the sensitivity of weak system issues in Southwest Minnesota. Observations are as follows:

The trouble spots identified in this analysis are not very sensitive to existing synchronous generation commitment. While there is very little synchronous generation within the area, the region is supported by a strong networked 345 kV transmission grid. Primary short circuit strength is from a wide range of base-load units in neighboring areas, and interconnected via the 345 kV transmission network. Commitment, decommittment or outages of individual synchronous generators do not have significant impact on CSCR in these identified areas.

Transmission outages will lower system strength and make the issue worse. When performing CSCR and weak system assessments as wind and solar penetration increases, it will be prudent to consider normal and design-criteria outages at a minimum (i.e, outage conditions consistent with MISO reliability assessment practices).

9.9 Mitigations

There are two approaches to improving wind/solar inverter control stability in weak system conditions:

- To improve the inverter controls, either by carefully tuning the equipment control functions or modifying the control functions to be more compatible with weak system conditions. With this approach, wind/solar plants can tolerate lower CSCR conditions.
- To strengthen the ac system, resulting in increased short-circuit MVA at the locations of the wind/solar plants. This approach increases CSCR.

The approaches are complementary, so the ultimate solution for a particular region would likely be a combination of both.

Mitigation through Wind/PV Inverter Controls

Standard inverter controls and setting procedures may not be sufficient for weak system applications. Loop gains of internal control functions inherently increase when system impedance increases, thereby reducing the stability margin of the controllers. Developers and equipment vendors must be made aware when new plants are being proposed for weak system regions so they can design/tune controls to address the issue. Wind plant vendors have made significant progress in designing wind and solar plant control systems that are compatible with weak system applications.

This approach becomes somewhat more difficult when there are wind/solar plants from multiple vendors in one region. The level of analysis requires detailed modeling of all affected wind plants at a level of detail that requires the use of proprietary control design information from the vendors. Vendors are very reluctant to share such data, except with independent consultants who can guarantee strict data security. However, this approach is gaining traction and a few projects have made effective implementations. The key to success is that project developers and equipment vendors must be informed beforehand that a given wind or solar plant will be installed at a weak system location. This enables the appropriate control design studies to be initiated before the project is installed.

In the event that such control-based approaches are not sufficient, it would be possible to further improve weak system performance by employing one or more of the system-level mitigations discussed below.

Mitigation by Strengthening the AC System

CSCR analysis of the Southwest Minnesota region shows that synchronous condensers located near the wind and solar plants would be a very effective mitigation for weak system issues. Synchronous condensers are synchronous machines that have the same voltage control and dynamic reactive power capabilities as synchronous generators. Synchronous condensers are not connected to prime movers (e.g. steam turbines or combustion turbines), so they do not generate power.

Other approaches that reduce ac system impedance could also offer some benefit:

- Additional transmission lines between the wind/solar plants and synchronous generation plants
- Lower impedance transformers, including wind/solar plant interconnection transformers

Series capacitors on transmission lines could be used to increase CSCR and to improve the transmission system's capability to transfer energy out of regions with high concentrations of wind and solar resources. However, series capacitors create subsynchronous frequency resonances in the transmission system which affect the performance of control systems within wind and solar plants. These resonances introduce an additional challenge to wind/solar plant control designs, which must maintain stable operation in the presence of the resonant conditions.Mitigation through "must-run" operating rules for existing generation was found to be not very effective. The plants with synchronous generators are not located close enough to effected wind/solar plants.

10 REFERENCES

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9. Hawaiian Electric Company, Hawaii Natural Energy Institute, "Oahu Wind Integration Study." www.hnei.hawaii.edu

11 APPENDICES

Appendix A1 – AC Input Files

Appendix A2 – Powerflow Case Flow Info

Appendix A3 – Bus Angle Diagrams

Appendix A4 – Contingency Analysis Spreadsheets

Appendix A5 – Maps

Appendix A6 – Transmission Costs

Appendix A7 – HVDC

Note: The Appendices are available upon request from Great River Energy.

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce Report

Docket No. E999/CI-13-486

Dated this **5th** day of **November 2014**

/s/Sharon Ferguson

Attachment 2

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Attachment 3

Energy Efficiency in Minnesota: Information for the U.S. EPA on Draft Rule 111(d) of the Clean Power Plan

Prepared By: Minnesota Department of Commerce Staff

Minnesota has a long history and ongoing commitment to statewide energy efficiency (EE) policies. It is important to note the expansiveness of Minnesota's overarching statewide energy policies when considering development of the State Implementation Plan (SIP) and future compliance with the Clean Power Plan.

While many codified policies have been in place for decades, Minnesota's landmark Next Generation Energy Act (NGEA) was passed in 2007 creating or amending existing statewide policy goals to meet the changing needs of the state. While there was an emphasis on energy conservation and renewable energy within the NGEA, other areas around greenhouse gas emissions, state government energy conservation, reliability administration, and others were addressed. Details of the Next Generation Energy Act can be found in Minnesota Law Chapter 136 (Senate File 145). Since passage of the NGEA, additional laws have been passed establishing new programs and refining existing policies. Below is a comprehensive table of statutory references for energy efficiency programs and policies in the State of Minnesota:

Codified Energy Efficiency Policies and Goals	Statute/Law/Executive Order
Energy Planning and Policy Goals	MN Statute 216C.05
Energy Efficiency and Conservation	MN Statute 216B.16
Recovery of Electric Utility Infrastructure Costs	MN Statute 216B.1636
Energy Conservation Policy Goal	MN Statute 216B.2401
Energy Conservation Improvement	MN Statute 216B.241
Decoupling of Energy Sales From Revenues	MN Statute 216B.2412
State Government Energy Savings Plan	MN Statute 216C.03
Energy Audit Programs	MN Statute 216C.31
Guaranteed Energy Savings Program (GESP)	MN Statute 16C.144
Local Energy Efficiency Program (LEEP)	MN Statute 216C.42 and 216C.43
Rev It Up Program	MN Statute 216C.145 and 216C.146
Trillion Btu Revolving Loan Fund	MN Statute 16B.322
Property Assessed Clean Energy (PACE)	MN Statute 216C.436

Utility Energy Efficiency Programs (Minnesota Conservation Improvement Program)

Goals:
The Next Generation Energy Act of 2007 established an Energy Efficiency Resource Standard (EERS) for electric and natural gas utilities in Minnesota, including investor-owned utilities, electric cooperatives, and municipal utilities (see Minn. Stat. §216B.241 subd 1c.) Under the EERS, utilities are required to develop plans to achieve energy savings equal to 1.5% of gross annual retail sales through conservation improvement programs designed to help their customers improve end-use energy efficiency. The Conservation Improvement Program (CIP) is a statewide program administered by electricity and natural gas utilities that helps Minnesota households and businesses use electricity and natural gas more efficiently. CIP programs promote energy efficient technologies and practices to residential, commercial, and public customers through various means including

marketing, incentives, and technical assistance. Commerce reviews and approves utility CIP filings to ensure that energy savings are calculated accurately, statutory requirements are met, and programs meet cost-effectiveness standards.

In addition to customer demand-side management, electric utilities are allowed to count savings from electric utility infrastructure (EUI) improvements[1] approved by the Minnesota Public Utilities Commission (MPUC) under Minn. Stat. §216B.1636.[2] Such savings count toward the 1.5% savings goal on top of a minimum savings goal of 1.0% from end-use efficiency measures, as long as the infrastructure improvements result in increased energy efficiency greater than that which would have occurred through normal maintenance activity.

Utilities may request a lower goal than the 1.5% standard based on a conservation potential study, historical conservation experience and other factors. However, for investor-owned utilities, the Commissioner of Commerce may not approve a savings goal less than 1.0%.

Investment and Cost Recovery:

Under Minnesota Statutes §216B.241 subd. 1c, all Minnesota electric utilities are subject to an annual energy savings goal of 1.5% of annual retail energy sales, excluding sales to customers that have opted out of utility-administered EE programs. State law requires Minnesota electric and natural gas utilities to invest at least 1.5% and 0.5% annually of their gross operating revenues (GOR), respectively, in conservation improvement programs, except that Xcel Energy's electric utility, as an owner of a nuclear generating plant in Minnesota is required to invest at least 2.0% of GOR annually in CIP. Minnesota statutes include mechanisms for IOUs to recover the costs of implementing CIP programs and earn a performance incentive based on the level of savings and amount of net benefits achieved.[3] Most IOUs file their status reports as part of larger consolidated filings that include proposed adjustments to CIP cost-recovery riders based on the previous year's expenditures and performance incentive earned. Concurrent with the status report review process, Commerce staff review the proposed cost-recovery adjustments and file recommendations concerning the proposed adjustments to the Commission. After considering Commerce's recommendations and any public comments filed, the Commission then approves the proposed adjustments as is or with modifications. For cooperative and municipal utilities, local utility commissions, boards or city councils determine their own cost recovery mechanisms.

Cost-Effectiveness:

Like many states with ratepayer-funded EE programs, Minnesota requires that the programs meet certain cost-effectiveness standards. Minnesota's standards are based on the standard benefit-cost tests defined in the California Standard Practice Manual[4] for demand-side programs. At a minimum, utility residential and commercial/industrial portfolio segments must pass the Societal and Utility Cost tests, which compare the cost of EE investments to their benefits to society and the utility, respectively. In addition, no Minnesota utility can be required to make an EE investment that is not cost-effective (M.S. §216B.241 subd. 1c (f)). These cost-effectiveness standards ensure that ratepayer funds are used wisely.

Planning and Reporting:

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[1] For example, installing higher than standard-efficiency transformers, low impedance distribution lines, or reconfiguring transmission system to reduce total losses.

[2] Minn. Stat. §216B.1636 does not apply to municipal or cooperative utilities. However, the Department of Commerce has allowed municipal and cooperative utilities to count qualifying electric utility infrastructure (EUI) project savings towards their CIP goals even though they are not subject to Minn. Stat. §216B.1636.

[3] See Minn. Stat. §216B.16, subd. 6b and 6c.

[4] *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.*

Attachment 3

Unlike many states, all electric utilities in Minnesota are required to run EE programs and are subject to a single annual energy savings goal, including municipal utilities and electric cooperatives (together, "customer-owned" utilities.) Investor-owned utilities file three-year EE plans while customer-owned utilities file one-year plans. All utilities are required to file annual status reports summarizing their actual EE expenditures and achievements annually. The Minnesota Department of Commerce is charged with reviewing and approving utility plans and savings reports. The Minnesota Public Utilities Commission has authority to approve cost recovery of EE expenditures and EE performance incentives for rate-regulated utilities, though Commerce serves as an intervener in such dockets. Local commissions handle cost recovery issues for customer-owned utilities.

Investor-owned utilities (IOU) file triennial CIP plans on June 1; the next triennial plans, for 2017-2019, will be filed on June 1, 2016. Plans filed June 1 are generally approved as is or with modifications by October or November of the same year. Customer-owned utilities (COU) file annual CIP plans on June 1; the next annual plan, for 2016, will be filed on June 1, 2015. COU plans filed by June 1 are generally approved by Commerce on December 1 of the same year.Electric IOUs file annual status reports on April 1 of each year. COUs file their annual status reports on June 1 of each year. After reviewing each status report and any public comments received, Commerce issues a decision to accept the status report or accept with modifications. Minnesota is unique in the large number of utilities implementing DSM programs in the state. About 180 investor- and customer-owned utilities are subject to DSM implementation and reporting requirements. Also, unlike many states, customer-owned utilities are subject to the same energy savings goal, 1.5% of annual retail energy sales, as investor-owned utilities. Minnesota statutes also allow utilities to aggregate their programs under joint action agencies and generation and transmission cooperatives. Under this option, the aggregating agency can elect to be responsible for achieving the 1.5% energy savings goal, rather than each member organization.

To address the challenges of data management across such a large number of actors with multiple layers of program administrative and reporting responsibilities, the State has developed an innovative software platform called ESP® through a public-private partnership with Energy Platforms, LLC. ESP® provides version management, a complete data trail for all transactions, and a publically accessible database of EE data with built-in analytic functions. ESP® is an essential tool for ensuring that utility EE programs are cost-effective, achieving their approved energy savings goals, and meeting the requirements of State law. ESP® is made up of two applications, ESP (operations) and ReportingESP. ESP (operations) is a user-configurable application for program implementation and energy savings tracking. All data within ESP (operations) are private by default, but can be shared with other organizations. All Minnesota utilities have access to the State's Digital TRM, described above, through ESP (operations). Utilities can also "consume" the Digital TRM Smart Measures from their own tracking systems. Program implementation data within ESP (operations) are at the measure-level. Each measure, as applied, retains application data, savings outputs, and other information attached by the user (such as invoices, work papers, rebate application forms, etc.)

ReportingESP is the State's designated tool for EE reporting by Minnesota utilities and also serves as a central, publically-accessible database of EE data and utility sales and customer class data. EE data is entered at the program-level in ReportingESP and can be dynamically grouped and analyzed by utility, aggregator, program category, market segment, etc. The State is currently funding the development of web services to allow the automatic transfer of program implementation data from ESP (operation) and other tracking systems. When this effort is completed, EE data flow will be fully automated from start to finish, from project submittal through reporting.

<u>Evaluation, Measurement and Verification for Utility Energy Efficiency:</u>

As described above, Minnesota utilities report gross energy efficiency achievements annually to Commerce. For prescriptive programs, utilities are expected to use energy savings algorithms derived from Minnesota's statewide Technical Reference Manual (TRM) or utility-specific algorithms approved as part of their efficiency plans. Custom projects generally do not use pre-approved savings algorithms. Commerce staff evaluate a selection of custom projects each year to ensure that appropriate baselines are used, that calculated savings are reasonable, and that sound engineering methodologies are employed.

Large custom projects with estimated annual savings of at least 1 million kWh or 20,000 dekatherms of natural gas require measurement and verification (M&V) plans to be submitted to Commerce for review. The plans must conform to specific M&V protocols developed by Minnesota stakeholders that are based on the International Performance Measurement and Verification Protocol (IPMVP).[5] Final savings for these projects are ultimately based on the measured savings.

Minnesota's TRM was developed by an independent third-party contractor with input from Commerce and Minnesota utilities. Commerce manages the TRM and has developed a schedule for regular updates to ensure that the TRM reflects current building codes and equipment standards, markets, and technologies. The schedule includes a third-party evaluation and update every three years, coinciding with the filing of the IOU triennial plans, and annual updates to add or drop measures. An advisory committee and technical working groups have been formed and meet regularly to advise Commerce on TRM content, policies, and procedures.

Minnesota's TRM has also been implemented as a cloud-based library of measure calculators on ESP®, a software platform for energy efficiency tracking and reporting developed in part through funding from Commerce. The measure calculator library or "Digital TRM" is accessible to all Minnesota utilities, implementation contractors, and trade allies and is key to the State's effort to collect accurate energy savings data. Use of the Digital TRM provides Minnesota utilities and their partners a common set of rigorously tested calculators for energy savings measures, thereby ensuring that savings are calculated consistently and accurately across the state. The individual measure calculators or "Smart Measures" also package and retain application data, savings outputs, and other project information, providing a complete data trail for each measure as applied in the field. More information on ESP® and the Digital TRM is provided below.

Line Losses from Utility Energy Efficiency Programs:

EPA specifically requests states to explain whether they account for line losses in their EE savings. Minnesota does account for line losses. Savings are first calculated and verified at the meter, then scaled up to the generator using approved line loss factors. Generally speaking, each utility derives its line loss factor(s) by comparing total energy generated and/or purchased to total energy sales. The difference in these two figures represents the line losses, which is then divided by total energy generated and/or purchased to yield a line loss factor. Some utilities use more sophisticated approaches to derive separate residential and commercial line loss factors, and a peak kW line loss factor that represent losses at peak utility system demand.

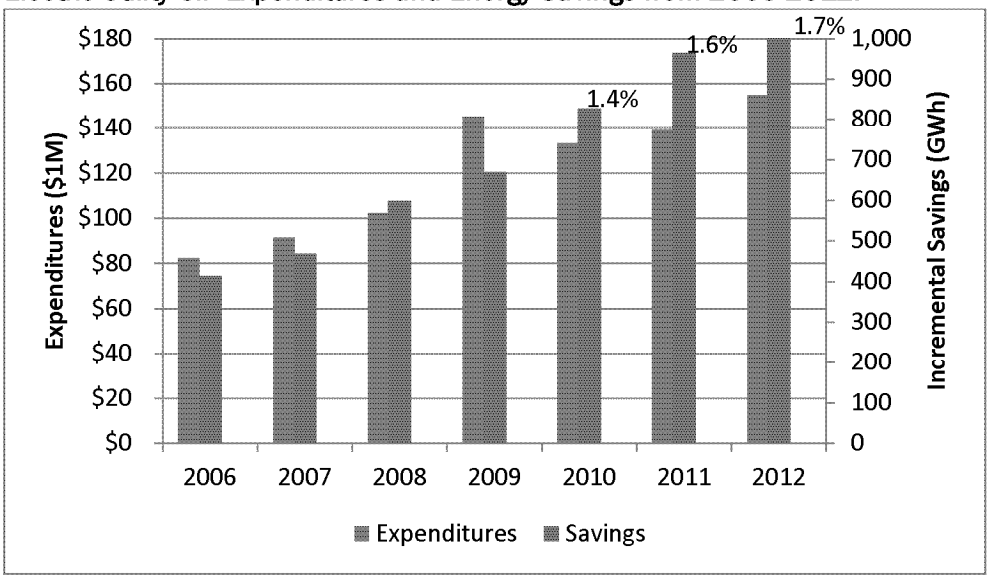
Historical Utility Efficiency Performance:

Overall electric and natural gas CIP expenditures and savings have grown significantly since 2006, the earliest year for which Commerce began tracking and reporting individual utility CIP performance. Total electric and natural gas savings over 2011 and 2012 totaled 2,001 gigawatt-hours (GWh) and 5.6 billion cubic feet (bcf), respectively. Combined, these energy savings are equivalent to approximately 12,400,000 million-BTUs (MMBTU), On average, each megawatt-hour (MWh) of electricity saved in Minnesota avoids 1,823 pounds (0.9 tons) of CO_2 emitted to the atmosphere,

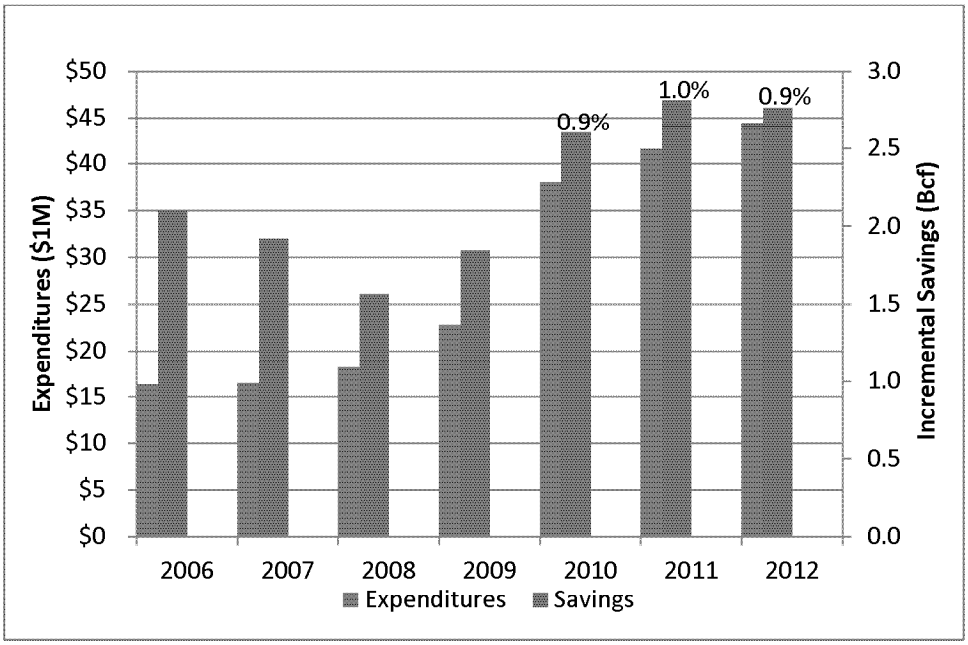
[5] Docket No. E,G999/CIP-06-1591

while each dekatherm (Dth) of natural gas saved avoids 121 pounds (0.1 tons) of CO_2.[6] The following graphs summarize statewide, aggregator, and utility-level data from 2006 and 2012 and reflect data in Reporting$_{ESP}$ as of April 24, 2014.

Electric Utility CIP Expenditures and Energy Savings from 2006-2012.



Gas Utility CIP Expenditures and Energy Savings from 2006-2012.



[6] The electric CO_2 emissions rate is provided by the Minnesota Pollution Control Agency to the Minnesota Public Utilities Commission and Minnesota Department of Commerce in Docket No. E,G999/CI-00-1343 and was last updated on March 17, 2009. The gas CO_2 emissions rate of 121 pounds of CO_2 per Dth is a standard emissions factor for natural gas combustion and assumes a properly tuned boiler or furnace such that nearly 100% of fuel carbon is converted to CO_2.

Non-Utility Energy Efficiency and Emerging Programs

While the Conservation Improvement Program may be the largest efficiency program in the state, it is not encompassing of all activity in the state relating to achievement of the State's energy policy goals. There are many energy conservation and efficiency activities that do not include direct utility involvement. Additional energy efficiency programs administered by a state agency in Minnesota include:

Program	Administering Agency	Description
Weatherization Assistance Program (WAP)	Minnesota Department of Commerce	To help low-income families make their homes more energy efficient
Guaranteed Energy Savings Program (GESP)	Minnesota Department of Commerce	Executive Order 11-12 mandates that "In state-owned buildings, state agencies shall adopt cost-effective energy efficiency and renewable energy strategies through the following actions to achieve no less than an aggregate 20 percent reduction in energy use." To attain the savings, the Commissioner of Commerce was to create and staff an Office of Guaranteed Energy Savings Programs to offer a technical assistance program for state agencies, local units of government, and school districts that elect to implement energy-saving and renewable energy improvements through Guaranteed Energy Savings Contracts.
Local Energy Efficiency Program (LEEP)	Minnesota Department of Commerce	*Under Development* State-led process and access to funding to allow non-performance contract energy efficiency projects in local governments, school districts, and other municipal entities.
Rev It Up Program	Minnesota Department of Commerce	*Under development* A statewide revolving loan program will allow for up to $100 million in revenue bonds to be issued and outstanding at any given time, to provide low-cost, loan-term loans to local units of government, industrial, commercial

		businesses, or healthcare facilities seeking to finance energy efficiency and/or renewable energy projects.
Trillion Btu	Minnesota Department of Commerce; St. Paul Port Authority	A statewide program, administered by the St. Paul Port Authority (SPPA), assists Minnesota businesses finance energy retrofit or renewable energy projects to reduce energy consumption, with a goal to reduce up to one trillion BTU(s) annually. The program leverages $15 million in ARRA funds granted to the SPPA by Commerce.
Fix Up Loan Program	Minnesota Housing Finance Authority; Minnesota Department of Commerce	
Southwest Regional Development Commission PACE Program	Minnesota Department of Commerce; Southwest Regional Development Commission	The Southwest Regional Development Commission administers an 18 county regional PACE program. This program enables business owners to place a special assessment against their property to finance and install energy retrofits, and use the accrued operational energy saving to repay the special assessment over a term up to 20 years. This program leverages $650,000 in ARRA funds granted to the SWRDC by Commerce.
Green Loan for Business Program	Minnesota Department of Commerce; Community Reinvestment Fund	A revolving loan program, administered by the Community Reinvestment Fund (CRF) within the Xcel Energy territory, that provides low-cost loans to businesses seeking financing to install energy retrofits. The program leverages $500,000 in ARRA funds granted to CRF by Commerce.
Energy Efficiency for Existing 501 (c)(3) Loan Program	Minnesota Department of Commerce; Center for Energy and Environment	A statewide revolving loan program, administered by the Center for Energy and Environment, that provides low-cost loans to non-profit entities seeking financing to install energy retrofits. The program leverages approximately $225,000 in ARRA funds granted to CEE by Commerce.

Attachment 3

MHFA Fix Up Loan Program	Minnesota Department of Commerce; Minnesota Housing Finance Agency	A statewide residential energy efficiency loan program, administered by MHFA, provides low-cost, unsecured loans to homeowners seeking financing to install energy retrofits in their homes. The MHFA is committed to lending $10 million in loans by leveraging a $1 million loan loss reserve fund supported by ARRA funds granted to MHFA by Commerce.
Residential Energy Efficiency Loan Program	Minnesota Department of Commerce; Center for Energy and Environment	Established in 1993, this statewide residential energy efficiency revolving loan program, administered by the Center for Energy and Environment, provides home owners with low-cost financing to install energy efficient retrofits in their homes. The program has leveraged $1.6 million in Exxon Oil Overcharge funds originally appropriated to Minnesota.
Energy Savings Partnership Program	Minnesota Department of Commerce; St. Paul Port Authority	A statewide revolving loan program, administered by the St. Paul Port Authority, provides low-cost loans to local units of government that pursue energy savings performance contracts (ESPC) under any of the applicable statutes (16C.144, 471.345, or 123B.65). The program leverages a $2 million loan loss reserve fund supported by ARRA funds.
PACE Program	Minnesota Department of Commerce; St. Paul Port Authority	Property Assessed Clean Energy (PACE) enables business owners to place a special assessment against their property to finance and install energy retrofits (EE & RE) and use the accrued operational energy savings/production to repay the special assessment over a term up to 20 years. Currently, the St. Paul Port Authority administers a statewide "PACE of

		Minnesota." Businesses access the program through local governmental units that have authorized a Joint Powers Agreement with the SPPA to administer the program within their local jurisdiction
Sustainable Buildings 2030 (SB2030)	Minnesota Department of Commerce; University of Minnesota Center for Sustainable Building Research	The Minnesota Sustainable Building 2030 (SB 2030) required that on July 1, 2010 all Minnesota State bonded projects — new and substantially renovated – would be required to meet the Minnesota Sustainable Building 2030 (SB 2030) energy standards. The SB2030 - 2010 Energy Standards have been established for over 44 building types. These Energy Standards are based on a 60% energy use reduction from a baseline building of the same type and location with energy performance typical of the existing buildings of that type in 2003 (including buildings built long before 2003).
Buildings, Benchmarking and Beyond (B3)	Minnesota Department of Commerce	Required energy benchmarking tool for reporting the energy usage in all state buildings for use in measuring progress toward a goal of reducing energy consumption by 20 percent[7]
GreenStep Cities	Minnesota Pollution Control Agency	Minnesota GreenStep Cities is a voluntary challenge, assistance and recognition program that established 28 best practices for use by cities to prioritize and achieve their sustainability and quality-of-life goals.
Energy Codes	Minnesota Department of Labor and Industry	Responsible for the adoption and enforcement of statewide building energy codes. Minnesota is currently in the process of adopting the standards set in the 2012

[7] See Minn. Stat. §§ 16B.325, subd. 1; 216B.241, subd. 9.; 2001 Minn. Laws, Ch. 212, Art. 1, Sec. 3

		International Energy Conservation Code (IECC).[8]

Evaluation, Measurement and Verification of Non-Utility Energy Efficiency:
State-run energy efficiency programs also use M&V protocols to validate energy savings. The Guaranteed Energy Savings Program (GESP) requires energy service companies (ESCOs) to measure and verify savings annually using best practices outlined by the International Performance Measurement and Verification Protocol (IPMVP) and the Federal Energy Management Program (FEMP). Local units of government entering into a GESP contract are required by the joint powers agreement to provide the annual M&V reports provided by the ESCO as well as enter facility utility information into the statewide B3 benchmarking system.

Programs under development such as the Local Energy Efficiency Program (LEEP) and Rev It Up Community Loan Program will use varying degrees of formal M&V. LEEP is planned to follow IPMVP and FEMP guidelines for post-implementation verification of savings, but since LEEP is not designed as a performance contract, the baseline measurements may not be as robust as a full investment grade audit may otherwise provide. However, any projects will require LGUs to submit annual M&V reports similar to GESP.

LGUs may also enter into performance contracts with ESCOs directly outside the GESP program. They are required to submit the performance contract agreement, which includes calculated annual energy savings, to the Department of Commerce by a variety of state statutes. Commerce may request annual M&V reports from the LGU to track aggregate energy savings through efficiency measures.

As stated in the previous EM&V section, some of these programs will have M&V protocols as built in requirements. It is the goal of the MN Department of Commerce to aggregate these savings through the B3 tool and M&V reporting, and the use of designated software or reporting requirements by the EPA should be avoided.

[8] http://www.dli.mn.gov/ccld/codes.asp

From:	Monique Faye
To:	Monique Faye
Sent:	11/21/2014 4:23:37 PM
Subject:	NACAA Washington Update
Attachments:	112114wklyupdateshell.pdf

The Friday, November 21, 2014 Washington Update is attached.

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WASHINGTON UPDATE

National Association of Clean Air Agencies
NACAA

This Week in Review – November 17-21, 2014

(1) EPA Issues Two "Ministerial" Actions to Implement Court-Approved Motion to Lift Stay on CSAPR (November 21, 2014) – EPA signed two "ministerial" actions (ones in which the agency implements the wishes of the court and exercises no discretion of its own) related to implementation dates for the Cross-State Air Pollution Rule (CSAPR). These actions are consistent with EPA's June 26, 2014 motion to the U.S Court of Appeals for the District of Columbia Circuit to lift the stay on CSAPR that was entered by the court on December 30, 2011, and "toll" (i.e., move or delay) the deadlines by three years; other than dates, the actions change no other aspects of CSAPR. The D.C. Circuit granted EPA's motion to lift the stay on October 23, 2014. In the first action, an Interim Final Rule with a request for public comment, EPA aligns the dates in CSAPR with the revised CSPAR implementation schedule as approved by the D.C. Circuit when it lifted the stay. This action addresses implementation of Phase 1 – to occur in 2015 – and Phase 2 – to occur in 2017. In the second action, a Notice of Data Availability, EPA aligns the final default allocation years with the revised court-ordered implementation schedule. This NODA is required by the original CSAPR but was not previously issued by EPA because the rule was stayed; with the stay now lifted, EPA is proceeding with the NODA. The allocations identified in the spreadsheet that accompanies the NODA remain unchanged from those published by EPA on its website in June 2012. For further information: http://epa.gov/crossstaterule/ and http://epa.gov/crossstaterule/actions.html

(2) EPA Announces It Will Not Finalize Volume Standards for 2014 RFS by End of This Year, Petroleum Group Threatens to Sue (November 21, 2014) – EPA announced it will not finalize its proposed 2014 volume standards under the Renewable Fuels Standard (RFS) program before the end of this calendar year. Published by EPA on November 29, 2013 (78 *Federal Register* 71732), the proposal marked the first time the agency sought to exercise its statutory authority to reduce mandated RFS volumes, which the agency proposed to do for the advanced biofuel and total renewable fuel standards based on its updated production projections. The proposed rule drew many comments for and against it and has continued to generate considerable controversy. EPA indicates that it intends to take action on the 2014 standards rule in 2015 before, or in conjunction with, action on the 2015 standards rule. In November 2013, when EPA proposed the 2014 standards, the agency said that pursuing reductions from the statutory

levels was "intended to put the program on a manageable trajectory while still allowing for growth in advanced and total renewable fuels over time." The agency also said that although renewable fuel production was increasing, overall U.S. gasoline consumption was less than Congress projected when it established the RFS in 2007, thereby resulting in the "E10 blend wall" – the point at which the fuel pool is saturated with ethanol and the only way to continue using ethanol would be to require increased used of ethanol blends beyond E10 (which is gasoline blended with 10 percent ethanol), like E15 and E85. In a related matter, the American Fuel & Petrochemical Manufacturers (AFPM) provided notice to EPA of its intent to sue the agency for failure to timely determine renewable fuel volumes and promulgate RFS regulations for 2014. Noting that under the Clean Air Act EPA was to promulgate the 2014 standards by November 30, 2013, and referring to delays in promulgation of previous years' standards, AFPM stated, "EPA's track record concerning the issuance of RFS rules has become an egregious pattern of non-compliance…. For 2014, EPA's delay reached new levels and the Agency has not yet issued a final rule, even though the compliance year is almost concluded. These repeated inexplicable delays are a violation of the Clean Air Act." For further information: http://epa.gov/otaq/fuels/renewablefuels/regulations.htm and http://www.4cleanair.org/sites/default/files/Documents/rfs_2014_notice_of_intent_to_sue_112014.pdf

(3) House Passes "Promoting New Manufacturing Act" Air Permitting Bill (November 20, 2014) – The U.S. House of Representatives voted 238-172 to approve H.R. 4795, the "Promoting New Manufacturing Act," a bill aimed at speeding the issuance of air permits by requiring EPA to issue any implementation guidance or regulations for a new or revised National Ambient Air Quality Standard (NAAQS) concurrently with the standard. Until such guidance or regulations are published, the new or revised NAAQS would not apply to the review and disposition of preconstruction permit applications. The bill would also require EPA to annually list on its website its estimate of the total number of preconstruction permits issued each year by any permitting authority, as well as the percentage of permits issued within one year after the date of filing a complete application and the average length of time for EPA's Environmental Appeals Board to issue a final decision on petitions to grant or deny a preconstruction permit application. In addition, it would require EPA to provide a report to Congress annually on actions being taken to expedite the processing of preconstruction permits. The bill was sponsored by Rep. Steve Scalise (R-LA). The House rejected, by a 183-225 vote, an amendment sponsored by Rep. Henry Waxman (D-CA) to state that outdated air quality standards would not apply to the review and disposition of a preconstruction permit if the applicable federal, state, or local permitting agency determined that applying it would likely increase air pollution, slow permitting, or increase regulatory uncertainty. It passed by voice vote an amendment by Rep. Ed Whitfield (R-KY) to clarify that the bill does not prohibit states from imposing new or revised federal air quality standards under state or local law. Earlier this week, the White House issued a veto threat for the bill, asserting that it "would impose arbitrary and unnecessary requirements that could weaken the public health and environmental protections of the Clean Air Act" and would "increase uncertainty for

businesses and States." The Senate is not expected to pass the bill in the current legislative session. For further information: http://thomas.loc.gov/cgi-bin/query/z?c113:H.R.+4795 and http://www.whitehouse.gov/sites/default/files/omb/legislative/sap/113/saphr4795r20141117.pdf

(4) House Passes Secret Science Reform Act (November 19, 2014) – The House of Representatives approved a bill – by a vote of 237 to 190 – to prohibit EPA from proposing, finalizing or disseminating rules or assessments based on "science that is not transparent or reproducible." H.R. 4012, the Secret Science Reform Act of 2014, would amend the Environmental Research, Development, and Demonstration Act of 1978 to require that all scientific and technical information on which EPA relies to support covered actions must be specifically identified and publicly available in a manner sufficient for independent analysis and substantial reproduction of research results. "Covered actions" include a risk, exposure, or hazard assessment, criteria document, standard, limitation, regulation, regulatory impact analysis, or guidance. After the House vote, Rep, David Schweikert (R-AZ), who sponsored the bill, said, "For far too long, the EPA has approved regulations that have placed a crippling financial burden on economic growth in this country without public evidence to justify their actions, all the while keeping science in the shadows. This common-sense legislation forces the EPA to be accountable with their findings and brings transparency to the forefront of the regulatory process. The Secret Science Reform Act brings science out of the shadows." In a December 17, 2014 Statement of Administration Policy, the White House says the bill "would impose arbitrary, unnecessary, and expensive requirements that would seriously impede the Environmental Protection Agency's (EPA's) ability to use science to protect public health and the environment, as required under an array of environmental laws, while increasing uncertainty for businesses and States" and that if the President were presented with the bill his senior advisors would recommend that he veto it. For further information: https://www.congress.gov/bill/113th-congress/house-bill/4012?q=%7B%22search%22%3A%5B%22HR+4012%22%5D%7D and http://www.whitehouse.gov/sites/default/files/omb/legislative/sap/113/saphr4012r20141117.pdf

(5) House Approves Bill Instructing EPA on How to Select Science Advisory Board Members (November 18, 2014) – By a vote of 229 to 191, the House of Representatives passed H.R. 1422, the EPA Science Advisory Board Reform Act. With a stated purpose of amending the Environmental Research, Development, and Demonstration Act of 1978 to provide for Scientific Advisory Board (SAB) member qualifications and public participation, H.R. 1422 would set forth criteria to be followed by the EPA Administrator when selecting SAB members, stipulating who can and cannot serve. Included in the bill is a provision that "persons with substantial and relevant expertise are not excluded from the Board due to affiliation with or representation of entities that may have a potential interest in the Board's advisory activities, so long as that interest is fully disclosed to the Administrator and the public" as well as new requirements regarding soliciting and

responding to public comments. The day before the House vote, the White House issued a Statement of Administration Policy opposing H.R. 1422, which it says "would negatively affect the appointment of experts and would weaken the scientific independence and integrity of the SAB," and indicating that if the President were presented with the bill his senior advisors would recommend that he veto it. For further information: https://www.congress.gov/bill/113th-congress/house-bill/1422/text?q=%7B%22search%22%3A%5B%22HR+1422%22%5D%7D and http://www.whitehouse.gov/sites/default/files/omb/legislative/sap/113/saphr1422r20141117.pdf

(6) Keystone Pipeline Bill Fails to Pass Senate (November 18, 2014) – S. 2280, a bill to approve the Keystone XL pipeline, failed to gain sufficient votes to pass the Senate. With a vote count of 59 to 41, S, 2280 fell one vote short of the 60-vote threshold required for passage. On Friday, a companion bill, H.R. 5682, passed the House (see related article in the November 10-14, 2014 *Washington Update*). Like H.R. 5682, S. 2280 was intended to authorize construction of the Keystone XL pipeline by declaring approved the May 4, 2012 application by TransCanada to construct, operate and maintain the cross-border facilities for the pipeline, which would carry oil from Alberta to U.S. refineries on the Gulf Coast, and by deeming that the State Department's January 2014 Final Supplemental Environmental Impact Statement for the pipeline fully satisfies the National Environmental Policy Act and any law that requires federal agency consultation or review. Although he did not expressly state it, President Obama signaled in recent days that he would likely veto the bill if it were to reach his desk. For further information: https://www.congress.gov/bill/113th-congress/senate-bill/2280?q=%7B%22search%22%3A%5B%22s+2280%22%5D%7D

(7) Vitter, Inhofe Tell Administration It Should Conduct Cost-Benefit Allowance Before Proposing Ozone NAAQS Decision (November 20, 2014) – Senator David Vitter (R-LA), Ranking Member of the Senate Committee on Environment and Public Works, and Senator James Inhofe (R-OK) sent a letter to Howard Shelanski, Administrator of the Office of Management and Budget's (OMB's) Office of Information and Regulatory Affairs, asking that OMB ensure that EPA not propose a revised National Ambient Air Quality Standard (NAAQS) for ozone until the agency receives and considers a comprehensive cost-benefit analysis of the rule from the Clean Air Scientific Advisory Committee (CASAC). Vitter and Inhofe state in their letter that, "By any measure, the proposed rule will represent one of the costliest rules ever issued by EPA and will serve as one of the most devastating regulations in a series of over-reaching regulatory actions taken by this Administration that will limit investment and the ability of the U.S. economy to produce higher paying jobs for hard-working Americans." The Senators say that in various communications they have reminded EPA and CASAC of "CASAC's nondiscretionary duty under Section 109 of the Clean Air Act (CAA) to advise the Administrator 'of any adverse public health, welfare, social, economic, or energy effects which may result from various strategies for attainment and maintenance of' a new standard," but that no action was taken.

They further state that "[n]ow, just days from the scheduled proposal date [December 1, 2014] for the revised ozone standard, we have yet to see any evidence that EPA or CASAC intends to follow the law." Therefore, the Senators ask Shelanski to make sure EPA and CASAC follow the law, including by assessing "the public health and welfare losses that result from reduced income and employment due to the imposition of a costlier standard." They also assert that CASAC's advice to EPA on background levels is critical: "Although EPA has modeling tools that produce estimates of *average* background levels spread out over large geographic areas, it is difficult to say with precision what is actually 'background' at a specific air quality monitor during an ozone exceedance. Yet EPA proposes holding state and local officials accountable to reach ozone levels that may in fact be below background ozone levels and thus beyond their control." Vitter and Inhofe conclude by saying EPA should not move forward with setting a revised ozone standard until it has received CASAC's input on these issues. For further information: http://www.epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=ff7e9bac-3282-4a2d-b910-8a46540e2e66

(8) Senators Weigh in With EPA on Compliance Deadlines for Forthcoming Final Wood Heater NSPS (November 19, 2014) – Thirty-seven members of the U.S. Senate sent a letter to EPA Administrator Gina McCarthy asking that she ensure that the forthcoming final rule for warm air furnaces (residential wood heaters) provide at least one year before the new standards take effect. On February 3, 2014, EPA proposed New Source Performance Standards for residential wood heaters that would apply federal emission limits to a greater array of new residential wood combustion devices beyond the narrowly defined set of indoor wood stoves covered by the existing federal rules. As its preferred approach, EPA proposed two phases of emissions standards, with Phase I to take effect within 60 days of publication of the final rule and Phase II to take effect five years later. The agency also included an alternative approach with three phases of emissions standards, including the same Phase I standards as the preferred approach, an interim (Phase II) compliance standard that would take effect three years after promulgation of the final rule and the final (Phase III) emissions standards (the same as those in the final phase of the preferred approach) taking effect eight years after promulgation. In their letter to the Administrator, the Senators say EPA's proposed 60-day compliance deadline for Phase I "threatens unreasonable economic damage to furnace manufacturers in the United States." They also say the 60-day compliance period "stands in contrast to EPA's first NSPS for woodstoves, promulgated in 1988, which allowed small manufacturers a year to attain compliance and staggered effective dates for all other manufacturers." For further information: http://www.sessions.senate.gov/public/_cache/files/6108cd05-6733-416f-8d95-ac564a98a798/final-signed-copy-epa-waf-letter.pdf

(9) Senators Whitehouse and Schatz Introduce Legislation Calling for Carbon Fees (November 19, 2014) – Senators Sheldon Whitehouse (D-RI) and Brian Schatz (D-HI) introduced the "American Opportunity Carbon Fee Act" that

calls for sources to pay a fee for each ton of their carbon emissions. The fees would begin at $42 per ton in 2015 and increase each year by 2 percent (adjusted for inflation). The fee would be based on the Administration's "social cost of carbon" concept, which relates to the value of the harm caused by pollution. The fee would apply to all coal, oil and natural gas produced in or imported into the United States and would be aimed at large emitters of non-carbon greenhouse gases and carbon dioxide from non-fossil-fuel sources. The fees would be assessed and collected by the U.S. Department of the Treasury, based on data from EPA and the Energy Information Administration. According to the co-sponsors, the legislation would generate up to $2 trillion over 10 years, which would be returned to the public through a variety of possible programs, including tax cuts, assistance to low-income households, tuition assistance, infrastructure, climate mitigation and adaptation and other uses. For further information: http://www.whitehouse.senate.gov/news/release/sens-whitehouse-and-schatz-introduce-carbon-fee-legislation

(10) White House Task Force Urges That Federal Programs Be More Climate Resilient (November 17, 2014) – A White House task force comprised of 26 governors, mayors, county executives and tribal leaders has issued new recommendations to support local climate preparedness and resilience-building efforts. The recommendations include high-level guidance in five "overarching principle" areas and more specific recommendations in seven areas. Among the general principles, the task force proposes that the Federal Government "[r]equire consideration of climate-related risks and vulnerabilities in the design, revision, and implementation of all Federal policies, practices, investments, regulations, and other programs." The seven areas recommended for specific action include building resilient communities, improving resilience in the nation's infrastructure and ensuring resilience of natural resources, among others. The task force, formally called the *State, Local, and Tribal Leaders Task Force on Climate Preparedness and Resilience*, was established by a November 2013 Executive Order. Its goal is to help local leaders share experiences and provide the federal government with advice on how to address the impacts of climate change. For further information: http://www.whitehouse.gov/sites/default/files/docs/task_force_report_0.pdf

(11) White House Releases Community Climate Resilience Toolkit (November 17, 2014) – The White House has released a new website to help local communities plan for the impacts of climate change. The website, called the Climate Resilience Toolkit, provides information related to managing climate-related risks and improving community resilience to extreme events. The toolkit includes planning guidance, exemplary case studies, climate data tools, climate mapping tools, region-specific narratives on climate change and links to other resources, like free training courses and federal climate information centers. Although the toolkit's initial focus is on coastal flood risk and food resilience, it will be updated to address other areas, such as water, ecosystems, transportation and health. The National Oceanic and Atmospheric Administration developed the toolkit through a partnership of federal agencies in response to requests from the

State, Local, and Tribal Leaders Task Force on Climate Preparedness and Resilience. For further information: http://toolkit.climate.gov/

(12) Study Examines Impacts of State Clean Power Plan Implementation Choices (November 18, 2014) – A new analysis from the Center for Strategic International Studies and the Rhodium Group examines how state implementation choices under EPA's proposed Clean Power Plan (CPP) might affect energy markets. Some of the areas examined include likely plant retirements and the amount of new capacity expected to be built, as well as changes to the overall energy mix, consumer energy bills and coal and natural gas prices. The analysis found that two of the most significant implementation decisions states can make are whether to adopt a multi-state approach and whether to rely aggressively on energy efficiency measures. It found that multistate implementation plans could significantly lower new consumer energy costs related to CPP compliance. Aggressive reliance on energy efficiency measures, because they reduce the need to replace coal-fired power plants with low or zero carbon energy sources to meet CPP emissions targets, could preserve a larger future role for coal. The groups' results also indicate that replacing existing coal-fired power plants with natural gas combined cycle plants is the most cost-effective CPP compliance strategy. Further, the analysis predicts that the CPP's impacts will vary significantly across regions and that those impacts will in turn be influenced by the implementation choices made in other states. The full report is entitled *Remaking American Power: Potential Energy Market Impacts of EPA's Proposed GHG Emission Performance Standards for Existing Power Plants*. For further information: http://csis.org/files/publication/141107_Ladislaw_RemakingAmerPower_Web.pdf

(13) EPA Releases Guidance and Accounting Framework for CO_2 Emissions Associated With Biomass (November 19, 2014) – EPA has released new guidance and a revised accounting framework for CO_2 emissions associated with bioenergy and other biogenic sources. The new guidance, reflected in a memorandum signed by Acting Assistant Administrator Janet McCabe, discusses how biogenic CO_2 impacts could be considered within the context of EPA's proposed Clean Power Plan (CPP) and the Prevention of Significant Deterioration (PSD) Program. Regarding the CPP, the memorandum notes that EPA "expects to recognize the biogenic CO_2 emissions and climate policy benefits of waste-derived and certain forest-derived industrial byproduct feedstocks" in state CPP compliance plans. The PSD portion of the memorandum announces that EPA will later propose revised PSD regulations exempting greenhouse gas emissions from waste-derived feedstocks and non-waste biogenic feedstocks derived from sustainable forests or agriculture practices from Best Available Control Technology requirements. The accounting framework, described in a technical report entitled, *Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources*, revises a September 2011 draft to incorporate recommendations from an EPA Science Advisory Board, among others. For further information: http://www.epa.gov/climandechange/ghgemissions/biogenic-emissions.html

(14) Methane Emissions from Oil and Gas Industry Could Be Cut in Half in a Few Years, Environmental Groups Report (November 20, 2014) – In a new report, the Clean Air Task Force, Natural Resources Defense Council and Sierra Club detail a set of control measures that they claim would reduce methane emissions from the oil and gas industry by half in just a few years if implemented across the industry. Reducing methane from the oil and gas sector – the second-largest industrial contributor to GHG emissions – is critical to curbing climate change, the groups assert. The report, *Waste Not: Common Sense Ways to Reduce Methane Pollution from the Oil and Natural Gas Industry*, contains detailed information and data describing the industry and its sources of methane emissions. For each source category, the groups present their best estimate of current methane emissions, and then detail how EPA could require the implementation of "proven, in-use technologies and practices" to reduce those emissions. Their recommended measures include requiring leak detection and repair programs for all equipment at wellpads, gas processing plants, compressor stations and large aboveground distribution facilities; setting additional standards for new and existing compressors and gas-driven pneumatic equipment; and requiring well operators to capture methane and sell or use it on-site instead of releasing or flaring it. The report presents estimates of the total abatement that can be achieved from each emission source by utilizing these technologies and practices, as well as the abatement cost in each category. These estimates show that reducing methane from the oil and gas sector is among the most affordable greenhouse gas reduction opportunities, the groups assert. For further information:
http://www.catf.us/resources/publications/files/WasteNot_Summary.pdf

(15) NASUCA Issues Report Analyzing Impacts of Section 111(d) Proposal on Consumers (November 14, 2014) – The National Association of State Utility Consumer Advocates (NASUCA) has issued a report analyzing the impacts on consumers of EPA's proposed Clean Power Plan rule under Section 111(d) of the Clean Air Act. NASUCA is an association of the officials designated by states to represent the interests of utility consumers before regulators and the courts. The report, entitled *Implications of EPA's Proposed "Clean Power Plan,"* acknowledges the implementation costs associated with compliance, but recognizes that it will also provide significant consumer benefits, such as reduced health impacts and welfare risks resulting from climate change and decreases in energy costs. The report notes that consumer advocates must be involved in plan development and advocate least-cost planning from states as they develop their approaches. The report identifies a list of issues that consumer advocates should consider as the rule is implemented, such as intrastate and multi-state coordination, least-cost planning, the wholesale price of energy, mass-versus rate-based compliance, out-of-rule emissions, coal retirement, federal enforceability, nuclear challenges and opportunities and efficiency measurement. The report also identifies some of the pros and cons of different compliance approaches that states may be considering. For further information: http://nasuca.org/nwp/wp-content/uploads/2013/11/NASUCA-111d-final-report-20141114-2.pdf

(16) NRDC Analysis Shows Clean Power Plan Could Save Up to $9 Billion (November 19, 2014) – According to new modeling results from the Natural Resources Defense Council (NRDC), EPA overestimated the electric power industry's 2020 compliance costs with the proposed Clean Power Plan (CPP) by as much as $9 billion. NRDC argues that EPA's CPP analysis was too conservative and overestimated the costs associated with utilizing energy efficiency measures and renewable energy generation. The modeling results find that the proposed CPP could lead to total net health and environmental benefits of $59 billion in 2020 and $99 billion in 2030 after accounting for compliance costs. EPA's own analysis of the rule found lower 2020 and 2030 net benefits of $50 billion and $84 billion respectively. For further information: http://www.nrdc.org/air/pollution-standards/clean-power-plan-energy-savings.asp

(17) Significant GHG Cuts Needed to Hold Global Warming at Two Degrees Celsius, According to UN (November 19, 2014) – A new report by the United Nations Environment Program (UNEP) estimates that global greenhouse gas (GHG) emissions must shrink 15 percent by 2030 and 50 percent by 2050 to avoid a global temperature increase larger than 2 decrees Celsius, as measured from a 2010 baseline. According to UNEP, even steeper cuts are needed after 2050, requiring "net zero" GHG emissions in the 2080 to 2100 timeframe. The UNEP study, entitled *Emissions Gap Report 2014*, is released annually to analyze the gap between GHG emissions projections, which factor in future reduction commitments, and those required to hold global warming to 2 degrees Celsius or lower. Global average temperatures have risen 0.8 degrees Celsius since 1900. In addition to expressing future GHG emissions targets as percent reductions, the UNEP report also calculates a budget to quantify the amount of remaining allowable emissions. According to its analysis, global atmospheric emissions greater than 2,900 gigatons, measured from the 19th century onward, will lead to warming greater than 2 degrees Celsius. Approximately 1,900 gigatons of GHGs have already been emitted, approximately two-thirds of the total budget. In addition to estimating the global greenhouse gas emission levels consistent with a 2-degree temperature increase, the report also examines the potential for energy efficiency measures to help mitigate GHG emissions. For further information: http://4cleanair.org/sites/default/files/Documents/UNEP_Emissions_Gap_2014_Report.pdf

(18) EPA Proposes Revisions to GHG Reporting Rule for Petroleum and Natural Gas Industry (November 13, 2014) – EPA has proposed a rule that would amend the Greenhouse Gas (GHG) Reporting Program regulations for the Petroleum and Natural Gas Systems source category. The proposal would require several sources not previously covered by the rule to report their emissions of methane and other GHGs, including well oil completions and workovers with hydraulic fracturing, petroleum and natural gas gathering and boosting systems, and transmission pipeline blowdowns between compressor stations. It would also require the reporting of a well identification number for oil and gas wells covered in the Onshore Petroleum and Natural Gas Production segment. In addition, EPA proposed confidentiality determinations for new data elements contained in the

proposed amendments. EPA says that the proposed rule reflects the rapid growth and changes that have occurred in the oil and gas industry since the GHG Reporting Program requirements for this sector were originally promulgated in 2010. The proposed revisions are intended to improve data quality to enhance the ability of EPA and the public to analyze emissions, identify opportunities for improving the data and understand emissions trends. The proposal has not yet been published in the *Federal Register*. For further information: http://www.epa.gov/ghgreporting/documents/pdf/2014/documents/subpart_w_2015_revisions.pdf

(19) EPA Offers Technical Assistance For Evaluating Travel Efficiency Strategies (November 20, 2014) – EPA is, once again, offering technical assistance for up to three selected state, local or regional agencies interested in using the Travel Efficiency Assessment Method (TEAM) approach to assess the potential for greenhouse gas (GHG) and criteria pollutant emission reductions under alternative travel efficiency scenarios. The TEAM approach uses local travel activity information, sketch-planning travel activity analyses and MOVES emissions modeling to estimate potential emission reductions from combinations of travel efficiency strategies. This initiative follows case studies completed earlier this year by EPA in partnership with regional planners in Boston, Kansas City and Tucson. EPA invites letters of interest, by December 31, 2014, from local, regional, and state planning agencies for areas with a population above 200,000. For further information: http://www.epa.gov/otaq/stateresources/documents/2014-project-description-notice-2014-11-20.pdf and http://www.epa.gov/otaq/stateresources/ghgtravel.htm

(20) EPA Sued Over Missed Ozone Transport Deadlines (November 18, 2014) – The Sierra Club and Wild Earth Guardians have filed a lawsuit to force EPA to disapprove 21 state implementation plans (SIPs) for the 2008 ozone National Ambient Air Quality Standard (NAAQS). According to the plaintiffs, EPA should make a finding of "failure to submit" for the 21 SIPs because none addresses cross-state effects as required by the Clean Air Act's "good neighbor" provision. Beginning in 2011, the plaintiffs sought similar relief in the D.C. District Court for the District of Columbia, but that claim was denied earlier this year. EPA had opposed the environmental groups on the basis of a 2012 D.C. Circuit Decision, *EME Homer City Generation v. EPA*, 696 F.3d 7 (D.C. Cir. 2012), where the court interpreted the "good neighbor" provision and other parts of the Clean Air Act to strike down EPA's Cross-State Air Pollution Rule (CSAPR). The Supreme Court later reversed the D.C. Circuit on appeal and upheld CSAPR. The new Sierra Club and Wild Earth Guardians lawsuit cites the Supreme Court's *EME Homer* decision to require that states submit "good neighbor" SIP provisions within three years promulgation of a NAAQS. The 2008 Ozone NAAQS was finalized on March 12, 2008. The 21 states identified in the suit are Arkansas, California, Connecticut, Georgia, Illinois, Iowa, Kansas, Maine, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Mexico, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Virginia, Washington and West Virginia. The lawsuit was filed in the U.S. District Court for the Northern District of California.

(*Sierra Club v. McCarthy*, N.D. Cal, No. 3:14-cv-5091). For further information: http://www.4cleanair.org/sites/default/files/Documents/Litigation-Enviros_v_EPA-no_transport_in_2008_O3_plans-111814.pdf

(21) Environmental and Public Health Groups Sue EPA for Failure to Act on Lead SIPs (November 20, 2014) – The Center for Biological Diversity and Center for Environmental Health filed suit against EPA Administrator Gina McCarthy in the U.S. District Court for the Northern District of California alleging that EPA failed to undertake mandatory duties to implement the 2008 National Ambient Air Quality Standard (NAAQS) for lead. They claim that EPA failed to make findings of failure to submit nonattainment state implementation plans (SIPs) for Iowa (Pottawattamie area) and Puerto Rico (Arecibo area); failed to take final action on nonattainment SIP submittals by Florida (Tampa area), Minnesota (Eagan area), Ohio (Cleveland and Delta areas), and Texas (Frisco area); and failed to take final action on the infrastructure SIP submittal by North Carolina. The plaintiffs seek court-ordered deadlines for EPA to complete these actions. For further information:
http://www.biologicaldiversity.org/campaigns/get_the_lead_out/pdfs/2014-11-20_2008_Lead_NA_SIP_Complaint.pdf

(22) EPA Rejects Group's Effort to Overturn Title V Permit Based on Alleged Endangered Species Act Violation (November 21, 2014) – EPA denied a petition by the Wild Equity Institute requesting that the agency object to a Title V permit issued by the Bay Area Air Quality Management District to Pacific Gas & Electric for the Gateway gas-fired power plant in Contra Costa County, California. The group contended in its petition that the permit "failed to ensure that Gateway satisfies all applicable pollution control requirements" because it failed to address EPA's alleged obligation under the Endangered Species Act (ESA) to obtain incidental take authorization for three endangered species endemic to the nearby Antioch Dunes National Wildlife Refuge, including the extremely rare Lange's Metalmark Butterfly. EPA denied the petition on the grounds that the requirements of the ESA are not "applicable requirements" for purposes of the Clean Air Act Title V program. "While the EPA may have specific obligations under the ESA in certain circumstances, the ESA itself is not a part of the CAA, not a part of a SIP or federal implementation plan that implements the CAA, and not otherwise an applicable requirement as that term is defined" by the Title V regulations," EPA stated in the petition order. Nor is compliance with ESA required under the Prevention of Significant Deterioration provisions or EPA's implementing regulations, the agency concluded. The order denying the petition was signed by EPA Administrator Gina McCarthy on October 15; notice of the decision was published in the *Federal Register* on November 21. For further information: http://www.gpo.gov/fdsys/pkg/FR-2014-11-21/pdf/2014-27641.pdf and http://www.epa.gov/region7/air/title5/petitiondb/petitions/gateway_decision2013.pdf

(23) EPA Publishes Final MATS Rule on Startup and Shutdown Provisions in *Federal Register* (November 19, 2014) – EPA has published in the *Federal*

Register a rule that finalizes the agency's reconsideration of the Mercury and Air Toxics Standards (MATS) and the Utility New Source Performance Standards (NSPS) provisions applicable during periods of startup and shutdown. The rule includes updated work practice standards that must be employed during startup and shutdown periods and adjusts certain monitoring and testing requirements that apply during these periods. The final rule was announced on November 7, 2014 and reported in the *Washington Update* of November 10-14, 2014. For further information: http://www.gpo.gov/fdsys/pkg/FR-2014-11-19/pdf/2014-27125.pdf and http://www.epa.gov/mats/actions.html

(24) EPA Proposes Amendments to MATS Reporting Provisions (November 19, 2014) – EPA has published in the *Federal Register* a Direct Final Rule and an associated Proposed Rule addressing the reporting provisions for the Mercury and Air Toxics Standards (MATS). The Direct Final Rule amends MATS reporting requirements by temporarily calling for affected sources to submit all of their mandated emissions and compliance reports to EPA via the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool and suspending temporarily the requirement that sources submit certain reports through the Electronic Reporting Tool and the Compliance and Emissions Data Reporting Interface (CEDRI). The rule takes effect on January 5, 2014, unless EPA receives adverse comments by December 19, 2014. If the agency receives adverse comments, the affected provisions will be withdrawn and the proposed rule will be used to continue the rulemaking process. For further information: http://www.gpo.gov/fdsys/pkg/FR-2014-11-19/pdf/2014-27126.pdf (Direct Final Rule) and http://www.gpo.gov/fdsys/pkg/FR-2014-11-19/pdf/2014-27127.pdf (Proposed Rule)

(25) FERC Endorses Additional Time for Source's MATS Compliance Beyond Fourth Year (November 20, 2014) – The Federal Energy Regulatory Commission (FERC) has, for the first time, validated a request for a source to have extra time to comply with the Mercury and Air Toxics Standards (MATS) beyond the fourth year state and local agencies are able to provide under the regulation. The request was made by the Kansas City, Kansas Board of Public Utilities for an additional six months beyond the April 16, 2016 compliance deadline (until October 15, 2016). FERC has reviewed whether taking the plant offline in April 2016 would violate reliability standards and reserve margins and found that it would cause a problem. Pursuant to FERC policy, the commission reviewed the request for additional time and has provided the information to EPA. According to FERC officials, they know of only two other such requests that may be forthcoming. For further information: http://www.4cleanair.org/sites/default/files/Documents/Wyandotte_County_Request.pdf

(26) EPA Publishes Amendments to Portland Cement NESHAP and NSPS in *Federal Register* (November 19, 2014) – EPA has published in the *Federal Register* amendments to the Portland Cement National Emission Standards for

Hazardous Air Pollutants (NESHAP) and New Source Performance Standards (NSPS) that make technical corrections to the final standards issued in February 2013, as well as remove the affirmative defense provisions in the rule to comport with a court ruling. The proposal was announced on November 4, 2014 and summarized in the *Washington Update* of November 3-7, 2014. The technical corrections included clarifications in definitions and other amendments. The comment deadline for the proposal is January 20, 2015. For further information: http://www.gpo.gov/fdsys/pkg/FR-2014-11-19/pdf/2014-26905.pdf and http://www.epa.gov/airquality/cement/actions.html

(27) EPA Proposes Brick and Clay MACT (November 21, 2014) – EPA has proposed an air toxics standard for the brick and structural clay products and clay ceramics industries source category. The agency originally issued Maximum Achievable Control Technology (MACT) standards for this source category in 2003, but they were subsequently vacated in the court. This proposal replaces the vacated MACT. According to EPA, the new proposal provides small sources with "flexible compliance options." EPA is not proposing work practice standards for mercury for the source category, but is seeking comment and data from the public on that issue. Brick and clay facilities are major sources of hydrogen fluoride, hydrogen chloride and other hazardous air pollutants (HAPs). EPA estimates that the rule will reduce emissions of HAPs by 440 tons per year. The agency has identified 44 major sources, 36 of which are small businesses. For further information: http://www.epa.gov/ttn/brick/brickpg.html

(28) EPA Announces Final Results of Chemical Speciation Network Assessment (November 17, 2014) – EPA's Air Quality Assessment Division has completed its year-long assessment of the $PM_{2.5}$ Chemical Speciation Network (CSN) and finalized a list of 42 monitoring sites recommended for defunding. The CSN Assessment Team, which included members from EPA's Office of Air Quality Planning and Standards, EPA regional offices and NACAA, was tasked with optimizing the network by making it financially sustainable, redistributing resources to new or high-priority sites from those of lower priority or benefit, extracting more value from the existing network, and fully leveraging the value of other existing monitoring networks. Its goal was to reduce total network costs by 20%, from $6.7 million to $4.7 million annually. The team undertook a quantitative evaluation of the 189-site network based on each site's contribution to the support of objectives, including state implementation plan development, health studies, trends analysis, urban versus rural increments, and regional haze. Updates and draft defunding lists were shared with NACAA and other state and local stakeholders during the assessment process. Under the team's final recommendations, 42 sites will no longer be funded for laboratory analysis through the CSN national contract, and the CSN will continue with 147 sites beginning in 2015. In addition, the CSN $PM_{2.5}$ mass measurement will be eliminated at nearly all sites, and there will be minor changes to sampling frequency, carbon blank frequency and shipping procedures. EPA's regional office Air Division Directors were notified of the results of the assessment on November 10, and the results were shared more widely this week. For further information:

http://www.4cleanair.org/sites/default/files/Documents/FinalResultsPM25ChemicalSpeciationNetworkAssessment-111014.pdf

The Week Ahead

- Congress in Recess – November 24 – December 1, 2014
- Thanksgiving Day – November 27, 2014

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From:	Stewart, Lori
To:	briefings
CC:	Burley, Veronica; Hambrick, Amy; McCabe, Janet; Dunham, Sarah
Sent:	8/15/2014 1:02:42 PM
Subject:	Monday Biomass meeting materials
Attachments:	Administrator Biomass Update 081814FINAL.docx; Biomass in Power Sector.docx; Expected Stakeholder Reaction.docx

The briefing materials for the 3:30 biomass meeting with the Administrator are attached. Thanks very much.

From: Missimer, Katie on behalf of Noe, Paul
CC: Tim_hunt@afandpa.org; Noe, Paul
Sent: 7/23/2013 6:14:08 PM
Subject: Docket ID No. EPA-HQ-OAR-2012-0640, Kraft Pulp Mills NSPS Review
Attachments: AFPA Kraft NSPS comments 7.23.13 Full.pdf; image001.jpg

Please find attached AF&PA's comments on EPA's proposed Kraft Pulp Mills NSPS Review that were submitted through the electronic docket at Regulations.gov.

AF&PA supports EPA's conclusion that technology has not changed to warrant major changes in the NSPS emission limits for PM and TRS. In addition, EPA was correct and within its legal authority to focus its review on recovery furnaces, lime kilns and smelt dissolving tanks and their emission of PM and TRS. However, we are very concerned with changes to the startup, shutdown, and malfunction (SSM) provisions and EPA's assertion that the standards apply at all times, when it has been demonstrated that operational and process variability necessitates venting under certain circumstances for worker and equipment safety reasons. EPA should either defer any changes to the SSM provisions or adopt the approach in the September 2012 Subpart S Residual Risk and Technology Review final rule so the requirements for the applicable equipment are the same in MACT and NSPS (we have attached our comments from that rulemaking so they are part of the Kraft Pulp NSPS record). Finally, EPA needs to adjust the opacity allowances from 2 to 4% and the calculation basis from quarterly to semi-annual to account for the variability found in the performance database of recovery furnaces (The attached NCASI comments go into more detail on these technical and monitoring issues). The semi-annual requirement also will be in line with the reporting requirements under Subpart BB and BBa.

If you have any questions regarding our comments please feel free to contact our Senior Director of Air Quality Programs, Tim Hunt, at 202-463-2588 or tim_hunt@afandpa.org.

Regards,

Paul Noe
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********** ATTACHMENT NOT DELIVERED **********

This Email message contained an attachment named
image001.jpg
which may be a computer program. This attached computer program could contain a computer virus which could cause harm to EPA's computers, network, and data. The attachment has been deleted.

This was done to limit the distribution of computer viruses introduced into the EPA network. EPA is deleting all computer program attachments sent from the Internet into the agency via Email.

If the message sender is known and the attachment was legitimate, you should contact the sender and request that they rename the file name extension and resend the Email with the renamed attachment. After receiving the revised Email, containing the renamed attachment, you can rename the file extension to its correct name.

For further information, please contact the EPA Call Center at (866) 411-4EPA (4372). The TDD number is (866) 489-4900.

********** ATTACHMENT NOT DELIVERED **********

American Forest & Paper Association

July 23, 2013

EPA Docket Center (EPA/DC)
Environmental Protection Agency
Mailcode 2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460

RE: Docket ID No. EPA–HQ–OAR–2012-0640, Kraft Pulp Mills NSPS Review (78 *Federal Register* 31316, May 23, 2013)

The American Forest & Paper Association ("AF&PA") appreciates the opportunity to submit comments on the proposed revisions to the Kraft Pulp Mills NSPS (78 Fed. Reg. 31316, May 23, 2013). AF&PA serves to advance a sustainable U.S. pulp, paper, packaging, and wood products manufacturing industry through fact-based public policy and marketplace advocacy. AF&PA member companies make products essential for everyday life from renewable and recyclable resources and are committed to continuous improvement through the industry's sustainability initiative - *Better Practices, Better Planet 2020*. The forest products industry accounts for approximately 4.5 percent of the total U.S. manufacturing GDP, manufactures approximately $200 billion in products annually, and employs nearly 900,000 men and women. The industry meets a payroll of approximately $50 billion annually and is among the top 10 manufacturing sector employers in 47 states.

AF&PA's sustainability initiative - *Better Practices, Better Planet 2020* - is the latest example of our members' proactive commitment to the long-term success of our industry, our communities and our environment. We have long been responsible stewards of our planet's resources. Our member companies have collectively made significant progress in each of the following goals, which comprise one of the most extensive quantifiable sets of sustainability goals for a U.S. manufacturing industry: increasing paper recovery for recycling; improving energy efficiency; reducing greenhouse gas emissions; promoting sustainable forestry practices; improving workplace safety; and reducing water use.

We supply family-wage jobs, lead the way on recycling and renewable energy, sustainably use renewable resources, and reduce greenhouse gases by using carbon-neutral energy and sequestering CO_2. Unfortunately, these important contributions are challenged by an unprecedented wave of new regulatory proposals under the Clean Air

Act including updates to the Kraft Pulp Mills NSPS that could cause severe unintended harms if not carefully designed. To address this challenge, we stand ready to work with EPA to achieve a regulatory path for a sustainable future.

Thank you for your consideration of the important issues included in these comments. Please feel free to contact Tim Hunt at 202-463-2588 on my staff if you have questions or need more information.

Sincerely,

Paul Noe
Vice President for Public Policy
American Forest & Paper Association

cc: J. McCabe
P. Tsirigotis
R. Dunkins
K. Spence
J. Bradfield

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Attachment A	NCASI Comments on Proposed New Source Performance Standards for Kraft Pulp Mills ((78 Fed. Reg. 31316, May 23, 2013), July 23, 2013.
Attachment B	AF&PA Comments on Proposed National Emission Standards for Hazardous Air Pollutants From the Pulp and Paper Industry (76 Fed. Reg. 81328, December 27, 2011), February 27, 2012.
Attachment C	AF&PA Supplemental Comments on Proposed National Emission Standards for Hazardous Air Pollutants From the Pulp and Paper Industry (76 Fed. Reg. 81328, December 27, 2011), June 27, 2012.

ED_000419-0004071

I. Introduction

The pulp and paper industry has reduced emissions significantly since the original implementation of the Kraft Pulp Mill NSPS, through application of MACT (and in some cases BACT) standards on the same source categories and equipment. While we agree with many of the proposed changes (e.g., harmonizing the standards for new and reconstructed units with the new source MACT standards), some of the proposed changes are unsupported and unworkable, specifically the addition of the language that states that the PM and TRS standards apply at all times. AF&PA and its members are committed to operating in an environmentally responsible and sustainable manner. However, the U.S. pulp and paper industry faces many regulatory obligations and fierce competition from overseas manufacturers. In the face of such existing economic pressure, this rule could make matters worse by prohibiting mill upgrades that would trigger a rule with which the industry cannot comply.

As described in detail in these comments, EPA has the legal discretion and technical justification to revise the proposed Subpart BBa standards while still providing ample protection to health and the environment and applying the same emissions controls as the MACT rules. EPA has ample discretion to make pragmatic choices that would appropriately balance EPA's responsibility to protect health and the environment with the Agency's (and the US Government's) need to protect and promote the productive capacity of the Nation.

II. Executive Summary

AF&PA supports EPA's conclusion that technology has not changed to warrant major changes in the emission limits for PM and TRS. In addition, EPA was correct and within its legal authority to focus its review on recovery furnaces, lime kilns and smelt dissolving tanks and their emission of PM and TRS. However, we are very concerned with changes to the startup, shutdown, and malfunction provisions and EPA's assertion that the standards apply at all times, when it has been demonstrated that operational and process variability necessitates venting under certain circumstances for worker and equipment safety reasons. EPA should either defer any changes to the SSM provisions or adopt the approach in the September 2012 Subpart S Residual Risk and Technology Review final rule so the requirements for the applicable equipment are the same in MACT and NSPS. Finally, EPA needs to adjust the opacity allowances from 2 to 4% and the calculation basis from quarterly to semi-annual to account for the variability found in the performance database of recovery furnaces. The semi-annual requirement also will be in line with the reporting requirements under Subpart BB and BBa.

III. Scope of EPA's Review

As EPA recognized in the preamble to the proposed rule, the Clean Air Act provision for periodic (8-year) review of NSPS only applies to NSPS that have been promulgated: TRS and PM emission limitations for kraft recovery furnaces, smelt dissolving tanks, lime kilns, digester systems, brown stock washer systems, evaporator systems, and brown stock washer systems. See 78 Fed. Reg. at 31,321 ("Today's proposed NSPS review focuses on the PM and TRS emission standards in Subpart BB that are due for review under CAA section 111(b)(1)(B).") The 8-year review provision in CAA section 111(b)(1)(B) by its terms addresses only review of existing standards, not imposing additional performance standards. See also *Portland Cement Ass'n v. EPA*, 665 F.3d 177, 193 (D.C. Cir. 2011) ("it is unclear whether EPA has such a duty with respect to pollutants it has not previously regulated"). There is no statement in the statute establishing any deadline for EPA to consider whether to adopt NSPS for new pollutants or new emission sources not covered by the current regulations.

In fact, EPA was not even required to complete a comprehensive review of the current Subpart BB regulations: CAA section 111(b)(1)(B) gives EPA the option of determining that periodic review "is not appropriate in light of readily available information on the efficacy" of the existing NSPS. See 78 Fed. Reg. at 31,322. AF&PA provided EPA with information that we believe demonstrated that EPA could and should have made such a finding, rather than going through a full review of the existing standards. See, e.g., AF&PA November 22, 2011 comments on EPA's October 24, 2011, proposed plan for periodic review of NSPS, 76 Fed. Reg. 65,655 (EPA Docket ID EPA-HQ-OAR-2010–0223-0008).

Nevertheless, EPA chose to conduct a review of the Kraft Pulp Mill NSPS. In so doing, EPA had broad discretion to determine the sources that it would evaluate and the pollutants for which it would consider establishing standards. EPA's decision not to expand the sources or the pollutants currently covered under Subpart BB was well within that discretion.

EPA is under no obligation to add pollutants, nor to consider adding pollutants, to those already regulated under Subpart BB. Nothing in CAA section 111 requires that NSPS cover all pollutants emitted by a source, and EPA has never interpreted it that way. See, e.g., *National Lime Ass'n v. EPA*, 627 F.2d 416, 426 (D.C. Cir. 1980) (observing that, while EPA had determined that lime plants were sources of nitrogen oxides, carbon monoxide, and sulfur dioxide as well as particulates, standards of performance were proposed and ultimately promulgated only for particulate matter.); 70 Fed. Reg. 9706, 9711 (Feb. 28, 2005) (declining to set NOx limits for boilers below 100

mmBTU/hr. heat input, based on current emission levels, available technologies, and costs); 74 Fed. Reg. 51,950, 51,957 (Oct. 8, 2009) ("The statutory scheme thus provides EPA with significant discretion to determine which pollutant(s) should be regulated under the NSPS."); 75 Fed. Reg. 54,970, 54,996 (September 9, 2010) (declining to set CO limits for cement kilns in part because new emission units "are designed to combust fuel as efficiently as possible, and CO emissions from fuel combustion are minimized, regardless of any potential emission limit"). In fact, before expanding the Kraft Pulp Mill NSPS to cover additional pollutants, EPA would have to justify its departure from its prior decisions about which pollutants the NSPS should cover.[1] Certainly EPA is under no obligation to include pollutants in NSPS before EPA, in its discretion, determines that it has enough information to decide whether federal standards of performance are necessary or appropriate for the pollutant. *Cf.* 78 Fed. Reg. at 31,321.

As a practical matter, there would be little benefit to expanding the number of pollutants subject to emission limitations in the Kraft Pulp Mill NSPS. First of all, there are relatively few new affected facilities being constructed, and so there would be relatively little to be gained by EPA spending the resources to develop NSPS for additional pollutants. EPA has recognized that this is an appropriate reason for choosing not to promulgate NSPS. See 76 Fed. Reg. 65,655, 65,658-59 (Oct. 24, 2011). There has not been a greenfield chemical pulp mill built in the United States in over 20 years. Because of a variety of factors, including stringent environmental controls and reduced access to forest fiber supplies due to land development and access to Federal forests, there almost certainly will be few if any new pulp mills built in the U.S. in the coming eight years. Moreover, because of overcapacity, environmental regulations, and the like, there likely will be only a few new Subpart BB affected facilities installed in the next eight years. In the decade from 1990-1999, 21 new kraft recovery furnaces and 25 new lime kilns came on-line in the United States. In 2000-2010, only 3 new kraft recovery furnaces and 3 new lime kilns came on-line (and one recovery furnace and one lime kiln were at a mill that has since shut down). New source review technology reviews should be more than adequate to assure that these few new units use the best emission control technology.

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[1] Clearly the fact that pulp mill sources emit volatile organic compounds, nitrogen oxides, carbon monoxide, and greenhouse gases, none of which are subject to emission limitations in the Kraft Pulp Mill NSPS, has been known for many years. See, e.g., RTI March 29, 2013 memorandum, "Technology Review and Regulatory Options for the Kraft Pulp Mill NSPS," Docket ID. No. EPA-HQ-OAR-2012-0640-0048, p. 10. If EPA were required to include in NSPS every pollutant that is emitted by a source category, that objection to the Kraft NSPS should have been raised years ago.

Secondly, other Clean Air Act regulations already comprehensively address emissions from kraft pulp mills, such that adding pollutants to the Kraft Pulp Mill NSPS would provide little if any incremental benefit. MACT standards in 40 C.F.R. Part 63 Subpart S require mills to control emissions of volatile hazardous air pollutants, through collecting and incinerating vent gases or using clean condensates to minimize release of volatile HAPs, which also controls VOC emissions (as do measures to minimize TRS emissions under the existing Subpart BB NSPS). EPA very recently completed a review and revision of those Subpart S standards. See 77 Fed. Reg. 55,698 (Sept. 11, 2012). EPA has acknowledged, in its proposed plan for reviewing and prioritizing NSPS, that MACT standards result in effective control of criteria pollutants as well. See 76 Fed. Reg. 65,655, 65,658-59 (Oct. 24, 2011); see also, e.g., 75 Fed. Reg. at 54,996 (declining to set NSPS for VOC emissions from cement kilns because VOCs would be adequately controlled by NESHAP limits on THC emissions).

In addition, all kraft pulp mills are large enough sources of conventional pollutants to be above the "major stationary source" threshold for major-source new source review requirements. The new source review regulations will require BACT or LAER for pollutants (other than HAPs) at new and modified sources that might be addressed in current or revised kraft pulp mill NSPS, and the statutory criteria for those technology requirements make them at least as stringent as, and generally more stringent than, NSPS.

Moreover, a number of recently promulgated or pending EPA regulations that are not specifically directed at pulp mills will impose additional limits on their emissions, because they will require further reductions from large sources of the types of pollutants emitted by pulp mills. These include, for example, more-stringent ambient air quality standards and EPA requirements for implementation of those standards, such as the NOx SIP call; visibility protection and regional haze programs; other regional pollutant transport programs; and Boiler MACT standards in 40 C.F.R. Part 63 Subpart DDDDD. These and other programs will require pulp mills to spend billions of dollars on additional emission controls (for existing as well as new sources) in the coming years.

A special case is presented by greenhouse gases (GHGs). EPA has ample practical reasons not to consider adding GHGs to the Kraft Pulp Mill NSPS. As demonstrated above, EPA is not required to promulgate NSPS for all, or indeed for any, pollutants emitted by a particular source category. Although EPA has made an "endangerment finding" with respect to GHG emissions from motor vehicles, 74 Fed. Reg. 66,496 (Dec. 15, 2009), that finding does not by its terms address GHG emissions from pulp mills. But even if it did, in contrast to section 202(a)(1), which requires EPA to set

standards for emissions of "any air pollutant" from new motor vehicles that, in the Administrator's judgment, cause or contribute to air pollution that "may reasonably be anticipated to endanger public health or welfare," section 111 contains no requirement that EPA include emission limitations in current NSPS for all air pollutants that are emitted by a given source category, even for pollutants that EPA has determined may reasonably be anticipated to endanger public health or welfare. Compare CAA sections 111(b)(1)(A), (f)(2)(B), (g)(2).

In any event, including GHGs in the Kraft Pulp Mill NSPS would be premature. First, no court has held that EPA is authorized to use NSPS under CAA section 111 to combat climate change. See, e.g., EPA's Combined Motion To Govern Further Proceedings and Response to Environmental and State Petitioners' Motion To Govern Further Proceedings in New York v. EPA, D.C. Cir. No. 06-1322, June 18, 2007, at 8 ("To date neither *Massachusetts* nor any other judicial decision has specifically addressed either the legal or policy aspects of the potential regulation of greenhouse gas emissions under section 111 of the Act…."). There are numerous reasons why CAA section 111 is not an appropriate vehicle for addressing climate change. Among other things, the fact that GHG emissions do not have local effects, but have been identified as a concern only as they build up in the global atmosphere, means that controlling their emissions from new and modified sources using the best demonstrated technology is likely not to be the most cost-efficient way of achieving desired reductions in global GHG emissions. Virtually everyone agrees that stabilizing GHG concentrations in the global atmosphere would be an enormously costly proposition, and therefore it is particularly important that any GHG reductions be obtained in a cost-effective manner. NSPS, which by statute must be based on an evaluation of the best-performing emission control technology for a particular emission unit, do not incorporate any explicit consideration of whether the same or greater reduction in GHGs could be achieved at lower cost through other measures. Also, NSPS typically are expressed as uniform emission rates for every unit in a particular source category or subcategory, without providing for consideration of site-specific factors or incorporating the flexibility necessary to minimize the cost of emission reductions on a global scale.

Inclusion of GHGs in the Kraft Pulp Mill NSPS would be premature on technical grounds, as well. Technologies for control of GHGs are just beginning to be developed, and it could actually be counterproductive for EPA to establish NSPS for GHGs, which likely would not be reviewed for at least another eight years, based on current technologies. Also, a large portion of GHG emissions from kraft pulp mills comes from biomass, and EPA is currently in the midst of developing its policy with respect to regulation of biogenic GHG emissions, in light of the carbon cycle. See 76

Fed. Reg. 43,490 (July 20, 2011). A recovery furnace, for example, can be viewed as an energy efficiency device—recovering energy value from a byproduct of the pulping process that would otherwise be wasted—and also a device whose carbon emissions displace carbon emissions from fossil fuel that otherwise would be transformed from subsurface deposit to atmospheric pollutant. EPA does not yet have the conceptual framework to address these distinct qualities of pulp mill GHG emission sources. Thus, there are numerous legal and practical reasons for EPA to exercise its ample discretion not to include GHGs in the Kraft Pulp Mill NSPS.

EPA also was justified in choosing not to expand the list of "affected facilities" covered by the Kraft Pulp Mill NSPS. First of all, as with adding pollutants to the list of those covered by Subpart BB, the Clean Air Act does not require EPA to review its previous decision not to include other emission units in the NSPS, nor does it require EPA to regulate, or even consider regulating, all emission units at a source category for which EPA chooses to promulgate NSPS. See CAA section 111(a)-(b). EPA in fact often has chosen to regulate only some emission units at industrial plants. See, e.g., 73 Fed. Reg. 35,838, 35,848, 35,868 (June 24, 2008) (adding fluid coking units, not previously regulated, to list of affected facilities in Petroleum Refineries NSPS).

But in any event, there is no reason for EPA to consider adding other affected facilities to the Kraft Pulp Mill NSPS. EPA regulated "all process gas streams which have been identified as major sources of TRS compounds or particulate matter at kraft pulp mills" in the original Subpart BB NSPS. 41 Fed. Reg. 42,012, 40,213 (September 24, 1976). That conclusion remains valid today. When EPA initially promulgated the Kraft Pulp Mill NSPS, it noted that boilers were a significant source of emissions at pulp mills, but it chose not to address those emissions because EPA anticipated promulgating NSPS for industrial boilers. See *id.* at 40,213. EPA has since promulgated, and reviewed and revised, NSPS for industrial boilers. 40 C.F.R. Part 60 Subparts Db and Dc. EPA also recently promulgated MACT standards for industrial boilers and process heaters. 40 C.F.R. Part 63 Subpart DDDDD. Those NSPS and NESHAPs control the biggest source of emissions at kraft pulp mills not covered by the Subpart BB NSPS.

Likewise, the NESHAPs applicable to kraft pulp mill processes, 40 C.F.R. Part 63 Subparts S and MM, thoroughly regulate the process sources of volatile hazardous air pollutants and HAP metals, and therefore the sources of TRS and particulate matter, at kraft pulp mills, applying technology requirements at least as stringent as could be imposed under NSPS. To the extent that the NESHAPs have identified additional emission points not addressed by the NSPS, the fact that those emission points at a new or modified sources will already be covered by new source or existing source MACT standards, respectively, based on emission rates of the best-performing

sources, means that no practical benefit would arise from adding those emission points to the Kraft Pulp Mill NSPS, as EPA has recognized. See 78 Fed. Reg. at 31,322.

Additionally, while not technically part of review of standards of performance for kraft pulp mills, EPA also was correct in determining not to expand NSPS to other chemical pulping processes. When it originally promulgated Subpart BB, EPA considered setting standards for sulfite and neutral sulfite semichemical pulping processes as well as for the kraft process. EPA determined at that time that there would be little benefit to establishing an NSPS for those types of mills, and the considerations that led EPA to that conclusion are even stronger today, as sulfite and NSSC pulping have become even less prevalent. See EPA, "Screening Study on Feasibility of Standards of Performance for Two Wood Pulping Processes," November 1978 (EPA Docket ID EPA-HQ-OAR-2012–0640-0029).

IV. Technology Review

A. We Support the Conclusion that There Are No New Control Technologies that Should Be Required

EPA has correctly concluded in the preamble that the technologies being used to control PM and TRS emissions from sources regulated under NSPS Subpart BB have not changed. PM emissions are controlled by ESPs and scrubbers, and TRS emissions are reduced using process controls, scrubbers, or incineration. There have been no changes in the technologies used in the industry since the last review of Subpart BB (or since implementation of the pulp and paper MACT standards) to control PM, TRS, or any other criteria pollutants.

In addition, nothing fundamental has changed as it relates to the technologies available to control TRS emissions at Kraft pulp mills or the ability of those technologies to mitigate or eliminate the unavoidable excess emissions during some operational periods. Absent such new or improved technologies, there is no basis for EPA to revise the standards to indicate that they apply at all times. Additional discussion related to excess emissions during startup, shutdown, and safety-related venting episodes is provided in Section VI below.

B. We Support the Conclusion that New/Reconstructed Source PM Limits Should be Revised to Match the New Source MACT Limits

New and reconstructed lime kilns and recovery furnaces are subject to PM emission limits and opacity monitoring under both the Kraft NSPS and the Chemical Recovery

Source MACT Standards in 40 CFR 63, Subpart MM. The new source PM and opacity limits in MACT Subpart MM are more stringent than those in NSPS Subpart BB. As these limits represent what new and reconstructed kilns and furnaces have achieved and the units would have to meet the new source MACT standards anyway, we agree that it is appropriate to revise the limits in Subpart BBa for new and reconstructed lime kilns and recovery furnaces to match the PM and opacity limits in MACT Subpart MM. There is no cost impact for this change.

We also agree that it is appropriate only to change the PM limit for new/reconstructed smelt tanks that are associated with new recovery furnaces. Facilities often replace or reconstruct existing smelt tanks without modifying the associated recovery furnace or modifying the existing smelt tank scrubber. Therefore, it is not cost effective to lower the PM limit for these units because a lower PM limit would likely require a scrubber replacement for a reconstructed smelt tank.

V. Monitoring and Testing Provisions

A. Comments on changes to monitoring and testing requirements

Initial and Repeat Performance Testing for Condensable Particulate Matter (CPM)

EPA is proposing under Subpart BBa to require initial and repeat CPM emissions testing in conjunction with filterable PM testing. EPA cites the lack of CPM data and the need to develop a better understanding of CPM emissions from pulp and paper sources as the reasons for this proposal.

Recent work carried out by NCASI has identified several unresolved issues with the new version of EPA Method 202, promulgated in December 2010. Details are provided as part of NCASI comments in Attachment A. The main conclusions are summarized here:

1. Method evaluation studies carried out by NCASI indicate that the new M202 yields train blank values around 5.5 mg. EPA's field evaluation study also yielded an average train blank of 5.33 mg, with values ranging from 4.6 to 6.2 mg. The currently promulgated version of M202 however only allows a maximum blank correction of 2 mg. The resulting positive bias associated with subtracting only 2 mg (as opposed to the observed ~6.0 mg) can be a significant component of the total CPM measured during tests on low-emitting sources.
2. NCASI studies on a low-emitting source (natural gas package boiler) using the new M202 also indicate the potential for positive bias due to the capture of SO_2

in the impingers and subsequent characterization of this SO_2 as SO_4 (and CPM) in the method.

3. NCASI recently carried out characterization studies on concurrently collected filterable particulate (EPA Method 5 – front half) and CPM (new EPA Method 202 – back half) samples from a DCE recovery furnace. The primary cation captured in the CPM train was ammonium (NH_4^+) while the anions included sulfate, chloride, and carbonate. By comparison, the front half sample did not contain any NH_4^+, suggesting that the ammonium captured in the back-half cannot be attributed to a partial breakthrough of filterable particulate. The presence of sodium in the front-half catch, and its absence in the back-half catch, further confirms that there was no breakthrough of filterable particulate (sodium sulfate particulate is captured on the front-half filter). These results indicate the potential for positive bias in CPM measurements in the presence of free ammonia. Any free ammonia in stack gases would pass through the front-half filter, react with any acid gases to form ammonium sulfate or ammonium chloride, and be characterized as CPM during subsequent gravimetric measurements. Ammonium was also identified as the predominant cation on CPM filters obtained from wood-fired boilers.

NCASI is carrying out additional CPM method evaluation studies as part of the ongoing technical studies program, including (a) identifying the source and extent of SO_2 and other method artifact biases and (b) comparing M202 against other equivalent test methods. EPA should therefore defer proposing the CPM testing requirement until more information on the unresolved method issues becomes available. Any CPM data generated in the interim would therefore be of questionable quality and would further contribute to the uncertainty surrounding CPM emissions.

Testing Frequency

EPA has proposed to require repeat testing at least once every 60 months for PM and TRS. We would request that, to provide maximum operational flexibility, the testing be required once every 5 calendar years, at any time during the fifth calendar year.

B. Comments on changes to monitoring allowances

Opacity and TRS Monitoring Allowances

EPA is proposing to (a) lower the opacity monitoring allowance for recovery furnaces from 6% to 2% and (b) add an opacity monitoring allowance of 1% for lime kilns. These monitoring allowances also include *startup* and *shutdown* periods. EPA is proposing that compliance with the monitoring allowances be calculated over a

quarterly reporting period[2] and requests comments on this requirement, specifically, on whether a semiannual calculation basis would be more appropriate.

EPA's conclusions on the ability of new/modified/reconstructed NSPS recovery furnaces and lime kilns to comply with these requirements is based on their review of COMS and TRS CEMS data in the 2011 Pulp and Paper ICR. NCASI has examined the conclusions from this analysis[3] and carried out a limited review of ICR data from NSPS furnaces and lime kilns in order to identify data quality issues. More details on the NCASI analysis and associated comments can be found in Attachment A. The following conclusions are reiterated here.

1. ***EPA's approach in analyzing COMS and CEMS data does not adequately support the proposed changes in monitoring allowances*** – In general, EPA evaluated the performance of recovery furnaces and lime kilns, against the proposed (TRS and Opacity) monitoring allowances, using annual averages. However, it is inappropriate to assess the ability of NSPS units to comply with a proposed *quarterly* percent exceedance requirement using *annual* exceedance data. Given that percent exceedance is a function of the total number of exceedances in the applicable "period," the use of a longer analysis period has the potential to overstate the unit's performance and yield erroneous conclusions on the ability of furnaces and lime kilns to meet the allowances on a quarterly basis.
   Two specific examples of NSPS-NDCE furnaces exceeding the proposed 1% TRS monitoring allowance are provided in NCASI comments. For instance, EPA's data analysis reports the annual average TRS from a current NSPS recovery furnace (NDCE-WBESP-A) as 0.75 ppm @ 8% O2 for the year 2009 (99th percentile = 2.55 ppm @ 8% O2). During the same year, five exceedances of the 5 ppmdv limit were reported. Data was available from 694 of 730 possible 12-hour averaging periods. On an annual basis, it would appear that this NSPS recovery furnace demonstrates that the proposed standards are achievable (< 1% exceedances – 5/694 = 0.72%). However, 4 of the 5 exceedances occurred in the third quarter and the fifth exceedance occurred in the following quarter. If the proposed standards were applicable to this NSPS unit, the 1% monitoring allowance would be exceeded on a quarterly basis and

[2] Percent of the total number of possible periods of excess emissions in a quarter.

[3] EPA-HQ-OAR-2012-0640 – "Review of Continuous Emission Monitoring and Continuous Opacity Monitoring Data from the Pulp and Paper Information Collection Request Responses Pertaining to Subpart BB Sources," April 5, 2013.

also on a semi-annual basis, when periods of startup and shutdown are included.

2. ***EPA needs to adequately consider data under startup and shutdown conditions before proposing a more stringent monitoring allowance that includes startup and shutdown periods*** – As discussed later in Section VI.B, NCASI's review of ICR data identified instances where *startup and shutdown* data were either excluded from ICR submittals or inappropriately labeled. This has the potential to influence conclusions on the achievability of monitoring allowances, when including startup and shutdown periods.
3. ***Compliance with proposed opacity limits and opacity monitoring allowances may not be adequately demonstrated*** – EPA, in its COMS/CEMS data review of recovery furnaces, stated that only 12 out of 160 recovery furnaces were unable to meet the proposed 20% opacity limit and the 2% monitoring allowance (7 out of 12 were NSPS furnaces) – thereby concluding that compliance at these levels is adequately demonstrated. As discussed in Item 1 above, the assessment of performance using annual averages may have overstated performance and influenced these conclusions. A thorough review of NSPS unit performance that (a) includes quality assurance of all startup/shutdown data, and (b) is carried out using the same averaging time as proposed in the standard would be needed to support the "adequately demonstrated" conclusion. Given the extensive nature of the performance data and the relatively short comment period, we were not able to complete such an assessment.

Given the above uncertainties in data analysis, EPA should reconsider the proposal to lower the opacity monitoring allowance to 2% and instead consider a higher allowance of 4%, calculated on a semiannual basis, consistent with the reporting requirements under Subpart BB and proposed for Subpart BBa (see 60.288a(a)).

AF&PA agrees with EPA's rationale to leave the PM limits for modified furnaces unchanged. However, EPA's COMS data analysis did not distinguish between new/reconstructed and modified furnaces. Therefore, it is unclear whether compliance with the proposed 20% opacity limit, at the 2% monitoring allowance level, is adequately demonstrated. EPA should, at the minimum, reconsider the opacity monitoring allowance for modified recovery furnaces and set it at 4%, calculated on a semi-annual basis to account for the difference between furnaces.

C. Additional monitoring clarifications and changes needed

Use of Uncorrected TRS Concentrations when Stack Oxygen ≥ 15 percent

AF&PA agrees with EPA's rationale in allowing facilities to use uncorrected TRS concentrations during periods when stack oxygen values are ≥ 15 percent. These high stack oxygen periods are typically indicative of (a) startup and shutdown or (b) transient changes in boiler/lime kiln loading that have not been reflected in air flows. The ability to use uncorrected TRS concentrations mitigates the use of an artificially inflated (and inappropriate) oxygen correction factor.

EPA has, however, limited the applicability of this approach by further stipulating that it can be used only during periods of startup and shutdown where the uncorrected TRS concentrations are below applicable limits (5 ppm for recovery furnaces and 8 ppm for lime kilns). The following operating scenarios exist:

1. Periods of startup and shutdown where uncorrected TRS concentrations are below the respective upper restriction levels (30 ppm and 22 ppm for recovery furnaces and lime kilns, respectively) and stack oxygen concentration is ≥15 percent.
2. Limited normal operating periods where uncorrected TRS concentrations are below the respective upper restriction levels (30 ppm and 22 ppm for recovery furnaces and lime kilns, respectively) and stack oxygen concentration is ≥15 percent.

An example scenario illustrating item 1 above is identified in Table 3 of NCASI comments in Attachment A. EPA concludes in the COMS/CEMs background document[4] that brief spikes in recovery furnace TRS concentrations (> 5 ppm) occurred during startup/shutdown periods and that the proposed upper restriction of 30 ppm adequately encompasses these spikes, after addressing extreme-value outliers. Therefore, given that spikes greater than 5 ppm do occur during startup and shutdown periods, it is only logical to allow the use of uncorrected TRS concentrations for these instances (uncorrected values below upper restriction level AND stack oxygen > 15%). This option would be of limited use if TRS "limits" (as opposed to "upper restriction levels") are stipulated as a threshold for applicability.

[4] EPA-HQ-OAR-2012-0640 – "Review of Continuous Emission Monitoring and Continuous Opacity Monitoring Data from the Pulp and Paper Information Collection Request Responses Pertaining to Subpart BB Sources," April 5, 2013.

The scenario identified in Item 2 above (normal operation) also can occur. Given that EPA is proposing a standard that includes all operating periods, including startup and shutdown, EPA should allow the use of this approach for all operating periods when the uncorrected TRS concentration is below the applicable upper restriction level and stack oxygen ≥ 15%.

Procedure to Calculate 12-hr Corrected TRS Concentrations

AF&PA seeks clarification on the procedure used to calculate the 12-hr corrected TRS concentrations used to demonstrate compliance with (a) the applicable TRS limits and (b) the applicable "upper restriction level" during periods when the monitoring allowance is invoked. The need to consider uncorrected TRS concentrations during periods when stack oxygen levels are ≥ 15 percent is another reason for requesting this clarification.

The currently proposed procedure in §60.284a (c)(1) involves (a) calculating the 12-hr uncorrected TRS concentrations, (b) calculating the corresponding 12-hr oxygen concentrations, and (c) carrying out the oxygen correction on the 12-hr average. §60.284(e)(3) states that "If the measured TRS concentration uncorrected for oxygen is less than the applicable…..during periods of startup or shutdown when the stack oxygen concentration is 15 percent or greater, then the Administrator will consider the TRS average to be in compliance." A procedure that performs the oxygen correction on 1-hr uncorrected TRS data, and subsequently uses hourly corrected values to calculate the 12-hr average may be more appropriate given this new oxygen correction requirement. This procedure for calculating the corrected 12-hr TRS concentrations described in NCASI comments provided in Attachment A involves the following steps:

1. Compute 1-hr averages of uncorrected TRS concentrations
2. Calculate the 1-hr averages of stack oxygen concentrations
3. Skip to step 5 if the uncorrected 1-hr average TRS concentration is < the applicable TRS limit[5] AND the 1-hr stack oxygen ≥ 15 percent
4. Carry-out the oxygen correction according to equation in §60.384a (c)(1)(iii), if the 1-hr stack oxygen in < 15% to obtain the corrected 1-hr TRS concentration. Skip to step 6.
5. Use uncorrected 1-hr TRS concentration to calculate the 12-hr block average.
6. Repeat steps 1 through 5 for each hourly average in the 12-hr block
7. Roll-up the hourly averages to calculate the 12-hr block average concentration.

[5] AFPA proposes that EPA modify this to the TRS upper restriction level

The procedure outlined above will helpstreamline the calculations required to demonstrate compliance with the 12-hr block average TRS standard, while accommodating the need to comply with upper restriction levels and the need to use uncorrected TRS values in certain instances. This procedure could be added as an option in 60.284(c)(1).

Use of TRS measurements above instrument span (30 ppmdv) for compliance calculations

EPA also should clarify the procedure for reporting and treatment of uncorrected TRS concentrations that exceed the span value for the instrument (30 ppmdv). One suggested approach would be to (a) use uncorrected TRS measurements up to 60 ppmdv (2 times instrument span) while calculating the 1-hr uncorrected averages and (b) report all measurements > 60 ppm as 60 ppm. This approach minimizes the use of extreme-value data that typically have high levels of measurement uncertainty.

Need for Minimum Data Availability Provisions

The rule requires calculation of 12-hour block average TRS concentrations for the two consecutive periods of each operating day and 3-hour block averages for several parameters. Monitoring is not required during startup and shutdown of affected sources when TRS gases are not being fired in an incinerator, when black liquor is not being fired in a recovery furnace, or when lime mud is not being fired in a lime kiln.

For purposes of demonstrating compliance, these 12-hour and 3-hour block average "periods" are fixed (12 midnight to 12 noon and vice-versa), i.e., the start of the 12-hr block does not coincide with equipment startup. Facilities need flexibility to be able to startup and shutdown in line with process demands. If a recovery furnace is starting up and begins firing black liquor at 11:00, there is only one hour of data that will be used to calculate the 12-hour block average TRS concentration. If the operation is not stable such that TRS emissions are below 5 ppm, that one operating hour will result in excess emissions for that 12-hour average. Similarly, if a source starts up at 12:00, begins firing black liquor or lime mud, and then operators need to shut the source down within an hour or two because operations are not stable and emissions are greater than 5 ppm, one operating hour will result in excess emissions for that 12-hour average. Because EPA has proposed to apply the standards at all times, sources will no longer be able to rely on the NSPS General Provisions to excuse excess emissions during periods of SSM. Therefore, to address these situations, EPA should establish that a 12-hour TRS block average must contain at least 8 hours of data and a 3-hour block average temperature must contain at least 2 hours of data.

Black Liquor Oxidation Systems

The reference to temperature monitoring for incinerators controlling emissions of black liquor oxidation systems in 60.284a(b)(1) and 60.287a(b)(3) should be removed because NSPS BBa does not require control of black liquor oxidation systems.

Combustion Device Monitoring

Most facilities control TRS emissions from affected digesters, evaporators, brownstock washers, and condensate strippers by ducting the exhaust gases to a combustion device. If the gases are ducted to a stand-alone incinerator, temperature monitoring is used to ensure the device is operating at a temperature of at least 1200°F. If the gases are ducted to a combustion device such as a lime kiln, recovery furnace, or power boiler, they are injected either with the primary fuel, with the combustion air, or into the flame zone. The same emissions control scheme is used for HAP emissions control from these sources under MACT Subpart S. Subpart S does not require temperature monitoring when the gases are controlled in a lime kiln, recovery furnace, or power boiler per 63.443(d)(4). EPA should make the clarification in NSPS Subpart BBa that temperature monitoring is only required when TRS control is achieved in a standalone incinerator. As indicated in the 1983 NSPS Review, there is no need to monitor combustion temperature from devices other than an incinerator because these devices normally operate at temperatures higher than 1200°F.[6]

This clarification can be made as follows:

> *60.284a(d)(3)(ii): All 3-hour block averages during which the combustion temperature at the point of incineration is less than 650°C (1200°F), where the provisions of 60.283a(a)(1)(iii) apply <u>and an incinerator is used as the combustion device</u>.*
>
> *60.287a(b)(3) Records of the <u>incinerator</u> combustion temperature at the point of incineration of effluent gases which are emitted from any digester system, brownstock washer system, multiple effect evaporator system, ~~black liquor oxidation system,~~ or condensate stripper system where the provisions of 60.283a(a)(1)(iii) apply <u>and an incinerator is used as the combustion device</u>.*

We support EPA's proposed incinerator temperature monitoring provisions at 60.284a(c)(2) that require 3-hour averages for determining compliance status, as this approach is required in MACT Subpart S.

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[6] EPA-450/3-83-017, Review of New Source Performance Standards for Kraft Pulp Mills, September 1983, page 9-2.

TRS and Oxygen Monitoring Editorial Changes

- The following clarification should be made under 60.284a(c)(1)(ii): change the reference from "paragraph (c)(1) of this section" to "paragraph (c)(1)(i) of this section."
- The following clarification should be made under 60.284a(c)(1)(iii): C_{meas} = the measured 12-hour average concentration uncorrected for oxygen.
- 60.284a(e)(1)(ii) should allow average total secondary power for recovery furnace ESPs as (iv) allows it for lime kiln ESPs.
- 60.384a(e)(i) and (iii) should be revised to indicate "12-hour average" TRS concentration.

VI. SSM Provisions

The proposed rule contains a number of changes that affect mills' compliance obligations during periods of startup, shutdown, and malfunction (SSM). For the most part, those changes are not the result of EPA's assessment of developments concerning demonstrated control technology for kraft pulp mills, but rather an expression of EPA policy preferences that are at odds with 40 years of EPA interpretation and application of CAA section 111. For the reasons described below, AF&PA objects to those proposed changes.

AF&PA is familiar with and supports comments being filed on this proposed rule by the SSM Coalition, which comments are incorporated herein by reference. We also provided extensive comments during the MACT Subpart S Risk and Technology Review related to the necessity of having provisions that address startup, shutdown, and safety-related venting for pulp mill sources that we have included in Attachments B and C of these comments.

A. EPA is not Justified in Eliminating the Exemption for SSM Events Meeting Certain Criteria

The biggest change concerning SSM events is EPA's proposal to reverse long-standing practice and current NSPS regulations by eliminating the existing exemption for SSM events that meet certain criteria. For the past 40 years, EPA has recognized that often it is unreasonable to require sources to meet technology-based emission standards, such as NSPS promulgated under CAA section 111, during SSM periods. Accordingly, 40 C.F.R. § 60.8(c) provides that "emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction [shall not] be considered a violation of the applicable emission limit unless otherwise

specified in the applicable standard." Other provisions require facilities to keep records of the occurrence and duration of any SSM event and to report to EPA a periods of excess emissions that occur during SSM events (or that no excess emissions occurred). 40 C.F.R. § 60.7(b), (c)(2), (c)(4). When EPA promulgated the emission limitations currently contained in Subpart BB, it was with the understanding that those emissions limitations would not apply during periods that qualified as SSM, as defined in 40 C.F.R. § 60.2.

In the proposed rule, there is nothing explicitly stating that the above-cited regulations in the General Provisions would not apply to Subpart BBa. This apparently is what EPA intends to accomplish, however, by adding language, in proposed sections 60.282a(b) and 60.283a(b), that: "The standards in this section apply at all times." See 78 Fed. Reg. at 31,328-29. This proposed action is not only unclear, but it is directly contrary to past EPA interpretations of the statute and of the operative facts.

CAA section 111(a) requires that NSPS be "achievable" with the "best" emission control technology," taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impact and energy requirements," that has been "adequately demonstrated." NSPS that will cause facilities to be in noncompliance, due to unavoidable variation in emissions associated with startup, shutdown, and malfunction, do not meet those statutory criteria. The courts have been explicit about this. For example, in *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 398 (D.C. Cir. 1973), a decision reviewing standards under CAA section 111, the D.C. Circuit recognized the concern that "'start-up' and 'upset' conditions, due to plant or emission device malfunction, is an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated." See also *id.* at 399. Similarly, in *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 432 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974), another section 111 case, the court held that SSM provisions are "necessary to preserve the reasonableness of the standards as a whole." *Id.* at 433. In *National Lime Ass'n v. EPA*, 627 F.2d 416 (D.C. Cir. 1980), another case reviewing emission standards promulgated under CAA section 111, the court held that the CAA requirement that NSPS be "achievable" means that the standards must be capable of being met "under most adverse circumstances which can reasonably be expected to recur …." *Id.* at 431 n.46. *AF&PA is not aware of a single court decision that reaches a different conclusion with respect to NSPS.* Thus, EPA's proposal to simply delete long-standing provisions accommodating excess emissions during SSM events is directly contrary to judicial precedent.

EPA offers several purported justifications for abandoning its past interpretations of CAA section 111 and acting directly contrary to established judicial precedent. None of them withstands scrutiny.

First, EPA suggests that it is appropriate to remove the 40 C.F.R. § 60.8(c) SSM exemption from applicability to Subpart BBa because the statutory definition of "emission limitation" and "emission standard" specifies a requirement that limits air pollutant emissions "on a continuous basis." There are multiple problems with that argument:

(1) The qualifier that an emission limitation must apply on a continuous basis was adopted to preclude the use of intermittent or temporary controls (e.g., controls that operate only during "dirty air" periods), and nothing in the legislative history suggests that Congress intended to overturn existing EPA regulations that recognize the need for relief from otherwise-applicable emission standards during SSM events. *Sierra Club v. EPA*, 551 F.3d 1019, 1027 (D.C. Cir. 2008), *cert. denied*, 130 S. Ct. 1735 (2010), citing *Kamp v. Hernandez*, 752 F.2d 1444, 1452 (9th Cir.1985). See also Conference Report on H.R. 6161 (the CAA Amendments of 1977), H. Rep. No. 95-564 (August 3, 1977) at 129, 172; S. Rep. No. 94-717 (March 29, 1976) at 78.

(2) The "continuous basis" language was inserted into the definition of "emission limitation" in 1977, before the D.C. Circuit's 1980 *National Lime Ass'n* decision affirming the need for NSPS to be achievable even during anticipated SSM events. It also was followed by 30 years of EPA promulgating NSPS that incorporated the SSM exemption in 40 C.F.R. § 60.8(c) and other SSM provisions.

(3) The court decision EPA cites on the "continuous" issue, *Sierra Club v. EPA*, 551 F.3d 1019, 1021, did not say anything about standards of performance under CAA section 111 and the requirement of section 111 that those standards reflect the performance achieved by demonstrated control technologies. Rather, that decision addressed what the Court concluded was a requirement of section 112 that MACT standards be "section 112-compliant" at all times. *Id.* Moreover, the *Sierra Club* decision interpreted the definition of "emissions standard" in CAA section 302(k) not to require "unchanging" standards and to allow EPA to promulgate MACT standards "without necessarily continuously applying a single standard." 551 F.3d at 1021, 1027.

(4) The definition of "emission standard" in CAA section 302(k) does not in any way suggest that the requirement that standards limit emissions of air pollutants on a continuous basis means that the standard must be the same at all times. Moreover, section 302(k) specifically recognizes that this requirement can be met through "any requirement relating to the operation or maintenance of a source to ensure continuous emission reduction" or "any design, equipment, work practice or operational standard

promulgated under" the CAA (hereafter, "work practices"). The current Kraft Pulp Mill NSPS conform to this definition: Although the numerical emission limitations that apply during normal operations do not apply during incidents that meet the definition of SSM, pursuant to 40 C.F.R. § 60.8(c), there are requirements related to the operation and maintenance of the source or work practices that do apply during SSM events. See, e.g., 40 C.F.R. § 60.11(d) (operator "shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions," at "all times, including periods of startup, shutdown, and malfunction").

Secondly, EPA suggests that its position on use of an affirmative defense is supported by a recent Fifth Circuit decision in *Luminant Generation LLC v. EPA*, 714 F.3d 841 (2013). There are many problems with that assertion. For one, the *Luminant* decision addressed EPA's discretion to approve and disapprove State Implementation Plans under CAA section 110; it had nothing to do with establishment of standards achievable with best demonstrated technology under CAA section 111. Secondly, the *Luminant* decision largely dealt with whether EPA's approval of the Texas SSM provisions was consistent with the CAA enforcement authorities in section 113(e), which again does not bear on whether use of the affirmative defense is an adequate substitute for establishing achievable NSPS under section 111. Thirdly, the *Luminant* court sustained EPA's approval of a Texas SIP affirmative defense provision that includes unplanned startup and shutdown events, while EPA takes the position in the proposed Subpart BBa preamble that an affirmative defense is not appropriate for startup and shutdown events. Finally, the *Luminant* decision currently is the subject of a petition for writ of *certiorari* pending before the Supreme Court.

EPA's third claimed justification, which applies only to startup and shutdown ("S/S"), is that affected facilities can in fact meet the emission standards during S/S. For the reasons set forth below and in our previously submitted comments included in Attachments A and B, that conclusion is not factually accurate, and in fact short-term venting of gas streams controlled under the NSPS will be unavoidable during some S/S events. EPA has recognized that it could set alternative emission standards for S/S periods, however, if needed to make the NSPS consistent with the performance achieved by demonstrated control technology. See 78 Fed. Reg. at 31,328; see also, e.g. 77 Fed. Reg. 52,554, 52,558 (August 29, 2012) (same conclusion with respect to NSPS for gas turbines); 75 Fed. Reg. 54,970, 54,991 (September 9, 2010) (establishing different standards to apply to cement plants during S/S). AF&PA demonstrates below that EPA's assumption that mills can meet the numerical and other emission limitations in the proposed Subpart BBa standards at all times during

S/S is inaccurate, and therefore EPA is not justified in eliminating the 40 C.F.R. § 60.8(c) provision for excess emissions during S/S.

EPA's fourth claimed justification for eliminating SSM exemptions and applying the numerical emission standards at all times is that a malfunction exemption is somehow inconsistent with the concept of NSPS based on "the application of the best system of emission reduction." 78 Fed. Reg. at 31,329. EPA asserts that "[n]othing in CAA section 111 or in case law requires" that "emissions that occur during periods of malfunction be factored into development of CAA section 111 standards." *Id.* But as noted above, the plain language of section 111 and the explicit direction of all of the relevant case law is that malfunctions must be accommodated by the NSPS if they in fact are to be achievable when using the best demonstrated control technology on which the NSPS are based. EPA's claim that the technology basis for NSPS incorporates the notion of "operating units in such a way as to avoid malfunctions" and setting emission standards at levels "achieved by a well-performing non-malfunctioning source," *id.*, has no basis in the statutory language or the case law. Rather than setting standards of performance that reflect what is achieved by demonstrated technology, as the statute requires, EPA, by assuring that sources will be in violation of the standards despite installation of the identified control technology, has assured that the proposed NSPS are inconsistent with the statutory criteria for NSPS. See *id.* (recognizing that "even equipment that is properly designed and maintained" can be expected to fail sometimes, and therefore not to achieve the emission limitations EPA is proposing). Far from being "consistent with section 111 and... a reasonable interpretation of the statute," *id.*, EPA's approach to malfunctions disregards congressional intent that NSPS be achievable with demonstrated technology and instead sets limits EPA knows sources will violate even if they install that technology and operate and maintain it properly.

Finally, EPA claims that it would be impracticable for it to establish NSPS that take malfunctions into account, because of the unpredictable nature of malfunctions. *Id.* Of course, EPA has been promulgating NSPS that accommodate SSM events for 40 years, so that protest rings particularly hollow. Specifically, EPA's stated concerns about the difficulty of "accounting for the frequency, degree in duration of various malfunctions," suggesting that EPA could not reasonably collect sufficient scientific data to establish NSPS that take malfunctions into account, *id.*, ignores completely EPA's authority to use operation and maintenance requirements and work practices, which is provided specifically to address such situations. See CAA sections 111(h)

and 302(k). EPA has done so in Subpart BB and should do so in Subpart BBa as well.[7]

EPA's proposal to allow an "affirmative defense" to civil penalties for a malfunction, if the source can meet extensive criteria, does not cure the Agency's failure to set NSPS that are achievable in the first place. EPA has provided no analysis that would supersede its long-standing determination that it is not desirable to rely on enforcement, rather than regulatory language, to address the inability to comply with technology-based standards during SSM events. See 37 Fed. Reg. 17,214, 17,214 (Aug. 25, 1972) (establishing SSM provision in NSPS). The courts have adopted the same view. See *National Lime*, 627 F.2d at 431 n.46 (promised flexibility in enforcement "will not render 'achievable' a [NSPS] which cannot be achieved on a regular basis, either for the reasons expressly taken into account in compliance determination regulations (here startup, shutdown and malfunction), or otherwise."). See also *Marathon Oil Co. v. EPA*, 564 F.2d 1253, 1273 (9th Cir. 1977) (EPA's statement that it would not take enforcement action against sources that exceeded effluent limitations because of upset events was "not an adequate response" to the argument that standards that cannot be met during unavoidable upsets fail to reflect available technology).[8]

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[7] EPA suggests that its position is supported by *Weyerhaeuser Co. v. Costle*, 590 F.2d 1011 (D.C. Cir. 1978). But that opinion: (a) involved a Clean Water Act "technology-forcing" requirement that is different from the best demonstrated technology requirement of CAA section 111; (b) was issued long before the D.C. Circuit concluded in *NRDC v. EPA,* 859 F.2d 156 (D.C. Cir. 1988) that the Clean Water Act technology-based effluent limitations must include an upset provision to address circumstances where compliance with effluent limitations is impossible through no fault of the permittee; and (c) in any event speaks to highly unusual events ("'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication, or insanity") rather than to anticipated inability of identified control technology to meet specified emission limitations 100% of the time. See 590 F.2d at 1058. Moreover, the fact that there may be certain kinds of malfunctions that EPA could not reasonably account for in the NSPS does not in any way demonstrate that EPA is justified in ignoring all types of malfunctions when it establishes the standards.

[8] AF&PA is not suggesting that EPA lacks authority to include an affirmative defense provision in NSPS, but rather that doing so is not an adequate substitute for establishing NSPS that are achievable under anticipated operating conditions in the first place. EPA has broad discretion in how it fashions NSPS. EPA can carve out types of sources or circumstances that do not have to meet the emission limitations that would otherwise be imposed by an NSPS, and it frequently has. See, e.g., exemptions for engines in certain uses in the NSPS for Compression Ignition Internal Combustion Engines, 40 C.F.R. § 60.4200; exemption from control requirement for brownstock washers at mills where controls would be technologically or economically infeasible, 40 C.F.R. § 60.283. Using work practice standards under section 111(f) is also a way that EPA sometimes has provided relief from compliance with certain

In any event, EPA has established criteria for a source to qualify for the affirmative defense that, if interpreted literally, would make it nearly impossible for a source to take advantage of the affirmative defense, even if the source took all appropriate steps before, during, and after the malfunction. (Those shortcomings of the criteria for the affirmative defense are set forth in detail in the comments of the SSM Coalition.) Perhaps for that reason, EPA estimates that there will be no more than two instances of a mill seeking to avail itself of the affirmative defense during the first three years after the Subpart BBa standards are promulgated! See 78 Fed. Reg. at 31,333. That alone should demonstrate that the affirmative defense does not in any way satisfy the requirement that NSPS be set at a level that facilities will be able to meet with the identified control technology.

Likewise, EPA's plan to limit the affirmative defense to civil penalties only renders the affirmative defense inadequate for the purpose EPA has claimed. Since injunctive relief would be available even where a malfunction was unavoidable despite installation and operation of the identified "best" control technology, mills still would be subject to enforcement action, including citizen suits, and liability for remedial action and citizens group attorneys' fees, under emission standards that are supposed to be achievable using demonstrated technology. For the affirmative defense to provide relief from violations that were unavoidable with the specified technology, it cannot be limited to civil penalties alone.

B. The 2011 ICR did not include data during *startup and shutdown* <u>in all cases</u>. Therefore, EPA may not have adequately considered all operating scenarios and data associated with startup and shutdown conditions in its analysis

NCASI's focused review of NSPS data has identified Instances where facilities either excluded[9] or mis-labeled data collected during *startup and shutdown* periods. This exclusion of relevant data could extend to a larger subset of evaluated sources, is a cause for concern, and has the potential to lead to wrong conclusions about *startup and shutdown* periods. As discussed earlier, there also is the potential for

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numerical standards. Contrary to objections that some have raised to affirmative defense language in NESHAPs, EPA does not usurp the role of the courts in enforcing emission standards when EPA includes an affirmative defense provision in those emissions standards; it simply is designing those emission standards so that they will, in EPA's judgment, meet the letter and intent of the relevant statutory requirement.

[9] In many cases, state reporting requirements require facilities to exclude S/S data from periodic reports.

overstatement of unit performance as a result of the use of *annual* data in assessing compliance with a proposed *quarterly* allowance. The potential exclusion of *startup and shutdown* data from ICR datasets may further impact the "adequately demonstrated" conclusion associated with the monitoring allowances.

As described earlier, it is AF&PA's position that EPA is not justified in eliminating the exemption for SSM events in Subpart BBa. Additionally, the NCASI analysis suggests that data related to *startup and shutdown* may not have been adequately considered in this proposal in all cases. Therefore, the underlying conclusions about performance during *startup and shutdown* conclusions are also potentially in error.

C. It is Not Feasible to Comply with the Standards at All Times

EPA has added language at 60.282a(b) and 60.283a(b) that states "the standards in this section apply at all times." The TRS emission standard that applies to affected digester systems, brownstock washer systems, multiple-effect evaporator systems, or condensate stripper systems is (a) 5 ppm TRS or (b) combustion in a lime kiln, recovery furnace, boiler, or incinerator. Exhaust gases from these systems are collected and conveyed to a combustion device in order to meet the standard. The current NSPS Subpart BB states that excess emissions occur when there is a period in excess of 5 minutes where these gases are not combusted at a temperature of at least 1200°F (see 60.284(d)(3)). Excess emissions that occur during periods of SSM are recorded and reported according to 40 CFR 60.7. These systems are also subject to MACT standards at 40 CFR 63, Subpart S. Subpart S allows periods of excess emissions up to 1 percent of the time for low-volume, high-concentration (LVHC) pulp mill gas collection systems (e.g., digester, evaporator, and stripper off-gases) and up to 4 percent of the time for high-volume, low-concentration (HVLC) gas collection systems (e.g., brownstock washer gases), including periods of SSM.

The proposed Subpart BBa is more stringent than either MACT Subpart S or NSPS Subpart BB, as EPA has added language to BBa that states the standards apply at all times, and changed the definition of excess emissions as all 3-hour block averages during which the combustion temperature is less than 1200°F (60.284a(d)(3). There are no provisions in this standard specifically addressing short periods of safety-related venting. Best available technology includes unavoidable periods wherein all vent gases cannot be routed to the control device for safety reasons and/or when the control device is inoperable or necessarily operating at a reduced rate due to a malfunction. More detail is provided in our previously submitted comments located in Attachments B and C.

In addition, EPA should add ", as provided in sections 60.284a and 60.285a." at the end of the statements in proposed sections 60.282a(b) and 60.283a(b) that "The standards in this section apply at all times." This is necessary to avoid confusion about EPA's intent in adding these short, unqualified statements to the sections describing the PM and TRS standards. It may be obvious that the monitoring and performance testing sections that follow, including provisions defining excess emissions, govern implementation of the emission limitations, but the wording in proposed sections 60.282a(b) and 60.283a(b) might be misinterpreted. (For example, as proposed, section 60.283a might be misunderstood to impose TRS limitations on recovery furnace emissions even during periods when black liquor solids are not being fired.)

D. EPA Should Adopt the Excess Emissions Provisions in MACT Subpart S for Digesters, Brownstock Washers, Evaporators, Strippers Covered by NSPS Subpart BBa

The excess emission provisions in the MACT Subpart S regulations reflect EPA's careful determination, after years of study of a large quantity of emissions information and public comments, that the MACT "floor," representing the emissions of the "best performers," includes emissions during unavoidable periods of releases of uncontrolled or partially controlled pulping process vent gases (See 63 Fed. Reg. 18504, 18529 (April 15, 1998)). "EPA established appropriate excess emission provisions to approximate the level of backup control that exists at the best-performing mills and the associated period of time during which no control device is available." *Id.* After "an analysis of the public comments and the available data regarding excess emissions and the level of backup control in the industry," EPA determined that the "best-performing mills achieve a one percent downtime in their LVHC system control devices" and "best-performing mills achieve a four percent downtime in the control devices used to reduce emissions from their HVLC system to account for flow balancing problems and unpredictable pressure changes inherent in HVLC control systems." *Id.* "The allowances address normal operating variations in the LVHC and HVLC system control devices for which the equipment is designed. The variations would not be considered startup, shutdown, or malfunction under the Part 63 General Provisions…." (See 63 Fed. Reg. 18530).

EPA adopted the excess emission provisions after reviewing extensive data from continuous monitoring systems and considering industry comments that although some mills had backup combustion devices as part of their LVHC control system, venting of noncondensible gases (NCG) is an essential safety practice (because of their explosion hazard) even for those systems with backup control devices, since the startup of, and transfer of vent gases to, the backup controls cannot be immediate or

automatic for safety reasons, and operating variability in the control devices themselves was unavoidable for process and other reasons. See, e.g., Pulp, Paper and Paperboard Industry – Background Information for Promulgated Air Emission Standards – Final EIS, EPA-453/R-93-050b (October 1997) ("BID") at 4-81, 4-82 to 4-84; AF&PA April 18, 1994 comments on the proposed MACT standards for Pulp and Paper Mills, p. MACT-61 (events resulting in venting of NCGs are "integral to process variability," and combustion devices will "predictably" not perform at their design efficiency " some small percentage of the time, even when they are being operated properly and all equipment is in order"); id. p. MACT-173-74. For HVLC systems, few mills had backup controls that could handle the large volume of vent gases, so any standard that required the use of backup devices would have been beyond the MACT "floor" and would not have been cost-effective due to the low concentration of pollutants in the large gas stream (See 63 Fed. Reg. 18529; BID at 4-81 to 4-82; AF&PA April 18, 1994 comments at MACT-61 (degree of venting allowance needed is "independent of the availability of backup combustion devices because of the safety and engineering concerns"); *id.* at MACT-174 (backup combustion devices for HVLC systems could be an additional cost of $1 billion).

In short, the MACT determinations that EPA made when promulgating the Subpart S emission standards correctly concluded that best available technology includes unavoidable periods wherein all vent gases cannot be routed to the control device, and/or when the control device is inoperable or necessarily operating at a reduced rate. The Subpart S emission standards (including the excess emission provisions) were designed to reflect the performance of the MACT technology and the actual performance of the "best performing" mills. There have been no technology developments for new/modified sources that would change the conclusions reached under Subpart S. Without any excess emission provisions, the Subpart BBa emissions standards would impose limitations not achieved even by the "best performers" and not demonstrated as achievable at any facility.

Provisions for a small amount of LVHC and HVLC system venting and stripper downtime were developed as part of the MACT "floor," based on the fact that even the best-performing units could not meet the standards at all times. As the technology for the collection and treatment of HAPs under Subpart S has not changed, neither has the capability for mills to operate without needing these provisions. These provisions are necessary due to process variability and not for situations defined as startup, shutdown, or malfunction (SSM). These events generally are not due to situations where some equipment has broken down and must be repaired to correct the situation, but are due to process variability and safety interlocks which have caused a situation that requires a release.

LVHC Systems

LVHC NCG gases (e.g., those from digesters and evaporators) are potentially explosive and cannot be burned safely without supplemental fuel. Most mills have both a primary and back-up control device[10] for the treatment of LVHC gases. These gases must be incinerated with support fuel and be interlocked to failsafe on loss of support fuel, combustion air, and/or boiler load. The flame safety system will not permit the gases to be admitted until the burner is operating on supplemental fuel and ignition is proven. Therefore, for gases to be introduced into any control device, several conditions, also known as permissives, must be met and the system has a series of interlocks that will not allow the introduction of gases unless all conditions are satisfied. These conditions are required for both safety and protection of process equipment. The safety interlocks are required by both Factory Mutual Insurance and the National Fire Protection Association for burning of these non-condensable gases. Also, when these gases are burned in a recovery furnace, there are safety guidelines issued by the Black Liquor Recovery Boiler Advisory Committee (BLRBAC).

HVLC Systems

The HVLC system (used to collect gases from sources such as brownstock washers) is similar to the LVHC system in causes of venting events. "The best-performing mills achieve a four percent downtime in the control devices used to reduce emissions from their HVLC system to account for flow balancing problems and unpredictable pressure changes inherent in HVLC systems" (See 63 Fed. Reg. Vol. 72 at 18529 (April 15, 1998)). The main difference is that most HVLC systems do not have back-up control devices. Therefore, when boiler/firing permissives prevent the incineration of these gases, the mill must decide if emissions will be best minimized by waiting for the control device to become available or shutting down the HVLC sources.

TRS Emissions During Startup, Shutdown, and Safety Venting

For each type of release, it is not possible to estimate emissions on a site- or event-specific basis. Emissions will vary based on the cause, location, and source of the release. Emissions will vary not only between mills and sources but between the same sources at the same mill under different circumstances. NCASI has developed limited data sets for main vents (vents immediately prior to the control device that include gases from all collected sources) under normal operations. However, site-specific data cannot be collected for the releases listed above as the events cannot be anticipated,

[10] Common control devices for LVHC gases include power boilers, lime kilns, stand-alone incinerators, and recovery furnaces.

the events are typically short in duration, and it is unsafe to perform sampling. Therefore, it is not possible to develop or suggest a TRS standard that might apply during these periods.

For Subpart S, EPA decided to develop MACT "floors" on a unit (i.e., system) basis." See EPA-453/R-93/050b, October 1997, page 4-6.

> Development of a numerical emissions standard (other than tracking vent time) is not feasible due to limitations in technology. As discussed above, there are no data available to quantify site-specific emissions from the vents of LVHC and HVLC systems.

Procedures to Minimize TRS Emissions During Startup, Shutdown, and Safety Venting

Under Subpart S, mills were required to develop SSM Plans, and the same procedures are followed for sources subject to NSPS Subpart BB even though SSM plans are not required. Mills use these plans and standard operating procedures to define the work practices mills must follow to minimize emissions during a release. For example, during extended steam stripper downtimes (that exceed the buffering capacity of the condensate collection tank), many facilities route their condensates to the secondary wastewater treatment system. Depending on process and system design, mills also monitor the location and duration of releases from NCG systems either by detecting changes in pressure (most popular), valve position, temperature at the vent location, or flow meters. Facilities have instituted standard operating procedures and corrective actions to minimize these intermittent venting periods and record this information either electronically or in log books and report events, causes, and corrective actions.

E. Additional Changes Needed to Accommodate Startup and Shutdown

EPA has not proposed alternate standards during periods of startup and shutdown, but has proposed some adjustments and clarifications to accommodate startup and shutdown periods for incinerators, recovery furnaces, and lime kilns. EPA has clarified that the TRS limits for recovery furnaces and lime kilns only apply when black liquor or lime mud is being fired. EPA has also allowed the use of uncorrected TRS concentrations during startup and shutdown when the O2 concentration is greater than 15 percent. We support these provisions and believe they are necessary. In addition, operating parameter limits apply during startup and shutdown. However:

- Because incineration devices must warm to 1200F during control startup prior to firing TRS gases (and subsequently cool to below 1200F during control shutdown), the EPA is proposing to allow facilities to omit 5-minute recorded temperature measurements from the 3-hour block averages when no TRS emissions are fired. This means that when the incinerator is not burning TRS (e.g., during incinerator warm-up and cool-down periods when TRS gases are not being burned or when an alternative control device is used), the low temperature does not constitute a violation.
- To address the need for ESPs to warm to a specified temperature before full power is applied to the transformer-rectifier set, the EPA is proposing to define excess emissions as ESP parameter measurements below the minimum requirements during times when BLS or lime mud is fired (as applicable).
- The EPA is also proposing language that would allow affected units to use only wet scrubber liquid flow rate (or liquid supply pressure) to demonstrate compliance during periods of startup and shutdown because pressure drop is difficult to achieve during these periods.

We believe it is appropriate for EPA to acknowledge that operations of control equipment are different during periods of startup and shutdown than during periods of steady state, normal operation and the proposed monitoring provisions that accommodate these differences in operation are appropriate. However, additional provisions are needed to more fully account for startup and shutdown periods.

Startup and ESPs

PM emissions from recovery furnaces (and some lime kilns) are controlled using ESPs. As proposed, Subpart BBa will not require compliance with the opacity standard until black liquor or lime mud is being fired, which provides time for the operators to warm up the equipment on auxiliary fuel, such as fuel oil or natural gas. The ESP cannot practically be engaged until a certain flue gas temperature is reached. Premature starting of this equipment will lead to short-term stability problems that could result in unsafe actions and longer term degradation of ESP performance due to fouling, increased chances of wire damage, or increased corrosion within the chambers. Vendors providing this equipment incorporate these safety and operational concerns into their standard operating procedures.[11]

During periods of startup, auxiliary fuel (e.g., fuel oil or natural gas) is introduced to the furnace or kiln and the ESP warms up on a designated curve that could last for a few

[11] See Appendix I of AF&PA's August 23, 2010 comments on the June 4, 2010 proposed Boiler MACT rule for an excerpt of an ESP operational manual.

hours. Some ESPs have oxygen sensors and alarms that shut down the ESP at high flue gas oxygen levels to avoid a fire in the unit. The oxygen level is typically high during startup, so the ESP may not engage due to these safety controls until more stable operating conditions are reached. When the furnace or kiln is started on residual oil, the ESP cannot be engaged until a certain temperature is reached to avoid fouling the plates.

Operators have a financial incentive to minimize the time spent in startup. When units are starting up, they are not operating in the most efficient mode, auxiliary fuel is being burned, and the process is not operating optimally. Therefore, furnaces and kilns are started up as expeditiously as possible, but safety concerns cannot be ignored, and proper procedures must be followed. EPA is correct in applying the opacity standard only after black liquor or lime mud is introduced into the furnace or kiln. However, the ESPs are operated using a power management system to ensure the most efficient mode of operation. The efficient functioning of an ESP means minimizing power consumption and maximizing dust collection. These automated power management systems sense the amount of loading and adjust the amount of current applied accordingly, based on the spark rate. Therefore, at low loads during startup and shutdown when black liquor or lime mud is being fired at less than normal operation, the secondary current may not be within the range achieved during the last performance test, but the ESP is still operating optimally. The first 12-hour block average secondary current or total secondary power reading could be less than the established operating parameter range, but the PM emissions and opacity could below the standards.

Therefore, we request that EPA exclude from the definition of excess emissions all 12-hour average measurements of secondary current or total power during startup and shutdown that are less than the site-specific operating parameter limits as it has done for scrubber pressure drop (see 60.284a(d)(4)(ii) and (5)(ii)). Given the difficulties associated with maintaining steady secondary current, and extending the logic behind allowing liquid flow rate (as opposed to pressure drop) for scrubbers during startup and shutdown, EPA also should allow facilities to monitor only secondary voltage during startup and shutdown.

Longer Averaging Times

In addition to incorporating provisions that address the startup and shutdown issues raised above, EPA could also incorporate a longer averaging time to the various emission standards (e.g., 24-hour average) to better account for short safety venting episodes and short excursions during startup and shutdown. Second, the definition of excess emissions as a period in excess of 5 minutes where gases are not combusted at temperature in Subpart BB (see 63.284(d)(3)(ii)) should be retained in Subpart BBa.

EPA has not provided a sufficient rationale for its elimination. However, a longer averaging time or a 5-minute allowance will not be sufficient to account for the time needed to safely startup digester, evaporator, stripper, and brownstock washer systems and thus other changes are necessary as discussed above.

VII. Costs and Impacts

EPA has proposed to change the new/reconstructed source PM limits to be equivalent to the MACT Subpart MM emission limits for recovery furnaces and lime kilns. There are no costs associated with this change. For modified lime kilns and recovery furnaces, there would be a cost associated with lowering the PM limits below the current MACT Subpart MM PM limits for existing lime kilns and recovery furnaces. It is neither technically or economically feasible to lower TRS limits.

EPA is not changing the PM emission limits for new smelt tanks because it is not cost effective to do so. It is important to understand that smelt tanks are regulated differently under NSPS and MACT. A smelt tank becomes subject to the NSPS upon construction, reconstruction, or modification. The current Subpart BB NSPS PM limit is 0.2 lb/TBLS and the TRS limit is 0.033 lb/TBLS, and these limits apply to both new/reconstructed and modified sources. The MACT PM limit for existing smelt tanks is 0.2 lb/TBLS and the MACT Subpart MM PM limit for new smelt tanks is 0.12 lb/TBLS. However, under the MACT rule, the recovery furnace and its associated smelt tank are one affected source, so if a facility replaces a smelt tank but not the associated recovery furnace, the replacement smelt tank is **not** a new source under the MACT but **is** a new source under NSPS BB. Due to this difference in the definition of affected source, there is a cost associated with lowering the NSPS PM limit for modified and reconstructed smelt tanks to the level of the new source MACT limit.

AF&PA has used information provided by EPA, knowledge of industry practices, and previous control cost studies specific to the pulp and paper industry to estimate the feasibility and impacts of lowering the NSPS limits for Subpart BBa. Our analysis indicates that it is not feasible to lower the TRS emission limits and it is not cost effective to lower the PM emission limits.

A. Smelt Tank Cost Analysis

Emissions from smelt tanks are typically controlled by some type of wet scrubber. The systems used range from simple water sprays with mesh pads to wet fan impingement scrubbers to venturi scrubbers, and the control efficiencies vary from unit to unit. Impacts of lowering the PM limit can be examined using various scenarios. The cost

effectiveness of additional smelt tank controls will depend on the unit's size, existing emission rate, future NSPS limit, and performance of existing control equipment. Modified or reconstructed units may have controls that would not need to be replaced at the current NSPS level, but may need replacement in order to meet a lower NSPS level.

Scenario 1: A facility performs a project that is considered a modification or reconstruction and triggers NSPS applicability for a smelt tank. The smelt tank is equipped with a scrubber that complies with a 0.2 lb/TBLS PM limit but would not comply with a lower limit such as 0.15 or 0.12 lb/TBLS. In the current case, the scrubber would not be replaced. In a future case where the NSPS limit was lowered, the scrubber would have to be replaced. Therefore, the cost of lowering the NSPS is the cost of a new scrubber. The table below presents example calculations of cost effectiveness for 2 sizes of smelt tanks and 2 levels of NSPS revision assuming the modified smelt tank's current emissions are 0.18 lb/TBLS. Note that the annual cost only reflects the annualized capital cost of a new scrubber and assumes the operating costs would be the same to simplify the analysis.

Scenario	Throughput		Current Emission Rate		Future Emission Rate		PM reduced, tpy	Annual Cost	$/ton
1a. Small SDT, NSPS to 0.15	40	TBLS/hr	0.18	lb/TBLS	0.15	lb/TBLS	5.26	$313,828	$59,708
1b. Small SDT, NSPS to 0.12	40	TBLS/hr	0.18	lb/TBLS	0.12	lb/TBLS	10.51	$313,828	$29,854
1c. Large SDT, NSPS to 0.15	70	TBLS/hr	0.18	lb/TBLS	0.15	lb/TBLS	9.20	$439,050	$47,733
1d. Large SDT, NSPS to 0.12	70	TBLS/hr	0.18	lb/TBLS	0.12	lb/TBLS	18.40	$439,050	$23,867

Scenario 2 (used by EPA): A facility performs a project that is considered a modification or reconstruction and triggers NSPS applicability for a smelt tank. The current smelt tank scrubber either cannot meet the current 0.2 lb/TBLS limit, or it is in need of replacement, so the facility needs to install a new scrubber as part of the project. The impact of reducing the NSPS limit is the difference between the cost of the scrubber that will achieve compliance with 0.2 lb/TBLS and the cost of the scrubber that will achieve compliance with a lower level like 0.12 lb/TBLS. For purposes of costing, we have compared the "good" and "best" scrubbers in the September 2001

Emission Control Study prepared by BE&K Engineering for AF&PA, with appropriate updates to 2012 dollars and scaling for size.

AF&PA would like to point out that scenario 2 would be much less likely to occur, as a facility would be more likely to upgrade/retrofit newer equipment that already complies with the NSPS limit rather than older equipment that does not. However, we have included this scenario for completeness as EPA has examined this type of scenario.

Scenario	Throughput		Current NSPS Emission Rate		Future NSPS Emission Rate		PM reduced, tpy	Annual Cost	$/ton
2a. Small SDT, NSPS to 0.15	40	TBLS/hr	0.2	lb/TBLS	0.15	lb/TBLS	8.76	$20,204	$2,306
2b. Small SDT, NSPS to 0.12	40	TBLS/hr	0.2	lb/TBLS	0.12	lb/TBLS	14.02	$20,204	$1,441
2c. Large SDT, NSPS to 0.15	70	TBLS/hr	0.2	lb/TBLS	0.15	lb/TBLS	15.33	$28,394	$1,852
2d. Large SDT, NSPS to 0.12	70	TBLS/hr	0.2	lb/TBLS	0.12	lb/TBLS	24.53	$28,394	$1,158

Scenario 3. A facility installs a new smelt tank to replace an existing smelt tank or reconstructs the smelt tank. New source MACT is not triggered because the facility is not replacing or reconstructing the recovery furnace. If the smelt tank needs a new scrubber as part of the project, the cost is the same as Scenario 2 if the NSPS limit is lowered. If the smelt tank doesn't need a replacement scrubber as part of the project, the cost is the same as Scenario 1 if the NSPS limit is lowered.

Scenario 4. A facility constructs a new smelt tank and recovery furnace. The new smelt tank is subject to new source MACT so changing the NSPS to new source MACT level does not have any associated cost.

Summary

Under Scenario 1, the cost of lowering the NSPS PM limit is very high, and none of the examples evaluated show that additional control is cost effective. Scenario 2 has costs in the low thousands of dollars per ton if a facility were to need a new smelt tank scrubber under the existing NSPS PM limit. An examination of the ICR summary data provided by EPA to AF&PA and the data in NCASI Technical Bulletin 884 indicates that median smelt tank PM emissions are around 0.15 lb/TBLS. Therefore, if most units

can meet the current NSPS limit of 0.2 lb/TBLS, Scenario 1 is much more likely to occur than Scenario 2.

EPA has estimated that 6 smelt tanks will be modified over the next 10 years. If we assume conservatively that 3 of them fall under Scenario 1 and 3 of them fall under Scenario 2, the following table shows two example total cost and total cost effectiveness evaluations, depending on which subsets of Scenarios 1 and 2 are selected.

Example 1		**tons**	
(large units controlled to 0.12 lb/TBLS)	**annual cost**	**reduced**	**$/ton**
3 units under scenario 1d	$1,317,150	55.2	$23,867
3 units under scenario 2d	$85,181	73.6	$1,158
Total	$1,402,331	128.8	**$10,890**

Example 2		**tons**	
(small units controlled to 0.15 lb/TBLS)	**annual cost**	**reduced**	**$/ton**
3 units under scenario 1a	$941,483	15.8	$59,708
3 units under scenario 2a	$60,611	26.3	$2,306
Total	$1,002,094	42.0	**$23,832**

In either example, the total cost effectiveness is greater than $10,000/ton, which confirms EPA's analysis that lowering the smelt tank NSPS PM limit is not cost effective.

B. Lime Kilns Analysis

A lime kiln becomes subject to NSPS BB upon construction, reconstruction, or modification. The NSPS PM limit is 0.066 gr/dscf for kilns burning natural gas (or a mixture of gas and oil) and 0.13 gr/dscf for kilns burning oil. The TRS limit is 8 ppmvd at 10% O_2, and these limits apply to both new/reconstructed and modified sources. The MACT PM limit for existing lime kilns is 0.064 gr/dscf and the MACT PM limit for new lime kilns is 0.01 gr/dscf. EPA has proposed to eliminate the separate oil-fired kiln PM limit and establish a PM limit of 0.064 gr/dscf that is not fuel specific.

Emissions from lime kilns are controlled by either wet scrubbers, ESPs, or both. The wet scrubber provides both PM and TRS control, while the ESP provides a lower level of PM control than a wet scrubber. Kilns with both controls have the lowest PM emissions, and an ESP is needed to achieve the MACT new source PM limit and would be needed for an equivalent NSPS limit. Impacts of lowering the PM limit can be examined using various scenarios. The cost effectiveness of

additional controls will depend on the unit's size, existing emission rate, future NSPS limit, and performance of existing control equipment. Modified or reconstructed units may have controls that would not need to be replaced at the current NSPS level, but may need replacement in order to meet a lower NSPS level.

Scenario 1: A facility performs a project that is considered a modification and triggers NSPS applicability for a lime kiln. The kiln is equipped with a scrubber that complies with a 0.066 gr/dscf PM limit but would not comply with a lower NSPS limit such as 0.02 or 0.01 gr/dscf. In the current case, the scrubber would not be replaced because it meets the current NSPS limit. In a future case where the NSPS limit was lowered, an ESP would have to be installed prior to the scrubber in order to meet the lower limit. Therefore, the cost of lowering the NSPS is the cost of a new ESP. The table below presents example calculations of cost effectiveness for 2 sizes of kilns and 2 levels of NSPS revision assuming the modified kiln's current emissions are 90% of the current NSPS limit, or 0.0594 gr/dscf.

Scenario	Throughput		Current Emissions		Future NSPS		tpy reduced	ESP Annual Cost	$/ton
1a. Small LK, NSPS to 0.02	20,000	dscfm	0.0594	gr/dscf	0.02	gr/dscf	29.58	$581,551	$19,658
1b. Small LK, NSPS to 0.01	20,000	dscfm	0.0594	gr/dscf	0.01	gr/dscf	37.09	$581,551	$15,678
1c. Large LK, NSPS to 0.02	40,000	dscfm	0.0594	gr/dscf	0.02	gr/dscf	59.17	$905,559	$15,305
1d. Large LK, NSPS to 0.01	40,000	dscfm	0.0594	gr/dscf	0.01	gr/dscf	74.18	$905,559	$12,207

Scenario 2 (used by EPA): A facility performs a project that is considered a modification and triggers NSPS applicability for a lime kiln. The current lime kiln scrubber either cannot meet the current 0.064 gr/dscf limit, or it is in need of replacement, so the facility needs to install a new scrubber as part of the project. The impact of reducing the NSPS limit is the difference between the cost of the scrubber that will achieve compliance with 0.064 gr/dscf and the cost of the scrubber PLUS the cost of an ESP that will achieve compliance with a lower level like 0.01 gr/dscf. We have assumed that both the scrubber and the ESP are necessary because the scrubber controls TRS and SO_2 from the kiln and the ESP is needed to get additional PM control beyond what the scrubber can achieve. The incremental cost can be represented by the ESP annual cost.

AF&PA would like to point out that scenario 2 would be less likely to occur, as a facility would be more likely to upgrade newer equipment that already complies with the NSPS limit rather than older equipment that does not. However, we have included this scenario for completeness as EPA has evaluated this type of scenario.

Scenario	Throughput		Current NSPS		Future NSPS		tpy reduced	ESP Annual Cost	$/ton
2a. Small LK, NSPS to 0.02	20,000	dscfm	0.066	gr/dscf	0.02	gr/dscf	34.54	$581,551	$16,837
2b. Small LK, NSPS to 0.01	20,000	dscfm	0.066	gr/dscf	0.01	gr/dscf	42.05	$581,551	$13,831
2c. Large LK, NSPS to 0.02	40,000	dscfm	0.066	gr/dscf	0.02	gr/dscf	69.08	$905,559	$13,109
2d. Large LK, NSPS to 0.01	40,000	dscfm	0.066	gr/dscf	0.01	gr/dscf	84.10	$905,559	$10,768

Scenario 3. A facility performs a project that is considered a modification and triggers NSPS applicability for a lime kiln. The kiln is equipped with an ESP or an ESP/scrubber combination that complies with a 0.064 gr/dscf PM limit but would not meet a lower limit such as 0.02 or 0.01 gr/dscf. In the current case, the controls would not be replaced. In a future case where the NSPS limit was lowered, the ESP may have to be upgraded (if space is available for an upgrade). Therefore, the cost of lowering the NSPS is the cost the ESP upgrade. The table below presents example calculations of cost effectiveness for 2 sizes of kilns and 2 levels of NSPS revision. Based on a review of the ICR data provided by EPA, it appears that lime kilns equipped with ESPs have emission rates of 0.025 gr/dscf or less, so we have used that emission rate as the current emission level.

Scenario	Throughput		Current Emissions		Future NSPS		tpy PM reduced	ESP Annual Cost	$/ton
3a. Small LK, NSPS to 0.02	20,000	dscfm	0.025	gr/dscf	0.02	gr/dscf	3.75	$161,952	$43,138
3b. Small LK, NSPS to 0.01	20,000	dscfm	0.025	gr/dscf	0.01	gr/dscf	11.26	$161,952	$14,379
3c. Large LK, NSPS to 0.02	40,000	dscfm	0.025	gr/dscf	0.02	gr/dscf	7.51	$253,828	$33,805
3d. Large LK, NSPS to 0.01	40,000	dscfm	0.025	gr/dscf	0.01	gr/dscf	22.53	$253,828	$11,268

Scenario 4. A facility installs a new lime kiln to replace an existing lime kiln. The facility also triggers new source MACT so changing the NSPS limit to the new source MACT level does not have any associated cost.

Summary

Under all scenarios, the cost of lowering the NSPS PM limit for modified units is very high, and none of the examples evaluated show that additional control is cost effective. An examination of the ICR summary data provided by EPA to AF&PA indicates that lime kilns equipped only with scrubbers are not likely to meet an NSPS limit of 0.02 gr/dscf or less, but may meet 0.066 gr/dscf. Therefore, if most units can meet the current NSPS limit, Scenario 1 is much more likely to occur than Scenario 2.

EPA has estimated that 2 lime kilns will be modified over the next 10 years. The following table shows example total cost and total cost effectiveness evaluations, depending on which subsets of the 3 Scenarios are selected.

Cost Scenario	annual cost	tons reduced	$/ton
1 under scenario 1d	$905,559	74.18	$12,207
1 under scenario 2d	$905,559	84.10	$10,768
Total	$1,811,118	158.3	$11,442
Cost Scenario	**annual cost**	**tons reduced**	**$/ton**
1 under scenario 1b	$581,551	37.09	$15,678
1 under scenario 2b	$581,551	42.05	$13,831
Total	$1,163,102	79.1	$14,697
Cost Scenario	**annual cost**	**tons reduced**	**$/ton**
1 under scenario 2b	$581,551	42.05	$13,831
1 under scenario 3d	$253,828	22.53	$11,268
Total	$835,379	64.6	$12,937

C. Summary

The following table shows the ranges of cost estimates AF&PA developed under the various scenarios evaluated for smelt tanks and lime kilns.

Total Cost	Estimated Number Modified	Min total annual cost	Max total annual cost	Min total capital cost	Max total capital cost	Min $/ton	Max $/ton
Lime Kilns	2	$1,163,102	$1,811,118	$1,886,972	$8,664,456	$10,768	$19,658
Smelt Tanks	6	$121,222	$2,634,300	$16,495,143	$23,992,982	$1,158	$59,708

VIII. Additional Comments

A. The New Requirement for Electronic Reporting Is Burdensome and Unnecessary

EPA has included a new reporting requirement in proposed Subpart BBa that will be excessively burdensome to industry. This requirement is not justified. Proposed 60.288a(b) and (c) state that within 60 days of completing each performance test and CEMS performance evaluation test, the owner/operator must submit the test data to the EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) when the data and methods are compatible with the ERT.

Facilities are required to submit performance test data to regulatory agencies and provide certifications on their semi-annual compliance reports that they have performed the required monitoring and will provide information on any deviations from the testing requirements. Additional performance test report submittals to EPA provide no useful purpose, environmental or otherwise, and are an additional administrative burden on operating facilities. The ERT continues to be revised and updated due to various flaws. It is unreasonable to put sources at risk of violations (late reporting) because of EPA reporting tool issues or availability. (For example, the CDX system went down on July 1, 2013, the due date for TRI reports and many facilities were unable to submit reports electronically until July 2.)

A number of states already specify that performance test results be submitted in an electronic format. EPA should remove its reporting format requirement from the rule and work more closely with states to develop a universal reporting system that is not costly or redundant, does not require different electronic reporting formats, and that is not problematic and labor-intensive for data entry. As proposed, the rule's requirement is an extra, excessive burden for mills and stack testing vendors. EPA needs to defer any electronic collection of data until the CDX system is fully functional, user-friendly, and streamlined with States.

IX. Conclusion

AF&PA appreciates the opportunity to submit these comments on the proposed revisions to the Kraft Pulp Mills NSPS. We agree with the proposed changes to the PM limits and with EPA's conclusions that no advances in controls have occurred and no other sources or pollutants should be regulated under Subpart BBa. However, some of EPA's proposed changes are not in line with the conclusion that control technologies have not changed since the last review of the standard. It is not feasible for sources to meet all of the standards at all times. Considerations need to be made for additional startup and shutdown scenarios and for safety venting.

AF&PA stands ready to assist as EPA continues its work on this rule. If you have any questions about these comments or need additional information, please do not hesitate to contact Tim Hunt at 202-463-2588.

Attachment A

NCASI Comments on Proposed New Source Performance Standards for Kraft Pulp Mills ((78 Fed. Reg. 31316, May 23, 2013), July 23, 2013

ncasi

NATIONAL COUNCIL FOR AIR AND STREAM IMPROVEMENT, INC.
SOUTHERN REGIONAL CENTER
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July 23, 2013

EPA Docket Center (EPA/DC)
Environmental Protection Agency
Mailcode 2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460

RE: Docket ID No. EPA–HQ–OAR–2012-0640, Kraft Pulp Mills NSPS Review (78 Federal Register 31316, May 23, 2013)

Dear Sir/Madam:

The National Council for Air and Stream Improvement (NCASI) greatly appreciates the opportunity to submit comments on the proposed revisions to the Kraft Pulp Mills NSPS (78 Fed. Reg. 31316, May 23, 2013). NCASI is a research organization engaged in conducting research on environmental topics relevant to the forest products industry. Over its 70-year history, NCASI has conducted studies in a variety of areas including air emissions, and worked extensively in developing emissions data used in historical Maximum Achievable Control Technology (MACT) rulemakings affecting this industry. NCASI also assisted EPA with review and input during the development of the 2011 Pulp and Paper Information Collection Request (ICR), sections of which were reviewed by EPA as part of this proposed rulemaking. We draw from our experience and long history of involvement in these areas, in providing these comments on EPA's proposed revisions to the Kraft Pulp Mills NSPS.

NCASI has carried out a targeted review of data in the 2011 Pulp and Paper ICR, with focus on NSPS sources, in order to (a) develop a better understanding of data quality, (b) ascertain whether the data sufficiently represented operations during periods of *startup* and *shutdown*, and (c) comment on data quality analyses relevant to this rulemaking proposal. Given the extensive volume and nature of performance data in the ICR, and the relatively short comment period, this review did not encompass the entire dataset. Our comments on EPA's data analysis pertain to issues that have broad applicability and therefore the potential to significantly impact the conclusions.

In addition to the above, NCASI is also providing comments on EPA's proposal to require initial and repeat performance testing of condensable particulate matter (CPM). Preliminary studies conducted by NCASI using the new EPA Method 202 (promulgated in Dec 2010) indicate unresolved method artifact and bias issues. NCASI is currently engaged in technical studies to

better quantify these biases and identify solutions. Given our understanding of CPM measurement method issues, it is our assessment that the CPM testing requirement may be premature as it may further contribute to the uncertainty relating to CPM emissions.

We would like to thank you for the opportunity to comment on this proposal and your consideration of the issues included in these comments. Please feel free to contact me at (352) 244-0965 or vvarma@ncasi.org if you have questions or need more information.

Sincerely,

Vipin K. Varma, PhD
Vice President – Air Quality

NCASI Comments on proposed revisions to the Kraft Pulp Mills NSPS (78 FR 31316, May 23, 2013).

NCASI has specific technical comments on the revisions to the Kraft Pulp Mill New Source Performance Standards (NSPS) proposed on May 23, 2013. These comments relate to EPA's analysis of COMS/CEMS performance data in the 2011 Pulp and Paper Information Collection Request (ICR) and miscellaneous data quality issues. Additionally, NCASI is also commenting on the proposed requirement to conduct initial and repeat performance testing of condensable particulate matter (CPM), in light of recent findings related to method artifacts and biases.

1. EPA's analysis of ICR data does not sufficiently support the conclusion that the proposed opacity/TRS limits and monitoring allowances are "adequately demonstrated"

EPA's conclusions, on the ability of new/modified/reconstructed NSPS recovery furnaces and lime kilns to comply with the proposed limits and monitoring allowances, are based on a review of COMS and TRS CEMS data in the 2011 Pulp and Paper ICR. NCASI has examined the conclusions from this analysis[1] and has carried out a targeted review of ICR data from NSPS furnaces and lime kilns in order to identify data quality issues.

a. EPA's analysis of source performance over an *annual* operating period does not sufficiently support the conclusion that compliance with the proposed monitoring allowances is "adequately demonstrated" on a *quarterly* basis

EPA is proposing to lower the opacity limits for recovery furnaces from 35% to 20% and add a 20% opacity limit for lime kilns. Concurrently, EPA is also proposing to lower the opacity monitoring allowance for recovery furnaces from 6% to 2% and add an opacity monitoring allowance of 1% for lime kilns. EPA has retained the 1% TRS monitoring allowance but placed upper limit restrictions (caps) of 30 ppm and 22 ppm, respectively, for recovery furnaces and lime kilns. EPA proposes that compliance with the monitoring allowances be calculated over a ***quarterly*** reporting period[2] and requests comments on this requirement, specifically, on whether a semiannual calculation basis would be more appropriate.

In general, EPA evaluated the performance of recovery furnaces and lime kilns against the proposed TRS and Opacity monitoring allowances by examining the performance data on an ***annual*** basis. EPA did not evaluate whether compliance with the proposed monitoring allowances have been "adequately demonstrated" under the currently proposed ***quarterly*** reporting basis or the alternative ***semi-annual*** reporting basis. Understandably, achieving

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[1] US EPA, *Review of the Continuous Emission Monitoring and Continuous Opacity Monitoring Data from the Pulp and Paper Information Collection Request Responses Pertaining to Subpart BB Sources*. April 5, 2013. (Docket Document ID: EPA-HQ-OAR-2012-0640-0039).

[2] Percent of the total number of possible periods of excess emissions in a quarter

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compliance on an annual basis is not equivalent to achieving compliance on a quarterly or a semi-annual basis.

A 1% ***annual*** monitoring allowance of the 730 TRS reporting periods in a year corresponds to a maximum of seven (7) reporting periods of excess emissions without triggering a violation of the standard (provided the applicable proposed cap is not exceeded). When considered on a ***quarterly*** or ***semi-annual*** basis, this corresponds to 1.8 (rounded up to 2) reporting periods per quarter or 3.6 (rounded up to 4) reporting periods semi-annually. A facility with seven (7) or fewer reporting periods in a year would therefore be in compliance on an ***annual*** basis. However, if more than two (2) excursions occur in any given quarter, or more than four (4) occur in a semi-annual period, the facility would fail to meet the requirement on either a quarterly or a semi-annual basis. EPA therefore cannot conclude, based on a review of ***annual*** performance data, that compliance with the proposed quarterly-based standards has been adequately demonstrated.

Two specific examples are provided below. In one example, the annual average TRS from a current NSPS recovery furnace [NDCE-WBESP] is reported as 0.75 ppm @ 8% O_2 (99th percentile = 2.55 ppm @ 8% O_2) for the year 2009. In the same year, five exceedances of the 5 ppmdv limit were reported. Data was available from 694 of 730 possible 12-hour averaging periods. On an annual basis, it would appear that the data from this NSPS recovery furnace demonstrate that the proposed standards are achievable. However, even though the annual percentage of averaging periods that exceeded 5 ppmdv was less than 1% (5/694 = 0.72%), 4 of the 5 exceedances occurred in the third quarter and the fifth exceedance occurred in the following quarter. If the proposed standards were applicable to this NSPS unit, the 1% monitoring allowance would be exceeded on a quarterly basis, and also on a semi-annual basis.

Another NSPS recovery furnace [NDCE-DBESP] in the dataset has an annual average TRS of 0.30 ppm @ 8% O_2 and a 99th percentile of 4.44 ppm @ 8% O_2. Six exceedances of the 5 ppmdv emission limit were reported (all during periods of startup or shutdown) with data available for 726 reporting periods. The percentage of averaging periods exceeding 5 ppmdv was calculated on an annual basis to be less than 1% (6/726 = 0.83%). However, all 6 exceedances occurred on four consecutive days in one quarter while trying to bring the recovery furnace back online. During this period, BLS was fired at a reduced rate along with supplementary fossil fuel firing. As indicated in Table 1, 3.3% (6/180) of averaging periods in the third quarter (3Q) exceeded 5 ppmdv. This example also indicates that the 1% monitoring allowance is not adequate when periods of startup and shutdown are included. Hourly production and 12-hour TRS data for this unit are plotted in Figure 1.

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Table 1. Comparison of Quarterly vs. Annual Evaluation of TRS CEMS Data for NSPS Recovery Furnace [NDCE-DBESP].

	1Q	2Q	3Q	4Q	Annually
No. of times exceeded 5 ppm @8% O_2:	0	0	6	0	6
No. of times exceeded 30 ppm @8% O_2:	0	0	1	0	1
Maximum 12-hour TRS average:	2.7	2.4	30.5	3.3	30.5
Averaging periods per quarter (or year):	180	182	184	184	730
No. of averaging periods w/ numeric data:	180	182	180	184	726
% of averaging periods >5 ppmdv @8% O_2:	0%	0%	3.3%	0%	**0.83%**

Examples of recovery furnaces reported to be meeting the proposed 20% opacity limit and 2% monitoring allowance on an annual basis, but unable to meet the requirements on a quarterly basis, were also identified in EPA's data analysis. Table 2 compares the ***quarterly*** and ***annual*** evaluation of exceedances for an NSPS NDCE-DBESP recovery furnace, reported to have an annual average opacity of 13.07% excluding exceedances. Table 3 provides the same comparison for another NSPS NDCE-DBESP recovery furnace reported to have an annual average opacity of 5.71% excluding exceedances.

Table 2. Comparison of Quarterly vs. Annual Evaluation of Opacity COMS Data for NSPS Recovery Furnace [NDCE-DBESP].

	1Q	**2Q**	**3Q**	**4Q**	**Annually**
No. of times exceeded 20% Opacity:	476	371	84	170	1101
Averaging periods:	21600	21840	22080	22080	87600
No. of averaging periods w/ numeric data:	21266	18505	21817	21338	82926
% of averaging periods >20% Opacity:	2.24%	2.00%	0.39%	0.80%	**1.33%**

Table 3. Comparison of Quarterly vs. Annual Evaluation of Opacity COMS Data for NSPS Recovery Furnace [NDCE-DBESP].

	1Q	**2Q**	**3Q**	**4Q**	**Annually**
No. of times exceeded 20% Opacity:	160	234	503	251	1148
Averaging periods:	21600	21840	22080	22080	87600
No. of averaging periods w/ numeric data:	21598	21840	22077	22060	87575
% of averaging periods >20% Opacity:	0.74%	1.07%	2.28%	1.14%	**1.31%**

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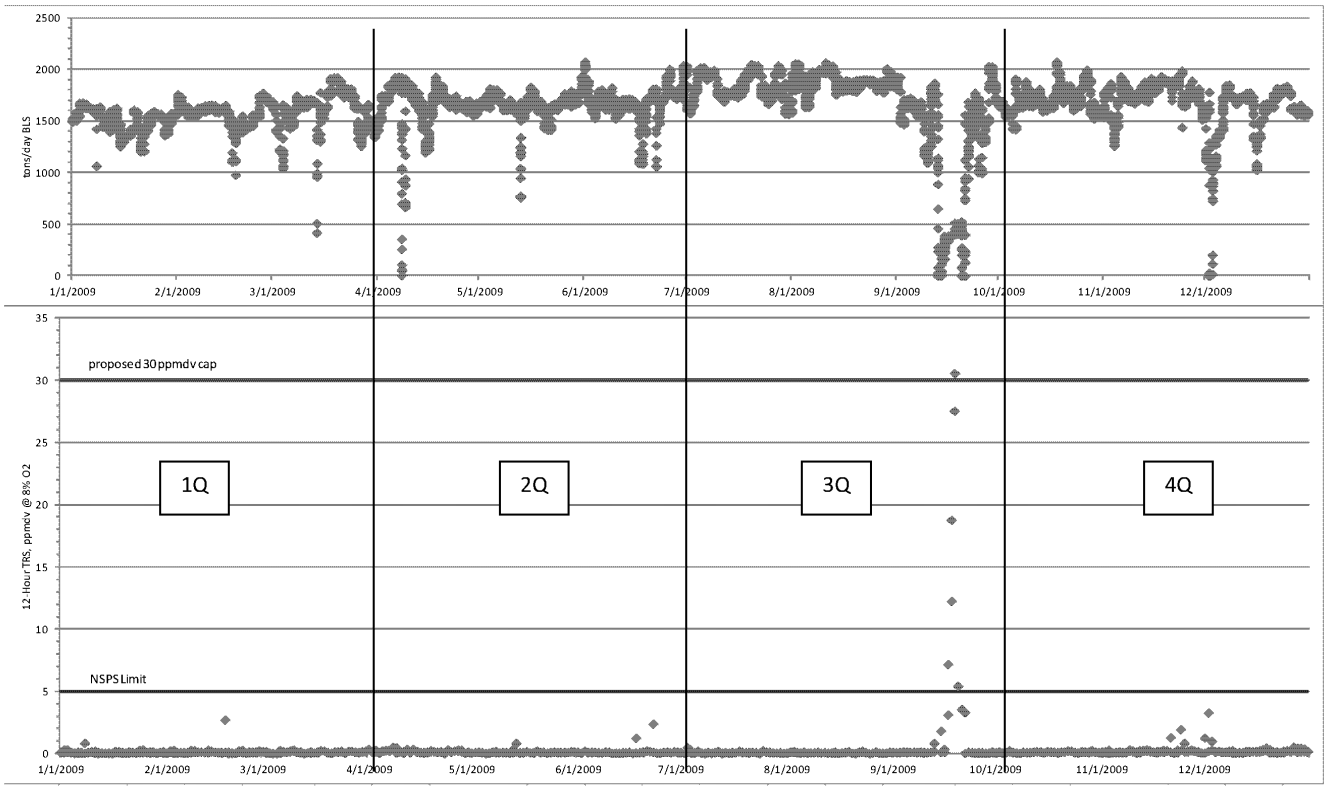

Figure 1. Hourly Production and 12-Hour TRS Data for NSPS Recovery Furnace [NDCE-DBESP] for the Four Calendar Reporting Quarters of 2009.

b. <u>EPA needs to adequately consider performance data under startup and shutdown conditions before proposing more stringent monitoring allowances that include startup and shutdown periods</u>

The targeted NCASI review of ICR data has identified instances where startup and shutdown (S/S) data were either excluded from data submittals or inappropriately labeled/included. In addition to the aspect identified above, this has the potential to further influence EPA's conclusions on the ability of NSPS units to comply with the proposed monitoring allowances, when also including startup and shutdown periods. Illustrative examples are provided below.

<u>Lime Kiln TRS – inappropriate S/S data</u>

EPA indicated in its CEMS review that 29 NSPS lime kilns were achieving the proposed 1% monitoring allowance on an annual basis. These datasets were examined by NCASI to assess the relevance of startup and shutdown data. ***Thirteen of the 29 lime kilns did not include any startup or shutdown data. A mixture of blank cells and values were included for four additional kilns during periods of startup and shutdown***.

Two additional mills included comments that they are required to maintain records of startup, shutdown and/or malfunction only when an emission standard is exceeded. The 2011 ICR requested archived data from 2009. In the absence of an applicable 1-hour emission standard, SSM data were not identified in the archive.

In cases where shutdown data was included and identified in a data set, it was sometimes reported as 'zero' and corresponded to periods of 'zero' production. The excerpted example in Table 5 below shows performance data for an NSPS lime kiln, equipped with an ESP followed by a wet scrubber. The annual average TRS for this unit was reported as 0.78 ppmdv @ 10% O_2 (99th percentile = 3.18). ***Fifty out of the 730 averaging periods*** were reported to contain startup or shutdown data, but ***forty seven out of these 50 periods were associated with zero production.*** The most common value reported for TRS during periods of startup or shutdown was 0.00 ppmdv. This value was reported 29 times and was in all cases associated with zero production and shutdown. The inclusion of 'zeros' as performance data artificially overstates unit performance, potentially impacting the results and conclusions.

ED_000419-0004117

Table 4. Illustrative example – (a) 'zeroes' as performance data and (b) data corresponding to zero production (shutdown) periods

12-hour period	CEMS Date (mm/dd/yyyy)	Average Production Rate (value)	Average Production Rate (units)	12-hour average TRS (ppmdv corrected for %O2)	%O2 correction (by volume, dry basis)	Was this data average affected by a condition of startup, shutdown, or malfunction?
256	5/8/2009	0.00	Ton CaO/hr	0.00	10	Shutdown
257	5/9/2009	0.00	Ton CaO/hr	0.00	10	Shutdown
258	5/9/2009	0.00	Ton CaO/hr	0.00	10	Shutdown
259	5/10/2009	0.00	Ton CaO/hr	0.00	10	Shutdown
260	5/10/2009	0.00	Ton CaO/hr	0.00	10	Shutdown
261	5/11/2009	0.00	Ton CaO/hr	0.00	10	Shutdown
262	5/11/2009	0.00	Ton CaO/hr	0.00	10	Shutdown
263	5/12/2009	0.00	Ton CaO/hr	0.00	10	Shutdown
264	5/12/2009	0.00	Ton CaO/hr	0.74	10	Shutdown
265	5/13/2009	0.00	Ton CaO/hr	1.94	10	Shutdown
266	5/13/2009	0.00	Ton CaO/hr	0.47	10	Shutdown
267	5/14/2009	11.21	Ton CaO/hr	0.12	10	Start-up

Firing of Fossil Fuels during Periods of Startup and Shutdown

Data on recovery furnace TRS performance sometimes also includes periods when black liquor solids (BLS) were not being fired. EPA has defined excess emissions as "all 12-hour averages of TRS concentrations above 5 ppm by volume at 8% O2 for straight kraft recovery furnaces during times when BLS is fired" [§60.284a (e)(3) at *FR 78* (100) 31338]. It is therefore inappropriate to include periods of oil (or other fossil fuel) firing during periods of startup and shutdown in the analyses.

The example in Table 5 below shows excerpted data from EPA's analysis for a recovery furnace [NDCE-DBESP] that triggered NSPS when it was modified in 2010. The maximum TRS block value reported for this unit was 6.13 ppmdv @ 8% O_2 and was identified as occurring during startup on oil. As noted in the data set, oil was also fired while shutting down.

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Table 5. Illustrative example indicating inclusion of periods with oil firing as startup/shutdown data

12-hour period	CEMS Date (mm/dd/yyyy)	Average Production Rate (value)	Average Production Rate (units)	12-hour average TRS (ppmdv corrected for %O2)	$\%O_2$ correction (by volume, dry basis)	Was this data average affected by a condition of startup, shutdown, or malfunction?
102	2/21/2009	0	kpph black liquor	1.18	8	Boiler starting up, oil firing
103	2/21/2009	0	kpph black liquor	1.00	8	Boiler starting up, oil firing
104	2/22/2009	85	kpph black liquor	6.13	8	Boiler starting up, oil firing
105	2/22/2009	250	kpph black liquor	3.02	8	
			kpph black liquor			
563	10/9/2009	280	kpph black liquor	0.02	8	
564	10/10/2009	280	kpph black liquor	0.12	8	Boiler shutting down for annual maintenance, oil firing
565	10/10/2009	132	kpph black liquor	0.04	8	Boiler shutting down for annual maintenance, oil firing
		0	kpph black liquor			
582	10/19/2009	0	kpph black liquor	0.72	8	Boiler starting up, oil firing
583	10/19/2009	0	kpph black liquor	0.01	8	Boiler starting up, oil firing
584	10/20/2009	0	kpph black liquor	0.00	8	Boiler starting up, oil firing
585	10/20/2009	72	kpph black liquor	0.01	8	Boiler starting up, oil firing
586	10/21/2009	241	kpph black liquor	0.06	8	
587	10/21/2009	187	kpph black liquor	0.71	8	Reduced BLS firing, add oil firing, low BLS inventory due to evaporator problems
588	10/22/2009	70	kpph black liquor	0.32	8	Reduced BLS firing, add oil firing, low BLS inventory due to evaporator problems
589	10/22/2009	212	kpph black liquor	0.42	8	
590	10/23/2009	262	kpph black liquor	0.78	8	
591	10/23/2009	255	kpph black liquor	0.93	8	

Unfortunately, ICR respondents were not instructed to identify whether other fuels were fired during startup or shutdown, and so the majority of respondents did not supply this information.

It is possible that the data quality issues identified above also extend to other datasets with startup and shutdown data. This has the potential to significantly impact the conclusions related to performance during these periods.

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c. **Given (a) the inconsistency in the basis (quarterly vs. annual) used for data analysis and (b) inadequate consideration of performance data related to startup and shutdown conditions, it is possible that compliance with the proposed monitoring allowances is not adequately demonstrated for recovery furnaces and lime kilns**

Citing another specific example that relates to opacity limits and monitoring allowances, EPA, in its review of COMS data from recovery furnaces, ascertained that only 12 out of 160 recovery furnaces were unable to meet the proposed 20% opacity limit and the 2% monitoring allowance. They subsequently concluded that compliance at these levels is adequately demonstrated. As discussed above, EPA's assessment of performance using ***annual*** performance data (as opposed to quarterly or semi-annual) may have influenced these conclusions. Additionally, 7 out of the 12 furnaces that were unable to meet the limits were subject to NSPS, indicating that achievability is an issue for NSPS units.

A thorough review of NSPS unit performance, carried out using the same averaging time as proposed in the standard, is necessary in order to support the "adequately demonstrated" conclusion. Additionally, the analysis needs to ensure that ***startup*** and ***shutdown*** periods are appropriately identified and adequately considered. Given the extensive scope and nature of available performance data, and the relatively short comment period, NCASI was unable to carry out this comprehensive assessment, especially to verify the inclusion and appropriate consideration of ***startup*** and ***shutdown*** periods.

2. **The NCASI review has identified other data quality issues with the potential to unduly influence the conclusions**

a. **Inclusion of "zero" COMS/CEMS values during process downtime periods**

Section I of the CEMS/COMS data review memorandum[3] describes the quality assurance/ quality control (QA/QC) procedures that were applied to the CEMS and COMS data. The memorandum states the following: "All data provided were reviewed for erroneous COMS or CEMS readings…….All negative readings were deemed suspect and were removed from the dataset to prevent artificial lowering of a unit's annual average performance." Additionally, it is stated that "***Abnormally large values*** that occurred during periods labeled as "process downtime" were removed if the production rate was reported as zero to indicate that the unit was non-operational… [in order] …to prevent the artificial increase in the annual average emissions associated with the unit." While this approach may prevent artificial inflation, it does not prevent the opposite, i.e., an artificial lowering of the averages. ***All data*** associated with zero production need to be removed from an analysis of unit performance, not just 'abnormally large' values. Inclusions of zeros during times of non-operation not only artificially lower

[3] U.S. EPA. *Review of the Continuous Emission Monitoring and Continuous Opacity Monitoring Data from the Pulp and Paper Information Collection Request Responses Pertaining to Subpart BB Sources.* April 5, 2013. (Docket Document ID: EPA-HQ-OAR-2012-0640-0039).

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calculated averages but also inflate the count of averaging periods containing numeric data (as in the case of the lime kiln example in Section 1b (Table 2). The count of averaging periods with numeric data appears in the denominator when the percentage of periods exceeding a proposed limit (20%, 8 ppmdv @ 10% O2, or 5 ppmdv @ 8% O2) is calculated. Thus, the inclusion of these values in the analyses results in artificially low "monitoring exceedance" percentage calculations as well.

b. <u>Inclusion of erroneous/inappropriate data in assessing unit performance</u>

NCASI has identified numerous instances where erroneous data were included in the ICR data analysis (negative values, values corresponding to "zero production", etc.). NCASI acknowledges that EPA was tasked with the analysis of a large quantity of fairly complex datasets in a short period of time. However, the lack of consistency in applying QA/QC procedures has the potential to significantly impact the conclusions from this data analysis, especially given the need to ascertain that performance is "adequately demonstrated" even when including startup and shutdown periods. It is therefore difficult to draw conclusions on this aspect when erroneous data have not been removed from analysis.

<u>As an example</u>, the maximum 6-minute average opacity for one of the industry's newest NSPS recovery furnace modifications [NDCE-DBESP-WPR] is reported as 39.52% and the annual average opacity excluding exceedances is reported as 4.20%. However, an examination of the underlying data reveals the following:

1) the maximum opacity identified in the analysis is a 60-minute rolling average and not a 6-minute average as indicated,
2) the reported 6-minute opacity averages are higher (as expected) than the 60-min averages,
3) the unit's calculated average performance (which should be evaluated on a quarterly basis, not an annual basis) was artificially lowered by the inclusion of 1199 negative values that were retained in the data set and the use of the 60-minute rolling average for the first 3 quarters of the year, and
4) 11,149 of the 6-minute averages associated with zero production (ranging from -2.06 to 23.25%) were retained in the data set.

<u>In another example</u>, the maximum 6-minute average opacity for another NSPS recovery furnace [NDCE-DBESP-WPR] is reported as 70% and is identified within the data et as the high span value associated with the quarterly filter audit. In fact, when the data from this unit are examined on a quarterly basis, the high value in each quarter is associated with the filter audit. It is not appropriate for monitor QC data to be treated as emissions values and be included in an assessment of unit performance.

Quality control checks of the continuous opacity monitoring system (COMS) appear in several datasets as brief-duration high spikes. A monitor calibration is performed daily and a filter audit is performed quarterly as part of QA/QC. The daily monitor calibration is visible in a

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COMS data set as a high spike occurring over two consecutive 6-minute averaging periods at approximately the same time each day. Unfortunately, the 2011 ICR provided no guidance on how to report and identify COMS quality control data. Consequently, these data were included in some cases and excluded in others, thus resulting in inconsistencies in the datasets and associated data analyses. If these data were not included in the data submissions, explanatory texts such as "Invalid Data" or "COMS cal" were placed in the corresponding worksheet cells in some cases. The cells were left blank in other cases. In such cases, QC data were not included in EPA's calculations since "blank" and "text" values are non-numeric. However if the calibration values were either reported, or as occurred in some cases, substituted with "0", these values were inappropriately included as emissions values.

Multiple instances of inclusion of erroneous/inappropriate data were found in NCASI's targeted review. The examples provided in these comments are by no means the only instances were these issues were identified. These data quality issues have the potential to influence the conclusions that performance with the proposed monitoring allowance has been "adequately demonstrated." A thorough review of NSPS unit performance that includes a consistent quality assurance of all data, including those related to startup/shutdown conditions, is essential in order to support the "adequately demonstrated" conclusion.

c. O_2 Correction of TRS CEMS Data Applied Multiple Times

In the CEMS/COMS data review memorandum[4], EPA reports that it was assumed that the data submitted in certain TRS CEMS datasheets were uncorrected because the $\%O_2$ correction data provided in the adjacent column of the spreadsheet(s) were not reported as 8% or 10%. NCASI has obtained confirmation from two facilities so far that O_2-corrected TRS data were provided as requested, and that the 12-hour O_2 averages used to correct the data to 8% or 10%, as appropriate, were reported in the $\%O_2$ correction column. Thus, TRS data for units 109.RB3, 109.RB4, 109.LK1, and 112.AA-110 have been erroneously double corrected for O_2 in EPA's analysis.

[4] U.S. EPA. *Review of the Continuous Emission Monitoring and Continuous Opacity Monitoring Data from the Pulp and Paper Information Collection Request Responses Pertaining to Subpart BB Sources*. April 5, 2013. (Docket Document ID: EPA-HQ-OAR-2012-0640-0039).

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3. **EPA's analysis of COMS data does not sufficiently support the decision to propose lowering the opacity limit and monitoring allowance for modified recovery furnaces**

EPA's COMS data analysis does not (a) distinguish between new/reconstructed and modified furnaces and (b) assess the performance of modified recovery furnaces using the proposed ***quarterly*** or ***semi-annual*** period. Therefore, it is unclear whether compliance with the proposed 20% opacity limit, at the 2% monitoring allowance level, is adequately demonstrated for modified NSPS recovery furnaces.

4. **The option to use uncorrected TRS Concentrations during periods when stack oxygen ≥ 15 percent needs to be expanded to include other potential operating scenarios**

NCASI is in agreement with EPA's rationale in allowing facilities to use uncorrected TRS concentrations during periods when stack oxygen values are ≥ 15 percent. These high stack oxygen periods are typically indicative of (a) startup and shutdown conditions or (b) transient changes in boiler/lime kiln loading that have not been reflected in air flows. The ability to use uncorrected TRS concentrations mitigates the use of an artificially inflated (and inappropriate) oxygen correction factor.

The applicability of this procedure is limited, as proposed, due to the stipulation that it can be used only during periods of startup and shutdown where uncorrected TRS concentrations are below ***applicable limits*** (5 ppm for recovery furnaces and 8 ppm for lime kilns). The following operating scenarios exist:

- Periods of startup and shutdown where uncorrected TRS concentrations are below the respective upper restriction levels (30 ppm and 22 ppm for recovery furnaces and lime kilns, respectively) and stack oxygen concentration is ≥15 percent.

- Limited normal operating periods where uncorrected TRS concentrations are below the respective upper restriction levels (30 ppm and 22 ppm for recovery furnaces and lime kilns, respectively) and stack oxygen concentration is ≥15 percent.

An example scenario illustrating item 1 above is identified below in Table 6. EPA concludes in the COMS/CEMs background document that brief spikes in recovery furnace TRS concentrations (> 5 ppm) occurred during startup/shutdown periods and that the proposed upper restriction of 30 ppm adequately encompasses these spikes, after addressing extreme-value outliers. Having acknowledged that spikes greater than 5 ppm do occur during startup and shutdown periods, it is only logical to also allow the use of uncorrected TRS concentrations for these instances (uncorrected values below upper restriction level AND stack oxygen > 15%).

The scenario identified in Item 2 above (normal operation) is also expected to occur, although in limited cases. Given that EPA is proposing a standard that includes all operating periods, including startup and shutdown, it is only logical that EPA allow the use of this approach for ***all***

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operating periods when the uncorrected 1-hr TRS concentration is below the applicable upper restriction level (cap) and stack oxygen ≥ 15%.

Table 6. Scenarios with high stack oxygen and uncorrected TRS > applicable "limit" but < applicable upper restriction level ("cap")

Hourly Production Rate (value)	Hourly Production Rate (units)	1-hour average emission value for TRS (ppmdv RAW)	% O_2 (ppmdv)	Was this data average affected by a condition of startup, shutdown, or malfunction? If yes, please specify.
10	K Lbs BLS/Hr	2.16	**17.62**	Shutdown
84	K Lbs BLS/Hr	2.32	**16.5**	Shutdown
38	K Lbs BLS/Hr	**29.32**	**19.91**	Shutdown
105	K Lbs BLS/Hr	bad data	**20.25**	Startup
69	K Lbs BLS/Hr	**18.5**	**20.68**	Startup

5. **The procedure for calculating the 12-hr block average TRS concentrations needs to be modified to incorporate (a) the ability to use uncorrected TRS concentrations for certain periods and (b) the need to demonstrate performance against applicable "upper restriction" levels**

The procedure to calculate the 12-hr corrected TRS concentrations may need to be modified to better accommodate the proposal. The currently proposed procedure in §60.284a (c)(1)(i) involves (a) calculating the 12-hr uncorrected TRS concentrations, (b) calculating the corresponding 12-hr oxygen concentrations, and (c) carrying out the oxygen correction on the 12-hr average. The approach proposed below would be more appropriate given the need to consider uncorrected TRS concentrations during periods when stack oxygen levels are ≥ 15 percent.

A suggested procedure for calculating the corrected 12-hr TRS concentrations is described below and involves the following steps:

1. Compute the 1-hr average of uncorrected TRS concentrations
2. Calculate the corresponding 1-hr average of stack oxygen concentrations
3. Skip to step 5 if the uncorrected 1-hr average TRS concentration is < the applicable TRS limit (or the cap, as proposed above) AND the 1-hr stack oxygen ≥ 15 percent
4. Carry-out the oxygen correction according to equation in §60.384a (c)(1)(iii), if the 1-hr stack oxygen in < 15% to obtain the corrected 1-hr TRS concentration. Skip to step 6.

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5. Use uncorrected 1-hr TRS concentration in calculating the 12-hr block average.
6. Repeat steps 1 through 5 for each hourly average in the 12-hr block
7. **Roll-up the hourly averages to calculate the 12-hr block average concentration used to demonstrate compliance**

Table 7. Suggested procedure to calculate 12-hr TRS concentrations

			Current Approach - Correcting 12-hr blocks			Proposed Approach - Correcting 1-hr blocks	
1-hour average emission value for TRS (ppmdv RAW)	**% O_2 (ppmdv)**	**Was this data average affected by a condition of startup, shutdown, or malfunction? If yes, please specify.**	**12-hour avg. TRS (ppmdv RAW)**	**12-hour avg. O_2 (%)**	**12-hour avg. corrected TRS (ppmdv @8% O2)**	**1-hour avg. corrected TRS (ppmdv @8% O2)**	**12-HR AVG**
1.10	20.43	Startup				1.10 [a]	
1.01	20.39	Startup				1.01[a]	
3.04	20.56	Startup				3.04[a]	
24.28	6.09	Startup				21.17	
21.73	4.38	Startup				17.00	
20.67	3.53					15.38	
20.66	3.54					15.38	
21.17	3.95					16.14	
16.97	4.7					13.53	
21.58	4.28					16.78	
21.68	4.36					16.94	
22.88	5.22		16.40	8.45	16.99	18.85	13.03

[a] uncorrected TRS concentrations used to calculate 12-hr avg. – startup / shutdown and oxygen > 15%

The procedure suggested above (illustrative example in Table 7) will be beneficial to streamline the calculations required to demonstrate compliance with the 12-hr block average TRS standard, while accommodating the need to comply with upper restriction levels and the need to use uncorrected TRS values in certain instances.

As discussed in the Section 4 (and Table 6), the use of uncorrected TRS values needs to be extended to include instances (such as S/S) when uncorrected TRS values are below applicable upper restriction levels ("caps") but above applicable limits. The procedure suggested here would also be applicable for those instances.

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6. **Further clarification on the treatment of TRS measurements above instrument span (30 ppmdv) would be beneficial**

The procedure for reporting and treatment of uncorrected TRS concentrations above the span value for the instrument (30 ppmdv) needs further clarification. One suggested approach would be as follows:

- Allow the use of uncorrected TRS measurements for readings up to 60 ppmdv (2 times instrument span) for calculating the 1-hr uncorrected averages
- For those measurements that exceed 60 ppmdv (2 x instrument span), require the use of 60 ppm in averaging calculations.

This approach minimizes the use of extreme-value data with high levels of measurement uncertainty.

7. **The initial and repeat performance testing of Condensable Particulate Matter (CPM) may not help address current data gaps, given the unresolved method artifact and bias issues associated with the new EPA Method 202. NCASI is involved in technical studies to better understand these measurement issues and identify solutions**

EPA is proposing under Subpart BBa to require initial and repeat CPM emissions testing in conjunction with filterable PM testing, citing the lack of CPM data and the need to develop a better understanding of CPM emissions from pulp and paper sources. Recent work carried out by NCASI has identified several unresolved issues with the new version of EPA Method 202, promulgated in December 2010. Significant findings from ongoing technical studies on CPM measurement and emissions are summarized here:

1. Method evaluation studies carried out by NCASI indicate that the new M202 yields an average train blank value of 5.7 mg. These train blanks were measured during seven replicate field and laboratory studies, carried out over a period of several years and involving multiple sampling personnel. EPA's field evaluation study also yielded an average train blank of 5.33 mg, with values ranging from 4.6 to 6.22 mg. However, the currently promulgated version of M202 however only allows a maximum blank correction of 2 mg. The resulting positive bias associated with subtracting only 2 mg (as opposed to ~ 6.0 mg) can be a significant component of the total CPM measured during tests on low-emitting sources. More details on the impact of train blanks are provided in the draft report titled "EVALUATION OF THE PERFORMANCE OF EPA METHODS 201A AND 202 ON A NATURAL GAS-FIRED PACKAGE BOILER," provided as Attachment 1 to these comments.

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2. NCASI studies on a low-emitting source (natural gas package boiler) using the new M202, where runs of longer duration were carried out, indicate the potential for positive bias due to the capture of SO_2 in the impingers and subsequent characterization of this SO_2 as SO_4 (and CPM) in the method. More details on this characterization study are provided in the draft report titled "EVALUATION OF THE PERFORMANCE OF EPA METHODS 201A AND 202 ON A NATURAL GAS-FIRED PACKAGE BOILER," provided as Attachment 1 to these comments. The positive biases resulting from (a) the use of an inappropriate blank correction and (b) the formation of method artifacts are also relevant for the sources covered by this rulemaking.

3. NCASI recently carried out ion characterization studies of concurrently collected filterable particulate (EPA Method 5 – front half) and CPM (new EPA Method 202 – back half) samples from a DCE recovery furnace. The primary cation captured in the CPM train was ammonium (NH_4^+) while the anions included sulfate, chloride, and carbonate. By comparison, the front half sample did not contain any NH_4^+, suggesting that the ammonium captured in the back-half cannot be attributed to a partial breakthrough of filterable particulate. The presence of sodium in the front-half catch, and its absence in the back-half catch, further confirms that there was no breakthrough of filterable particulate (sodium sulfate particulate is captured on the front-half filter). These results indicate the potential for positive bias in CPM measurements in the presence of free ammonia. Any free ammonia in stack gases would pass through the front-half filter, react with any acid gases to form ammonium sulfate or ammonium chloride, and be characterized as CPM during subsequent gravimetric measurements. The results from this study are summarized in Table 8.

Table 8. Components of kraft recovery furnace PM and CPM

	Mass Captured, mg	
Analyte	PM	CPM
Carbonate	0.89	22.98
Chloride	13.5	35.68
Nitrate	0.03	0.09
Sulfate	24.07	16.68
Ammonium	0.21	20.25
Sodium	17.82	0.57

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4. NCASI has also carried out characterization studies on the CPM catches from 3 DCE furnaces and 3 NDCE furnaces. Ammonium (NH_4^+) accounted for ~ 30% of the total CPM mass captured in 2 of the 3 DCE furnaces and 5 to 10% of the total CPM mass in the 3 NDCE furnaces.[5] Ammonium (NH_4^+) accounted for 15 to 25% of CPM mass collected during sampling on 6 lime kilns and from 10 to 35% of CPM mass in 3 smelt dissolving tanks.[4] These results indicate the potential for positive bias in CPM measurements due to free ammonia (a) is relevant for the sources covered in this rulemaking recovery furnaces and (b) merits a more thorough investigation.

NCASI is carrying out additional CPM method evaluation studies as part of the ongoing technical studies program, including (a) identifying the source and extent of SO_2 and other method artifact biases, (b) comparing the performance of M202 against other equivalent test methods, and (c) developing modifications to mitigate these issues. It is our assessment that EPA should therefore defer proposing the CPM testing requirement until more information on the unresolved method issues becomes available. Any CPM data generated in the interim will therefore be of questionable quality and will further contribute to the uncertainty surrounding CPM emissions.

[5] Unpublished results from NCASI study

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Summary

As discussed above, EPA's analysis of ***annual*** performance data does not sufficiently inform whether compliance with the proposed opacity/TRS monitoring allowances is adequately demonstrated on a ***quarterly*** basis. Our review also identified instances where startup and shutdown data were either excluded from the datasets or inappropriately labeled/included. These aspects of data analysis have broad applicability and therefore the potential to impact conclusions on achievability, especially when including periods of startup and shutdown.

Given (a) the inconsistency in the basis (quarterly vs. annual) used for data analysis and (b) the inadequate consideration of performance data related to startup and shutdown conditions, it is possible that compliance with the proposed monitoring allowances is not adequately demonstrated for recovery furnaces and lime kilns. We request EPA to take these factors into consideration before finalizing the proposed monitoring allowances that include periods of startup and shutdown.

Given the various artifact and bias issues discussed above, it is our assessment that the CPM testing requirement using EPA Method 202 is premature at this juncture. The new data may further contribute to the uncertainty regarding CPM emissions and may not help address current data gaps.

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EVALUATION OF THE PERFORMANCE OF EPA METHODS 201A AND 202 ON A NATURAL GAS-FIRED PACKAGE BOILER

DRAFT TECHNICAL BULLETIN

MAY 2013

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EVALUATION OF EPA METHODS 201A AND 202 ON A NATURAL GAS-FIRED PACKAGE BOILER

1.0 INTRODUCTION

The National Ambient Air Quality Standards (NAAQS) for particulate matter (PM) were originally established in 1970 and have been revised periodically thereafter. Fine particles of aerodynamic diameter less than or equal to 2.5µm ($PM_{2.5}$) are a concern for EPA due to their perceived human health effects. EPA has progressively lowered both the *annual* and *24-hour* NAAQS standards for $PM_{2.5}$, with the latest revision to the *annual* primary $PM_{2.5}$ standard, from 15µg/m^3 to 12µg/m^3, being promulgated in January 2013. States are developing implementation plans to reduce primary ambient $PM_{2.5}$ concentrations and addressing the emissions of $PM_{2.5}$ precursors like NO_x and SO_2 as part of their air quality permitting and regional haze reduction programs. In an effort to develop their fine particulate emission inventories, states are also increasingly requiring facilities to model $PM_{2.5}$ emissions from both point sources and fugitive/area sources (paper machines, chipping/debarking operations, etc.) as part of Title V permit modifications, renewals, or new applications.

Data used to model $PM_{2.5}$ emissions include source-specific test data, test data from similar sources, or default emission factors compiled by the EPA. The EPA database of emission factors, commonly referred to as AP-42 factors, is maintained through EPA's Office of Air Quality Planning and Standards (OAQPS). Each AP-42 emission factor is classified based on the quality of underlying data, with ratings ranging from A (excellent) through E (poor). For certain categories of sources, there are limited or no data available. In some cases, the emission test methodology behind the development of the factors was inappropriate. The AP-42 emission factors for PM emissions from natural gas combustion carry a quality rating of B for filterable PM, and a quality rating of D for condensible PM (CPM). Recent emission testing efforts on natural gas fired combustion sources indicate that the AP-42 PM emission factors for these types of sources are biased high by an order of magnitude or more for direct $PM_{2.5}$ emissions (sum of filterable PM and condensible PM).

This report documents the results of a study carried out on a natural gas fired package boiler to measure direct $PM_{2.5}$ emissions. EPA Methods 201A and 202 were used to measure filterable $PM_{2.5}$ and CPM, respectively. Long duration sampling runs (3, 24-hour tests) were carried out in an effort to lower the in-stack detection limits. Paired sampling trains were co-located near the center of the stack. The front-half of both sample trains consisted of the sample train components specified in EPA Method 201A. The back-half of the first sampling train included the components specified in the version of EPA Method 202 promulgated in December of 2010 (new Method 202) The back-half of the second sampling train included the components specified in the previous version of EPA Method 202 (old Method 202). Comparisons were made between the measured emission rates for filterable $PM_{2.5}$ and condensible PM when using these paired trains. The results are also compared against the corresponding AP-42 emission factors for PM from natural gas combustion.

2.0 METHOD DESCRIPTIONS

EPA Method 201A (US EPA 2010a) was used to measure filterable $PM_{2.5}$, emissions on both sample trains. EPA Method 202 as promulgated in 2010 (US EPA 2010b) was used to measure CPM emissions in one sampling train and EPA Method 202 as promulgated in 1991 (US EPA 1991) was used to measure CPM in the other sampling train.

2.1 Method 201A

EPA Method 201A is an isokinetic sampling method for determining emissions of filterable PM_{10} and $PM_{2.5}$. Classification of particulate matter into the PM_{10} and $PM_{2.5}$ size ranges is accomplished by use of two cyclones, followed by a high efficiency glass-fiber, quartz-fiber, or polymer filter. Filter

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capture efficiency is the same as specified for EPA Method 5, 99.95 percent capture efficiency for a 0.3 micron dioctyl phthalate particle. The two cyclones have cut points for particulate matter of 10 and 2.5 microns, which is based on the aerodynamic properties of the particulate matter. Both cyclones and filter are attached to the end of the sampling train probe, and are thus located in the flue gas stream during sampling. The filter is normally located in the stack between the cyclone(s) and the end of the sample probe, but can be located out of the stack in a heated oven. If it is desired to measure only filterable PM_{10}, or only filterable $PM_{2.5}$ emissions, a single cyclone followed by the filter assembly is used. When using both cyclones a sampling port with an internal diameter of six inches is required to accommodate the sample head. A sample head with a single cyclone and filter assembly can usually be accommodated in a sample port with an internal diameter of four inches. Figure 2.1 is a diagram of the Method 201A sampling train with the EPA Method 4 components used in the condenser section of the sampling train. EPA Method 4 is used to determine the moisture content of the flue gas sample.

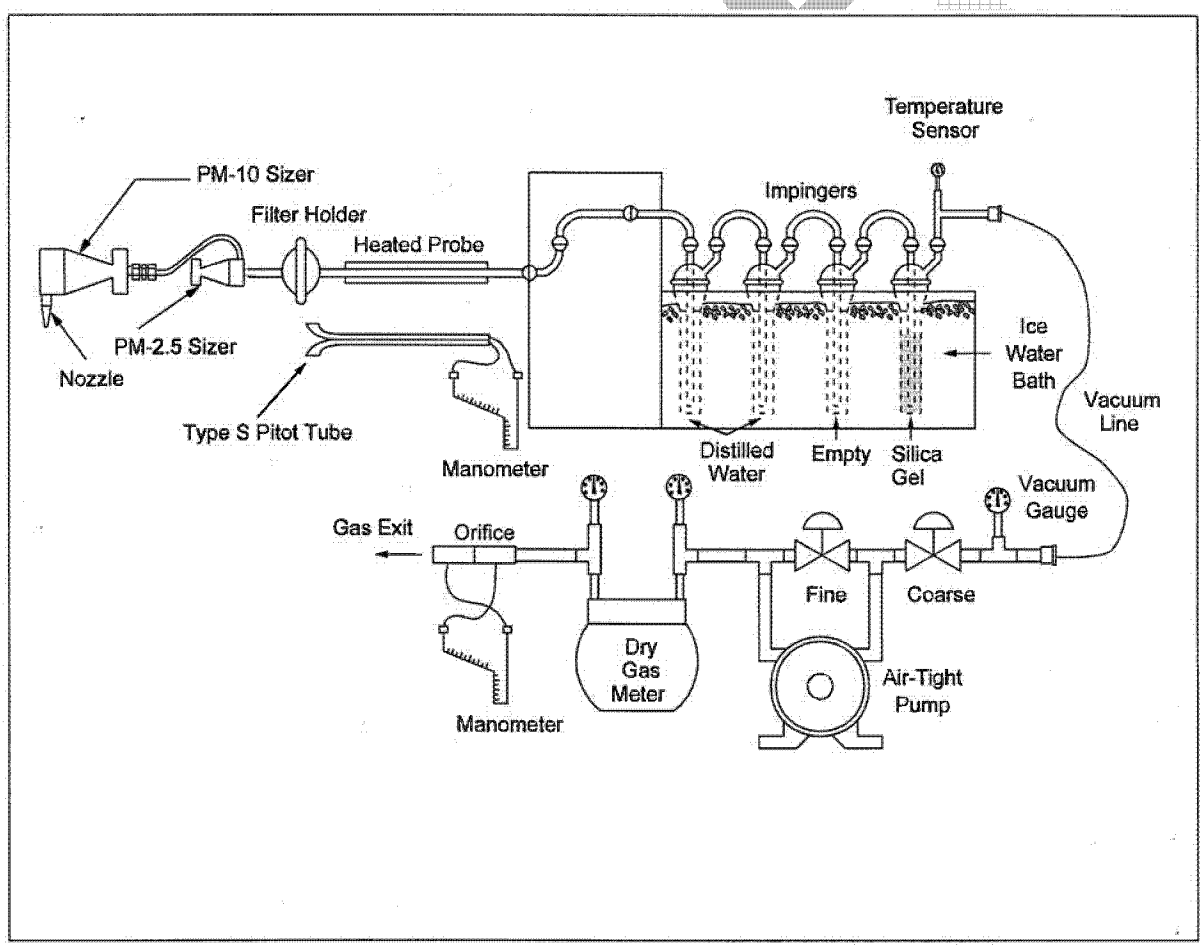

Figure 2.1 EPA Method 201A Sampling Train (Figure 1from EPA Method 201A, US EPA 2010a)

In this study, the Method 201A portion of the sampling trains were configured to measure filterable $PM_{2.5}$, thus only a single cyclone with a cut point of 2.5 microns and the in-stack filter were used for each sample train.

2.2 Old and New Method 202

EPA Method 202 is used to determine condensible PM emissions from stationary sources. The CPM emissions measured are dependent on the configuration of the front-half of the sampling train. Components in the flue gas that have a dew point that is higher than the filter temperature in the front-half of the sampling train will be captured on the filter and classified as filterable PM. Material in the flue gas which passes through the filter in the front-half of the sampling train and which condenses to form solid or liquid PM in the back-half of the sampling train is classified as CPM. Therefore, the temperature of the filter in the front-half of the train is the primary factor affecting what gets classified as being filterable PM, and what gets classified as CPM. High filter temperatures in the front-half of the sampling train will cause a greater portion of the direct PM emissions to be classified as CPM versus a low filter temperature.

As mentioned earlier, both the old and new versions of EPA Method 202 were used in this study. There are significant hardware, operational, and analytical differences between the old Method 202 and the new Method 202. The primary difference in hardware and operation of the sampling trains is that in the old Method 202 the flue gas is purposely bubbled through distilled, de-ionized water held in chilled impingers (see Figure 2.2), while in the new Method 202 contact between the flue gas and any moisture that is condensed from the flue gas is minimized. Minimization of contact in the new Method 202 is accomplished by the use of a water-jacketed condenser followed by a drop out container to capture the condensed moisture. This allows the flue gas to continue on through the sampling train without bubbling through the condensed water (see Figure 2.3). Minimizing the contact between the flue gas and the condensed moisture reduces the opportunity for absorption of SO_2 into water condensed from the flue gas. This in turn reduces the bias associated with the old Method 202 where SO_2 that is absorbed in the impinger solution can oxidize to form sulfates, thus imparting a positive bias in the estimated CPM emissions. The portion of the new Method 202 sampling train where the CPM is formed and captured is also operated at a higher temperature (65 to 85°F) than the ice-water bath of the old Method 202. The elevated temperature reduces the absorption efficiency of SO_2 in water, thereby further decreasing the potential for bias. Another operational difference between the old and new Method 202 relates to purging of the water sample. In the new Method 202, purging of the condensed water with pure nitrogen after the sample run is mandatory. Purging is performed to drive off any SO_2 that may have been absorbed in the condensed water, which is another means of reducing the opportunity for oxidation of SO_2 to sulfate. In the old Method 202 purging was optional, and when purging was performed the tester had the option of using ambient air for the purge or nitrogen, with nitrogen being more effective. For this study, the water captured in the condenser section of both trains was purged with pure nitrogen.

The old Method 202 has multiple options with regard to analysis of the CPM samples while the new Method 202 does not provide any options with regards to analysis of the samples. One of the options in the old Method 202 with respect to processing the water (inorganic) samples addresses the procedure used to dry the water samples. The old Method 202 allows the analyst to take the water samples to dryness at an elevated temperature (105 °C) in an oven or on a hotplate. This is in contrast to the new Method 202 where the analyst is directed to reduce the volumes of the water samples at an elevated temperature (105 °C) to not less than 10 ml. The analyst is to then continue drying the water samples at ambient temperature (not higher than 85°F) and pressure. The purpose of the drying procedure in the new Method 202 is to preserve, as part of the CPM sample, ammonium salts and similar compounds that can be volatilized at elevated temperatures. This can have unexpected consequences when comparing results from the old and new Method 202. While CPM emissions estimated using the new Method 202 are typically lower than CPM emissions estimated using the old Method 202, it is possible to have higher CPM emission estimates using the new method. If ammonia and hydrochloric acid, or other compounds that produce semi-volatile solids are present in

the source, the measured CPM emissions using the new Method 202 can be higher than when measured using the old Method 202. On sources of this nature, higher CPM emission estimates using the new Method 202 are the result of the differences in sample drying technique between the old and new methods.

Another option in the old Method 202 is the allowance for the use of an ambient temperature filter (CPM filter) between the second and third impingers. This option is provided to increase the capture efficiency of the sampling train, and was suggested for oil fired sources. The CPM filter option was used for this study to make comparison of results between the old and new Method 202 easier.

The multiple options in the old Method 202 with respect to hardware, operation of the sampling train, and sample analysis make it impossible to compare CPM emissions between different sources unless it is known that the method was performed with the same options on both sources. The new Method 202 is very prescriptive, making comparison of CPM emission estimates between sources possible. A significant portion of the variability seen, in the old Method 202 CPM emissions data, can be attributed to the availability of the various options in this method.

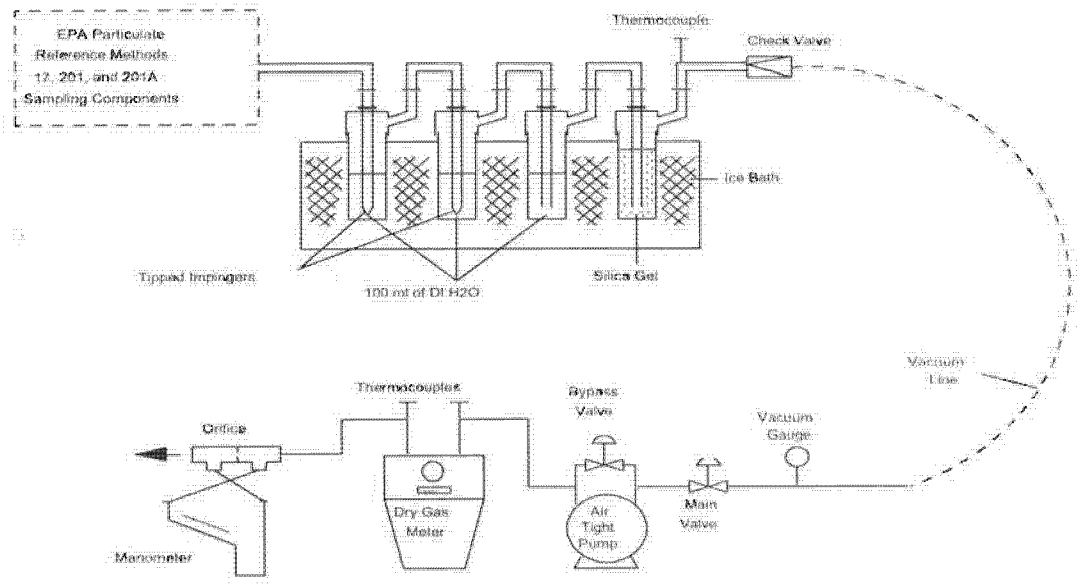

Figure 2.2 Method 202 Condenser Section (Figure 202-1from EPA Method 202, US EPA 1991)

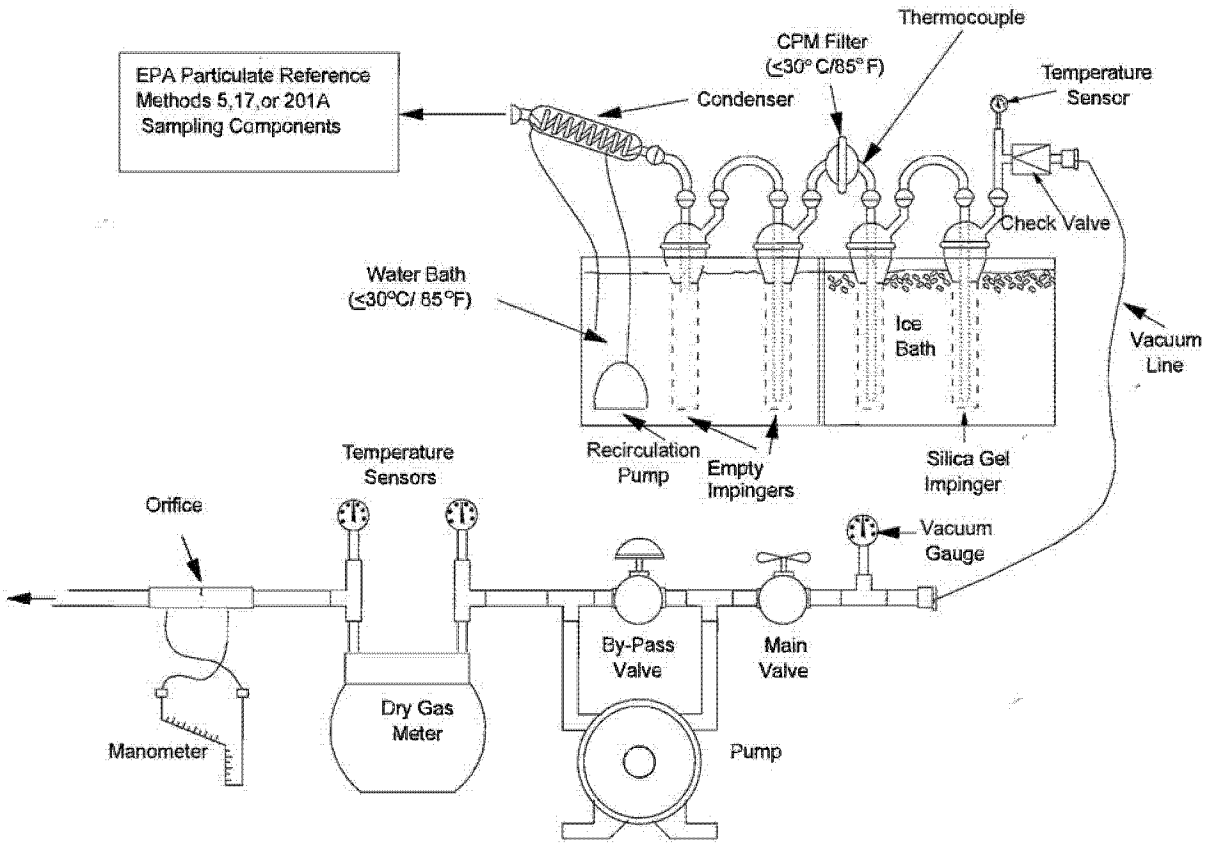

Figure 2.3 Method 202 Condenser Section (Figure 1from Method 202, US EPA 2010b)

3.0 TEST PROGRAM DESCRIPTION

Paired EPA Method 201A/202 sampling trains were used to measure direct $PM_{2.5}$ emissions from a gas fired package boiler. The sampling was single point isokinetic, with both sampling train inlet nozzles located in close proximity to one another near the center of the stack.

Cyclones and in-stack filter holders were constructed of stainless steel and manufactured by Andersen Instruments. Quartz fiber filters manufactured by Pall Life Sciences (Part No. 7197) were used for the in-stack filters in this study. Heated, glass-lined sampling probes were used, and cyclone and filter bypass glassware was used to conduct flue gases from the exit of the sampling probe, through the Method 5 filter oven, to the inlet of the Method 202 condenser. All components in the condenser section of the paired trains were constructed of borosilicate glass, with the exception of the filter support for the CPM filter, which was constructed from Teflon. PTFE membrane filters manufactured by Tisch Scientific (Part No. SF16015) were used as the CPM filter in both the new and old Method 202 sample trains for this study. A train blank was collected from each train by assembling the sampling trains, performing a leak check of the sampling trains, and collecting samples from the sampling trains in the same manner as was done for the actual test runs. The drop out for the new Method 202 sample train was charged with de-ionized water prior to assembly and leak check of the field blank sampling train. Both Method 202 trains were purged with pure, filtered nitrogen per the procedures specified in Section 8.5.3 of EPA Method 202.

During testing, the source was fired with natural gas and operated at approximately 71 percent of the source's steaming capacity. Operation of the source was steady-state during testing, with average flue gas oxygen content at 2.3 percent (dry-basis). Three 24-hour sample runs were performed with both trains operating simultaneously. Average flue gas sample volume collected was 434 dscf (12.3 dscm).

3.1 Modification of Method 201A Sampling Train

The measurement of direct $PM_{2.5}$ emissions on this source, fitted with four-inch diameter (I.D.) sampling ports, required a modification of the cyclone sampling head. The modified sampling head used only the cyclone with the 2.5 micron cut point and the in-stack filter. The equipment manufacturer's adapter plate for the $PM_{2.5}$ cyclone attaches the inlet nozzle directly to the side of the $PM_{2.5}$ cyclone, which required a six-inch sampling port, so an EPA Method 5 button hook nozzle was attached to the end of the $PM_{2.5}$ cyclone inlet tube. This put the nozzle inlet closer to the central axis of the sampling head and allowed introduction of the sampling head into a four-inch diameter port. Using the Method 5 nozzle also moved the inlet away from the body of the cyclone, and therefore reduced the opportunity for aerodynamic interference from the cyclone body with both sample collection and flue gas velocity measurements. Since the Method 5 nozzle was anticipated to have a lower cut point than the turnaround cup in the PM_{10} cyclone (Cyclone I), no significant loss of filterable $PM_{2.5}$ sample was anticipated. Figures 3.1 and 3.2 illustrate the modified Method 201A sampling head used in this study.

Figure 3.1 Modified Method 201A Sampling Head

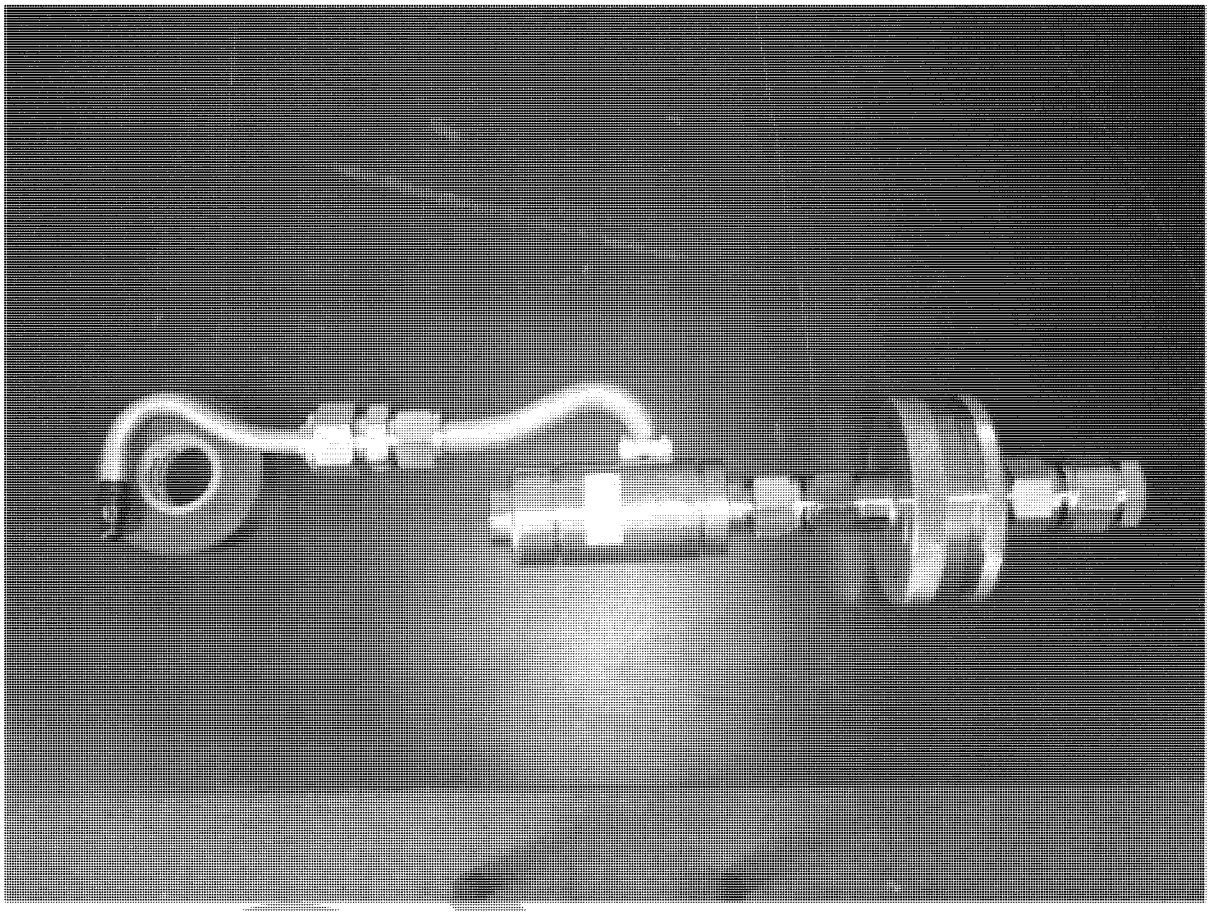

Figure 3.2 Modified Method 201A Sampling Head

In order to demonstrate that the modified Method 201A sampling head yielded filterable $PM_{2.5}$ results equivalent to the non-modified head, simultaneous sampling was performed on a DCE recovery furnace. One train was operated with the standard head as described in Method 201A, using both cyclones, and the other train was operated with the modified head as described above. The source tested had a vertically oriented, circular cross section stack with four sampling ports. Individual ports were 90 degrees from each adjacent port. During the simultaneous sampling, the probes from the two trains were inserted into ports that were opposite one another. Sampling was single-point isokinetic, at a location near the center of the stack. The inlet nozzles from the two heads were positioned within six centimeters from one another, but not closer than four centimeters. This dimension was chosen based on the information contained in EPA's Technical Information Document - 010 (TID – 010) "Quadruplicate (Quad Train) Sampling Probe Arrangement". Both sampling trains were operated per the procedures and equations in Method 201A.

Three, five, and eight hour runs were performed, and the measured filterable $PM_{2.5}$ concentrations were compared between the two trains. The relative standard deviations (RSD) in measured $PM_{2.5}$ concentrations were 5.9, 8.4, and 5.2 percent for the three, five, and eight hour runs, respectively, with an average RSD of 6.5 percent. This meets the requirement in EPA Method 301 for precision (≤ 50 percent relative standard deviation) when comparing a proposed method to a validated method. Table 3.1 contains the data from the method comparison study.

Table 3.1 Method Comparison of Filterable $PM_{2.5}$ Concentrations

Run Duration (hours)	Train ID	Filterable PM (mg)	Filterable $PM_{2.5}$ (mg)	Sample Volume (dscf)	Percent Difference In Volume	Filterable PM (gr/dscf)	Filterable $PM_{2.5}$ (gr/dscf)	Relative Standard Deviation In $PM_{2.5}$ Concentrations
3	Standard	2.85	1.83	49.942		0.00088	0.00057	
3	Modified	3.15	1.97	49.312	-1.3	0.00099	0.00062	5.9
5	Standard	7.98	5.95	79.390		0.00155	0.00116	
5	Modified	7.29	5.24	78.256	-1.4	0.00144	0.00103	8.4
8	Standard	20.11	15.73	123.151		0.00252	0.00197	
8	Modified	17.55	14.78	124.854	1.4	0.00217	0.00183	5.2

3.2 PM Samples Generated and Their Analysis

Each of the EPA particulate measurement methods used in this study generates multiple discrete particulate matter samples. Determination of particulate emissions involves summing appropriate sample masses for each category of particulate. A unique identifier was used for each sample as noted in Table 3.2. Table 3.3 summarizes the combination of samples associated with each category of particulate.

Table 3.2 Samples Generated (Listed by Method)

Method	Sample Description	Mass ID
Old 202	Impinger contents plus water rinse of glassware	1
Old 202	Dichloromethane extraction of impinger contents plus rinse of glassware	2
Old 202	Post condenser un-heated filter (CPM filter)	2A[c]
New 202	Dropout and impinger contents plus water rinse of glassware	3
New 202	Hexane extraction of impinger contents plus rinse of glassware	4[a]
New 202	Post condenser un-heated filter (CPM filter)	5[b]
201A	Rinse of cyclone I (PM_{10} cut point)	6[d]
201A	Rinse of Cyclone IV ($PM_{2.5}$ cut point)	7
201A	Rinse of cyclone IV exit and filter holder front half	8
201A	In-stack unheated filter	9

[a] Glassware rinsed with acetone followed by two rinses with hexane
[b] Filter sample for New Method 202 extracted with water and hexane
[c] Filter sample for Old Method 202 extracted with water and dichloromethane
[d] Not collected for this study

Table 3.3 Sample Masses Required (Listed by Particulate Category)

Particulate Category	Required Masses
Filterable PM	6,7,8,9 Method 201A
Filterable PM_{10}[a]	7,8,9 Method 201A
Filterable $PM_{2.5}$	8,9 Method 201A
CPM	1,2,2A (Old Method 202) or 3,4,5 (New Method 202)
Total PM	1,2,2A,6,7,8,9 (Methods 201A + Old 202) or 3,4,5,6,7,8,9 (Methods 201A + New 202)
Total PM_{10}[a]	1,2,2A,7,8,9 (Methods 201A + Old 202) or 3,4,5,7,8,9 (Methods 201A + New 202)
Total $PM_{2.5}$	1,2,2A,8,9 (Methods 201A + Old 202) or 3,4,5,8,9 (Methods 201A + New 202)

[a]Not determined in this study

Method 201A rinse samples collected from the front-half of the sampling train (samples 7 and 8) were quantitatively transferred to 50 ml glass beakers. The acetone reagent was allowed to evaporate at ambient temperature and pressure in a laboratory hood. After drying, rinse samples 7and 8 were placed in desiccators, and weighed after an initial 24-hour holding time. Subsequent weights were obtained with a minimum of six hours elapsing between weight determinations. Samples were weighed multiple times until a difference of less than 0.5 milligrams was obtained between two consecutive weight determinations. The detected mass was determined as the arithmetic average of two consecutive weights that met the constant weight criterion of less than 0.5 mg difference in consecutive mass determinations. Sample masses determined for samples 7 and 8 were acetone blank corrected per the procedures outlined in Section 12.3 of EPA Method 201A. Filter samples collected from the front-half of the sampling train (sample 9) were placed in individual desiccators, with a constant weight determination obtained in the same manner as was done for samples 7 and 8.

CPM samples collected from the old Method 202 sampling train (samples 1, 2, and 2A) were processed as follows. The inorganic water samples (sample 1) were placed in separatory funnels and extracted three times with dichloromethane. The initial extraction was performed with the dichloromethane used to rinse the impingers during sample collection, and the succeeding extractions were performed with 75 ml of fresh dichloromethane. After extraction, the inorganic samples were taken to dryness in a 105°C oven in large glass beakers. The dry residue from the inorganic samples was rehydrated in 100 ml of water, and the solution titrated to a pH of 7 with ammonium hydroxide. *Titration of the inorganic samples is performed so that the hygroscopic nature of any acids present in the inorganic samples will be minimized.* After titration, the samples were taken to dryness in a 105°C oven in 50 ml glass beakers. After drying, the samples were placed in desiccators. A constant weight determination was obtained in the same manner as described for the Method 201A samples. The constant weights obtained for the inorganic samples were adjusted by subtracting the amount of ammonium consumed during the titration. The organic samples (sample 2) were combined with the inorganic samples in a separatory funnel for the initial extraction of the inorganic samples. After extraction, the organic samples were placed in 50 ml glass beakers along with the fresh dichloromethane used for the second and third extractions of the inorganic samples, and allowed to dry at ambient conditions in a laboratory hood. After drying in the hood, the organic samples were placed in desiccators and a constant weight determined as described for the Method 201A samples. The CPM filter samples (sample 2A) were processed per the procedures specified in the new Method 202. CPM filter samples were extracted three times with water, followed by three extractions with

dichloromethane in a sonic bath. Extractions from the CPM filter were combined with the appropriate organic or inorganic samples before extraction of the water samples was performed. *The procedures in the old Method 202 for the CPM filter specify determination of the filter weight gain, which is added to the total CPM weight determined for the organic and inorganic samples. The old Method 202 procedure does not provide any information about the speciation of the CPM captured on the CPM filter, so the method for processing the CPM filter in the new Method 202 was followed.*

Samples collected from the new Method 202 sampling train (samples 3, 4, and 5) were processed in the same manner as described for the old Method 202 samples, with the following exceptions:

1. The inorganic water samples (sample 3) were extracted three times with 30 ml of fresh hexane, with the hexane extractions being combined with the acetone and hexane rinses of the glassware (organic sample 4).
2. The inorganic water samples were reduced in volume in a 105ºC oven, but were removed from the oven while a minimum of 10 ml of liquid remained in the containers, and allowed to complete the drying cycle at ambient temperature and pressure in a laboratory hood. After drying at ambient temperature and pressure, the inorganic samples were rehydrated to a volume of 100 ml, and titrated to a pH of 7. The inorganic samples were placed back in the oven and reduced at 105ºC to not less than 10 ml, and allowed to dry again at ambient temperature and pressure in a laboratory hood. After drying, the inorganic samples were placed in desiccators and a constant weight determined as described for the Method 201A samples above.
3. The CPM filter samples (sample 5) were extracted three times with water, followed by three extractions with hexane in a sonic bath. Extractions from the CPM filter were combined with the appropriate organic or inorganic samples before extraction of the water samples was performed. In addition to gravimetric analysis of the CPM samples, all inorganic CPM samples were analyzed by ion chromatography for sulfate, nitrate, chloride, ammonium, calcium, and sodium.

3.3 Limits of Detection

All measurements have errors associated with them. These errors consist of *systematic errors*, if the method has a measurement bias, and *random errors*. Random errors cause replicate measurements to vary from run to run. When the number of replicates is sufficiently high, the average of such random errors tends to approach zero. In general, the magnitude of the random error expressed as a fraction of the measured value, decreases as the value of the measured parameter increases. In practice, when the measured value of a parameter is much higher than the potential for random error, there is a high degree of confidence in the measured value obtained from a single or a few runs. However, as the measured value decreases, the potential contribution of the random error to the measured value increases, thus decreasing the confidence level in the measured value from a single or a few runs until the point where the measured value cannot be distinguished from the random error.

Analytical chemists have long been concerned about their ability to determine whether or not an analyte is present in a sample and, if it is, its true level. This has given rise to two important concepts: limit of detection (LOD) and limit of quantitation. In general terms, the detection limit of an analytical method is defined as the lowest concentration that can be distinguished from the blank at a defined level of statistical significance. The quantitation limit for a method is defined as the smallest concentration of the analyte which can be measured where the accuracy achieves the objectives of the measurement. In the most recent version of EPA Method 301 the LOD is defined as being:

> *"the lowest level above which you may obtain quantitative results with an acceptable degree of confidence.* [which] *is defined as three times the standard deviation, S_o, at the blank level* [for seven replicate analyses]. [The LOD can also be defined as] *the lowest quantity of a substance that can be distinguished from the absence of that substance (i.e., blank value) with a stated level of confidence."* (USEPA 2011).

At the LOD there is a 99 percent confidence level that the presence of the analyte has been detected. However, there is a significant amount of uncertainty with regard to the measured value at the detection limit. In the previous version of EPA Method 301 there was a procedure for determining a quantitation limit termed the Practical Limit of Quantitation (PLQ). The PLQ is defined as:

> "[ten]*times the standard deviation, s_0, at the blank level. This PLQ corresponds to an uncertainty of ± 30 percent at the 99 – percent confidence level* [for seven replicate analyses]*."* (USEPA 1992)

The PLQ is a useful tool in determining the quality of data generated. When seven replicate analyses are performed, the PLQ is approximately three times the Method Detection Limit (MDL). The EPA has published MDLs for Methods 201A and 202. These MDLs are analogous to a LOD and take into account the systematic and random errors associated with operation of the sampling train and collection and analysis of the PM samples. PLQs were not published for Methods 201A and 202, however they may be estimated as being three times the MDL. *It should be understood that the MDLs published for Methods 201A and 202 were determined at a single source, with all testing and sample analysis performed by a single test team and analytical laboratory. Therefore, the published MDLs for these methods should be viewed as general guidelines. If an evaluation of the MDLs for Methods 201A and 202 were performed on multiple sources, using multiple test teams and laboratories, the MDLs resulting from such a study would likely be higher.*

The accuracy of environmental measurements is directly related to the sample concentration or mass detected, and where this detected concentration or mass falls in relation to the LOD and PLQ. As noted above, there is significant uncertainty associate with measurements at or near the LOD. While there is a high degree of certainty that the presence of a given analyte has been detected at the LOD, there is little confidence in the measured value of the analyte. Therefore, it is important to always strive to collect enough sample such that the concentration or mass of the analyte is at or above the PLQ. Figure 3.3 illustrates the relationships between the LOD, the PLQ, analyte concentration, and measurement uncertainty.

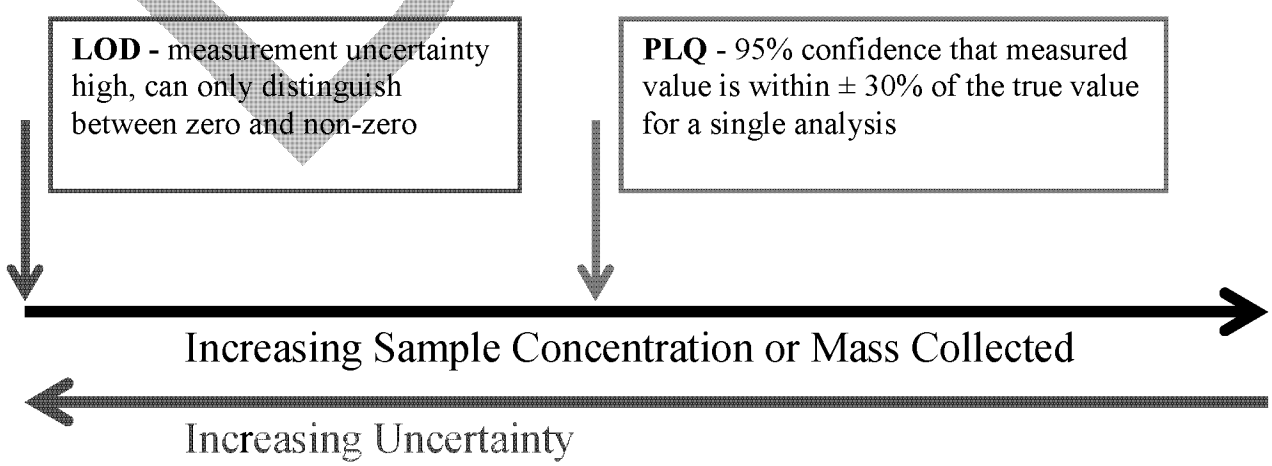

Figure 3.3 Relationships Between LOD, PLQ, Sample Concentration, and Measurement Uncertainty

Table 3.3 summarizes the published MDLs and estimated PLQs for Methods 201A and 202. The published MDLs and estimated PLQs in Table 3.4 were used in evaluating the PM concentrations and emissions generated in this study.

Table 3.4 EPA Published Method Detection Limits and Estimated Practical Limits of Quantitation

	Method 201A		Method 202[b]	
Parameter	MDL	PLQ[a]	MDL	PLQ[a]
Filterable PM	2.54	7.62		
Filterable PM_{10}	1.44	4.32		
Filterable $PM_{2.5}$	1.35	4.05		
Condensable Organic			0.5	1.5
Condensable Inorganic			3.5	10.5
Total Condensable PM			4.0	12.0

All masses in milligrams. [a]PLQ values estimated as three times the MDL.
[b]EPA Method 202 as promulgated in 2010.

3.4 Reporting of Data

Particulate concentrations were determined by summing the appropriate sample masses for a given category of particulate and dividing this summed mass by the volume of flue gas sampled, corrected to standard conditions (68°F and 29.92 in. Hg). Particulate concentrations are reported in grains per dry standard cubic foot (gr/dscf) and corrected to 3 percent oxygen. For example, the filterable $PM_{2.5}$ sample consists of the sum of sample masses Nos. 8 and 9 as defined in Table 3.2 above. If sample mass No. 8 was 2 mg and sample mass No. 9 was 3 mg, the filterable $PM_{2.5}$ mass would be 5 mg. If the volume of flue gas sampled was 35.315 dscf, and the stack oxygen content were 5 percent, the filterable $PM_{2.5}$ concentration corrected to 3 percent oxygen would be 0.002 gr/dscf. Equation 3.1 illustrates the concentration calculation. Oxygen content is on a dry basis.

$$\frac{5\ mg\ PM_{2.5}}{35.315\ dscf} \times \frac{1\ grain}{64.8\ mg} \times \frac{(20.9 - 3.0_{oxygen\ correction})}{(20.9 - 5.0_{actual\ oxygen\ content})} = \mathbf{0.002}\frac{grains}{dscf}$$

Equation 3.1 Calculation of Filterable $PM_{2.5}$ Concentration, Corrected to 3 Percent Oxygen

PM emissions are reported in pounds per million Btu of heat input (lb/10^6 Btu). Equation 19 – 1 from EPA Method 19 was used to normalize PM emissions to heat input. The default F_d –factor for natural gas combustion of 8710 dry-standard cubic feet of flue gas per million Btu of heat input (zero percent oxygen basis) was used in the calculation. Using the example data above and Equation 19 – 1 from EPA Method 19, the calculated filterable $PM_{2.5}$ emission rate would be 0.004 lb/10^6 Btu. Equation 3.2 illustrates the PM emission rate calculation. The F_d –factor from EPA Method 19 is based on zero percent oxygen, which requires the oxygen correction illustrated in equation 3.2.

$$\frac{5\ mg\ PM_{2.5}}{35.315\ dscf} \times \frac{1\ grain}{64.8\ mg} \times \frac{1\ lb}{7000\ grains} \times \frac{8710\ dscf}{10^6\ Btu} \times \frac{(20.9 - 0.0_{oxygen\ correction})}{(20.9 - 5.0_{actual\ oxygen\ content})}$$

$$= \mathbf{0.004} \frac{lb\ Filterable\ PM_{2.5}}{10^6\ Btu}$$

Equation 3.2 Calculation of Filterable $PM_{2.5}$ Emission Rate

The following protocol was followed when carrying out concentration and emission calculations:

i. The detected mass for a given sample was used to calculate the concentration and emission rate.
ii. If the detected mass was a negative value for a given sample, zero was substituted for the detected mass.
iii. If the mass collected for an individual sample run for a given category of particulate matter was above the MDL but below the PLQ for the method used, the results were shaded in the data tables to alert the reader to the fact that there is a higher uncertainty associated with these data when compared to data above the PLQ.
iv. If the mass collected for a sample run for a given category of particulate matter was below the MDL, the results were preceded by the less than symbol. These values are also shaded in the data tables.
v. Mean values for a given category of particulate matter were calculated as the arithmetic average of the individual run values. Mean values for which the underlying individual run values were all above the MDL, but not all were above the PLQ are shaded in the data tables to indicate that there is more uncertainty associated with this value when compared to mean values where all individual run data are above the PLQ. Mean values are preceded by the less than symbol (<) and shaded in the data tables if at least one individual run value was below the MDL to indicate that the mean value is based on at least one non-detect value.

Table 3.5 illustrates the data reporting protocols described above.

Table 3.5 Examples of Data Reporting Protocols

	Run 1	Run 2	Run 3	Run 4	Mean
	(lb/10^6 Btu)				
Filterable PM	0.214	0.076	0.122	0.062	0.119[a]
Filterable $PM_{2.5}$	0.016	0.021	0.019	0.017	0.012[b]
Condensable PM	0.029	<0.023	<0.015	0.025	<0.023[c]

[a]All samples are above the PLQ.
[b]All samples are above the MDL, and at least one sample is below the PLQ.
[c]At least one sample is above the MDL.

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3.5 Quality Assurance

Quality assurance measures for field implementation of EPA Methods 201A and 202 involved use of appropriate materials of construction for the sampling train, pre and post leak checks of the sampling train, pre and post leak checks of the pitot tube, visual inspection of the pitot tube, collection of field train and reagent blanks, and calibration of thermocouples, pyrometers, absolute pressure manometers, nozzles, and dry gas meters.

Laboratory quality assurance measures included the use of beaker blanks, lab reagent blanks, control of relative humidity and temperature in the room where samples were weighed, calibration of the balance with Class S weights, and use of an anti-static device prior to placing samples on the balance. A five-place Mettler-Toledo balance (model No. XS205) was used for sample mass determinations, and the anti-static device used was a Mettler-Toledo unit, model No. X2000. Guidelines in the American Society for Testing and Materials (ASTM) document D 6552-00, "Standard Practice for Controlling and Characterizing Errors in Weighing Collected Aerosols," were followed during gravimetric analysis of samples (ASTM 2000).

3.6 Source Characteristics

The boiler tested in this study is a natural gas fired package boiler with a rated steaming capacity of 180,000 pounds per hour at 650 pounds per square inch (gauge). A single low NO_x burner is used, along with 10 percent flue gas recirculation. The performance guarantee from the manufacturer for PM emissions is 0.005 pound per million Btu (lb/10^6 Btu). Figure 3.4 illustrates the stack and sample port arrangement.

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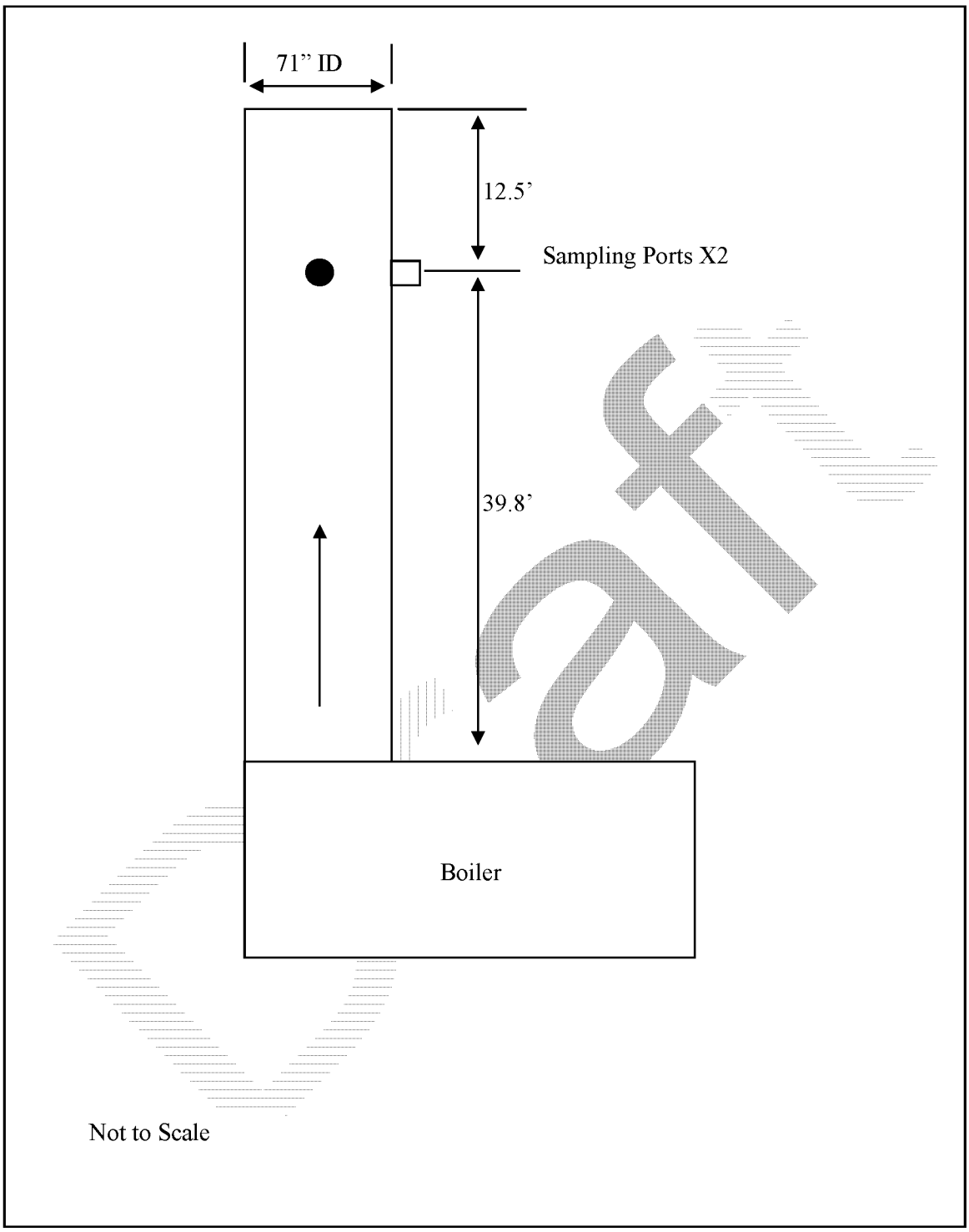

Figure 3.4 Stack Diagram and Sampling Port Arrangement

4.0 RESULTS

Data from three paired-train sample runs are presented in this section, along with data from the train blanks. Detailed test data are provided in Appendix A. The train blank runs reported in this study were carried out in the laboratory immediately prior to the sampling trip. The train blanks for Method 201A, old Method 202, and new Method 202 quantified in conjunction with this study are reported in Tables A.3 and A.4, respectively. The train blank for Method 201A was 0.28 mg and that for new Method 202 (organic and inorganic fractions) was 5.39 mg, yielding a total $PM_{2.5}$ train blank of 5.67 mg. The train blank calculated during this study was comparable to the train blank of 5.70 mg established earlier by NCASI from seven replicate field and laboratory studies, carried out over a period of several years and involving multiple sampling personnel. The results are also comparable to the train blank of 5.33 mg reported by EPA in its evaluation of the new Method 202.

PM concentrations and emissions (including those for the train blank) were calculated based on the average flue gas sample volume collected, in conjunction with the average flue gas oxygen content. PM concentrations are corrected to three percent oxygen. The default F_d – factor for natural gas combustion listed in Method 19 was used along with Equation 19 – 1 from EPA Method 19 to calculate PM emissions. Detailed test data are provided in Appendix A.

PM data for the sample train that used the new version of Method 202 are presented in Table 4.1. All of the filterable PM and filterable $PM_{2.5}$ samples were below their respective PLQs. One filterable PM sample was below the MDL, and all of the filterable $PM_{2.5}$ samples were below the MDL. All of the organic and inorganic CPM samples were above their respective PLQs, with one run having the total CPM sample being below the PLQ but above the MDL after the maximum allowed train blank correction (2 mg) was applied to the total CPM sample masses. Filterable PM concentrations ranged from <0.00009 to 0.00013 gr/dscf @ 3% O_2, and averaged <0.00010 gr/dscf @ 3% O_2. The train blank for filterable PM was approximately 40 percent of the average measured filterable PM at <0.00004 gr/dscf @ 3% O_2. Filterable $PM_{2.5}$ concentrations ranged from <0.00002 to <0.00004 gr/dscf @ 3% O_2, and averaged <0.00003 gr/dscf @ 3% O_2. The train blank for filterable PM was approximately 33 percent of the average measured filterable PM at <0.00001 gr/dscf @ 3% O_2. Total CPM concentrations ranged from 0.00039 to 0.00073 gr/dscf @ 3% O_2, and averaged 0.00053 gr/dscf @ 3% O_2. The train blank for total CPM was approximately 34 percent of the average measured total CPM at 0.00018 gr/dscf @ 3% O_2. Direct $PM_{2.5}$ concentrations ranged from <0.00042 to <0.00076 gr/dscf @ 3% O_2, and averaged <0.00056 gr/dscf @ 3% O_2. The train blank for direct $PM_{2.5}$ was approximately 41 percent of the average measured direct $PM_{2.5}$ at 0.00023 gr/dscf @ 3% O_2.

Filterable PM emissions, for the sample train that used the new Method 202, ranged from <0.00013 to 0.00019 lb/10^6 Btu, and averaged <0.00015 lb/10^6 Btu. Filterable $PM_{2.5}$ emissions ranged from <0.00004 to <0.00006 lb/10^6 Btu, and averaged <0.00005 lb/10^6 Btu. Total CPM emissions ranged from 0.00057 to 0.00106 lb/10^6 Btu, and averaged 0.00077 lb/10^6 Btu. Direct $PM_{2.5}$ emissions ranged from <0.00061 to <0.00110 lb/10^6 Btu, and averaged <0.00082 lb/10^6 Btu.

PM data for the sample train that used the old version of Method 202 are presented in Table 4.2. All of the filterable PM and filterable $PM_{2.5}$ samples were below their respective MDLs and PLQs. One cyclone IV exit rinse sample (sample 8 for run one) was inadvertently combined with the rinse of the cyclone IV body (sample 7 for run one). Therefore, no filterable or direct $PM_{2.5}$ data exist for this sample run. All of the organic, inorganic, and total CPM samples were above their respective PLQs. Filterable PM concentrations ranged from <0.00005 to <0.00008 gr/dscf @ 3% O_2, and averaged <0.00007 gr/dscf @ 3% O_2. The train blank for filterable PM was approximately 57 percent of the average measured filterable PM at <0.00004 gr/dscf @ 3% O_2. Filterable $PM_{2.5}$ concentrations ranged from <0.00001 to <0.00003 gr/dscf @ 3% O_2, and averaged <0.00002 gr/dscf @ 3% O_2. The train blank for filterable PM was approximately 50 percent of the average measured filterable PM at

<0.00001 gr/dscf @ 3% O_2. Total CPM concentrations ranged from 0.00072 to 0.00113 gr/dscf @ 3% O_2, and averaged 0.00089 gr/dscf @ 3% O_2. The train blank for total CPM was approximately 15 percent of the average measured total CPM at 0.00013 gr/dscf @ 3% O_2. Direct $PM_{2.5}$ concentrations ranged from <0.00082 to <0.00116 gr/dscf @ 3% O_2, and averaged <0.00090 gr/dscf @ 3% O_2. The train blank for direct $PM_{2.5}$ was approximately 16 percent of the average measured direct $PM_{2.5}$ at 0.00014 gr/dscf @ 3% O_2.

Filterable PM emissions, for the sample train that used the old Method 202, ranged from <0.00007 to 0.00012 lb/10^6 Btu, and averaged <0.00010 lb/10^6 Btu. Filterable $PM_{2.5}$ emissions ranged from <0.00002 to <0.00004 lb/10^6 Btu, and averaged <0.00003 lb/10^6 Btu. Total CPM emissions ranged from 0.00104 to 0.00165 lb/10^6 Btu, and averaged 0.00129 lb/10^6 Btu. Direct $PM_{2.5}$ emissions ranged from <0.00119 to <0.00169 lb/10^6 Btu, and averaged <0.00131 lb/10^6 Btu.

Table 4.1 Natural Gas Combustion PM Data for Method 201A and New Method 202

	Train[1] Blank	Run 1	Run 2	Run 3	Mean
	(gr/dscf @ 3% O_2)				
Filterable PM	<0.00004	0.00013	<0.00009	0.00009	<0.00010
Filterable $PM_{2.5}$	<0.00001	<0.00004	<0.00003	<0.00002	<0.00003
Organic CPM	0.00009	0.00009	0.00008	0.00026	0.00015
Inorganic CPM	0.00013	0.00045	0.00038	0.00053	0.00045
Total CPM	0.00018	0.00047	0.00039	0.00073	0.00053
Direct $PM_{2.5}$	**<0.00019**	**<0.00051**	**<0.00042**	**<0.00076**	**<0.00056**
SO_4	0.00001	0.00027	0.00028	0.00038	0.00031
	(lb/10^6 Btu)[2]				
Filterable PM	<0.00006	0.00019	<0.00013	0.00013	<0.00015
Filterable $PM_{2.5}$	<0.00001	<0.00006	<0.00004	<0.00004	<0.00005
Organic CPM	0.00010	0.00013	0.00012	0.00038	0.00021
Inorganic CPM	0.00017	0.00065	0.00055	0.00078	0.00066
Total CPM	0.00027	0.00069	0.00057	0.00106	0.00077
Direct $PM_{2.5}$	**<0.00028**	**<0.00075**	**<0.00061**	**<0.00110**	**<0.00082**
SO_4	0.00002	0.00039	0.00040	0.00056	0.00045

[1]Train blank values estimated based on the average flue gas volume sampled and average flue gas oxygen content.
[2]PM emissions calculated using EPA Method 19 equation 19-1 and the default F_d-factor for natural gas.

Table 4.2 Natural Gas Combustion PM Data for Method 201A and Old Method 202

	Train[1] Blank	Run 1	Run 2	Run 3	Mean
	(gr/dscf @ 3% O_2)				
Filterable PM	<0.00004	<0.00008	<0.00008	<0.00005	<0.00007
Filterable $PM_{2.5}$	<0.00001	No Data	<0.00003	<0.00001	<0.00002
Organic CPM	0.00002	0.00005	0.00006	0.00007	0.00006
Inorganic CPM	0.00011	0.00071	0.00112	0.00078	0.00087
Total CPM	0.00013	0.00072	0.00113	0.00081	0.00089
Direct $PM_{2.5}$	**0.00014**	**No Data**	**0.00116**	**0.00082**	**0.00090**
SO_4	0.000004	0.00047	0.00084	0.00061	0.00064
	(lb/10^6 Btu)[2]				
Filterable PM	<0.00005	<0.00012	<0.00012	<0.00007	<0.00010
Filterable $PM_{2.5}$	<0.00002	No Data	<0.00004	<0.00002	<0.00003
Organic CPM	0.00003	0.00007	0.00009	0.00011	0.00009
Inorganic CPM	0.00016	0.00104	0.00163	0.00113	0.00127
Total CPM	0.00019	0.00104	0.00165	0.00117	0.00129
Direct $PM_{2.5}$	**0.00021**	**No Data**	**0.00169**	**0.00119**	**0.00131**
SO_4	0.00001	0.00068	0.00122	0.00089	0.00093

[1]Train blank values estimated based on the average flue gas volume sampled and average flue gas oxygen content.
[2]PM emissions calculated using EPA Method 19 equation 19-1 and the default F_d-factor for natural gas.

5.0 DISCUSSION

5.1 Increased Positive Biases

The capability of EPA Methods 201A and 202 to measure direct $PM_{2.5}$ emissions on low concentration/low emitting sources, such as a natural gas fired boiler, is constrained by *random errors* associated with these methods. Collecting enough particulate matter to be at least three times the LOD of the methods on low concentration sources requires an inordinately long sample time. While increasing the sampling time allows the user to collect enough sample mass, thereby increasing the certainty in measurements, it adds a further complication. This revolves around the increased potential for positive bias in estimated CPM emissions due to the oxidation of sulfur dioxide to sulfate in the sampling train. The new Method 202 minimizes the sulfur dioxide bias by using a water jacketed condenser and dropout to prevent bubbling of the flue gas through the condensed water. The majority of sulfur dioxide that is absorbed through the gas liquid interface in the dropout is removed from the condensed water by purging with nitrogen. This works reasonably well when run times are limited to two hours or less. However, for a 24 hour sample run, as was done for this study, there is ample time for any sulfur dioxide that is absorbed in the condensed water to be oxidized to sulfate, and thus impart a positive bias to the estimated CPM emissions.

The inorganic CPM samples collected during this study were analyzed by ion chromatography for sulfate, nitrate, chloride, ammonium, calcium, and sodium. The largest component of the inorganic CPM samples was sulfate, at approximately 87 percent of the total inorganic sample mass. Sulfate as a percent of total CPM was 60 and 72 percent for the new and old Method 202, respectively. As discussed earlier, sulfate in CPM samples can be a result of oxidation of sulfur dioxide absorbed into the condensed water, which is a method artifact, or due to sulfur trioxide in the flue gas, which is the precursor to sulfuric acid, and a legitimate component of CPM emissions. It is unknown if the sulfate present in the CPM samples is due to oxidation of sulfur dioxide, hydration of sulfur trioxide, or a combination of the two. However, as indicated in Table 5.1, the inorganic CPM captured by the old Method 202 was almost twice as much as that captured by the new Method 202, suggesting that a significant portion of the sulfate present in the CPM samples is due to oxidation of sulfur dioxide. The stack temperatures, and thus the in-stack filter temperatures, were never above 325 °F, which is below the expected dew point of sulfuric acid. If sulfuric acid was present in the flue gas, it would have been expected to be captured predominantly on the in-stack filter. This further supports the likelihood that the majority of sulfate present in the CPM samples was due to oxidation of sulfur dioxide. Table 5.1 summarizes the ion chromatography analysis of the inorganic CPM samples. Table values are in percent of total inorganic sample mass. Detailed ion chromatography data are presented in Appendix A.

Table 5.1 Ion Chromatography Results for Inorganic CPM Samples

	New Method 202 Inorganic Samples				
	Percent of Inorganic Sample on a Mass Basis				
Run ID	Train Blank	Run 1	Run 2	Run 3	Run Average
Sulfate	25.2	86.8	87.0	87.0	86.9
Nitrate	8.5	0.3	0.3	0.2	0.2
Chloride	18.0	0.3	0.3	0.2	0.2
Ammonium	3.8	6.0	6.4	7.6	6.7
Calcium	26.1	1.4	1.1	1.1	1.2
Sodium	18.4	5.3	4.8	3.9	4.7
Inorganic Sample Mass Collected (mg)	*3.87*	*13.45*	*10.62*	*16.02*	*13.36*
	Old Method 202 Inorganic Samples				
	Percent of Inorganic Sample on a Mass Basis				
Run ID	Train Blank	Run 1	Run 2	Run 3	Run Average
Sulfate	5.7	86.6	87.5	87.5	87.2%
Nitrate	4.9	0.2	0.1	0.1	0.1%
Chloride	54.5	0.2	0.1	0.1	0.1%
Ammonium	2.6	5.7	6.3	7.0	6.3%
Calcium	9.2	2.0	1.8	1.2	1.7%
Sodium	23.1	5.4	4.2	4.1	4.6%
Inorganic Sample Mass Collected (mg)	*3.82*	*21.42*	*31.04*	*23.34*	*25.27*

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5.2 Train Blank Adjustment

Another issue with EPA Method 202 is a restriction on the train blank adjustment allowed for this method. As promulgated, EPA Method 202 allows the tester to subtract the field train blank from the detected CPM sample mass, with a maximum allowable correction of two milligrams. It is unclear as to why the blank correction was restricted to two milligrams. During EPA's field evaluation of Method 202, the average field train blank for seven replicate samples was 5.33 milligrams, with train blanks having ranged from 4.60 to 6.22 milligrams for total CPM. As discussed earlier, NCASI experience with train blank sample weights for Method 202 is consistent with the data generated in EPA's field evaluation study.

Restricting the extent of train blank correction imparts a positive bias in estimated CPM emissions. This positive bias is further accentuated in the case of low emitting sources like the natural gas boiler tested during this study. The amount of positive bias imparted to the estimated CPM emissions is a function of the mass detected in the train blank and in the samples from the individual runs. For example, if a tester had a train blank detected mass of 5 milligrams for total CPM, and the detected total CPM mass for a given sample run was 7 milligrams, applying the maximum allowed correction to the detected CPM mass would yield an adjusted CPM sample mass of 5 milligrams. The actual CPM mass collected would be estimated as the 7 milligrams detected minus the 5 milligrams from the train blank, or 2 milligrams. For this example, not allowing the full train blank correction imparts a positive bias of 250% in the estimated CPM emissions.

EPA Method 201A has a similar issue to that encountered with Method 202 in regard to adjustment of detected sample masses. In Method 201A, the tester is allowed to adjust the detected sample masses for the residue concentration in the rinse reagent, but is not allowed to make an adjustment based on the train blank detected mass. This mass adjustment is limited to the residue that would be expected for a rinse reagent with a residue content not exceeding one part per million on a mass basis. In this study, the amount of sample mass correction for residue in the rinse reagent for Method 201A was an exceedingly small fraction of the detected mass in the train blank samples. For example, in the sampling train that used the new Method 202, the raw detected mass for filterable $PM_{2.5}$ was 0.32 milligrams. The residue correction for the rinse reagent for this sample was 0.03 milligrams, or about 9 percent of the raw detected mass. A similar result was obtained in the sampling train that used the old Method 202, with a raw detected mass of 0.42 milligrams, and a rinse reagent residue correction of 0.02 milligrams, or approximately 5 percent of the raw detected mass.

Figures 5.1 through 5.3 illustrate the positive bias associated with not allowing a full train blank correction for Methods 201A and 202. The figures display the emission rate calculated as per the procedures in the methods, as promulgated, and the emission rate calculated when the full train blank is subtracted from the sample masses. Data in Figures 5.1 through 5.3 are based on the average of three 24-hour runs from the sampling train that used the new Method 202. The estimated positive bias in filterable $PM_{2.5}$, CPM, and direct $PM_{2.5}$ emissions, calculated with the allowed sample mass adjustments, was approximately 42, 28, and 29 percent, respectively.

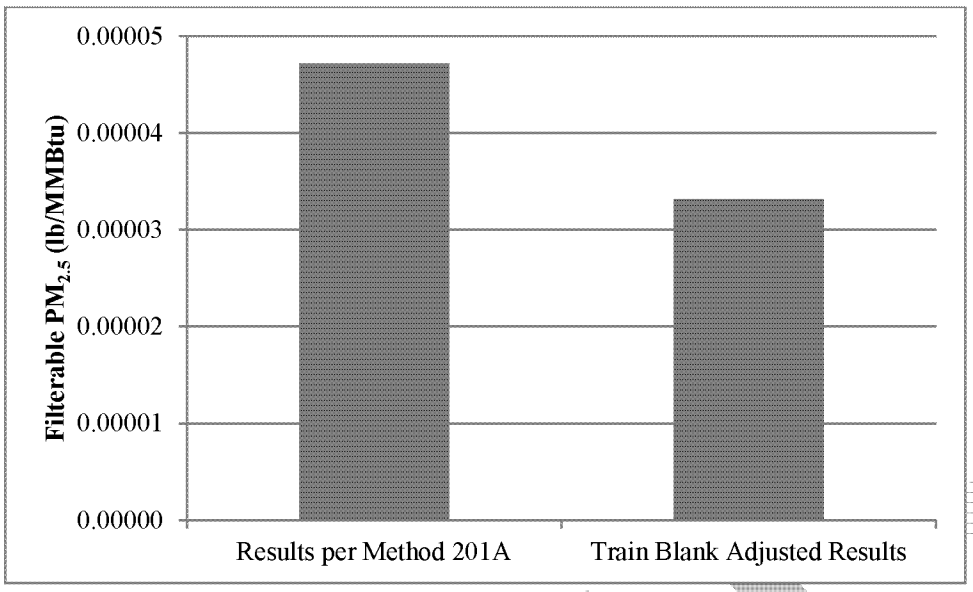

Figure 5.1 Effect of Train Blank Adjustment on the Filterable $PM_{2.5}$ Emission Estimate

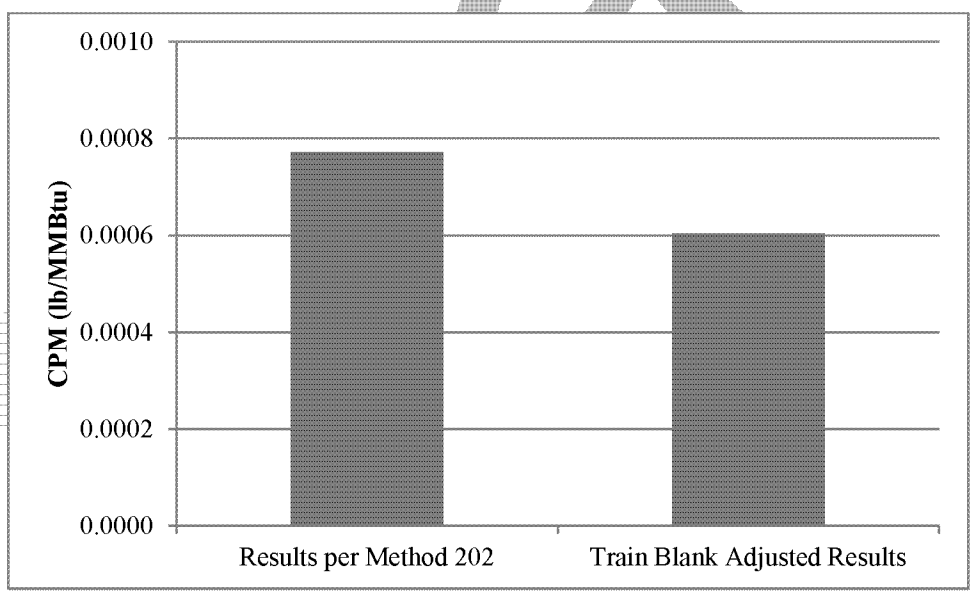

Figure 5.2 Effect of Train Blank Adjustment on the CPM Emission Estimate

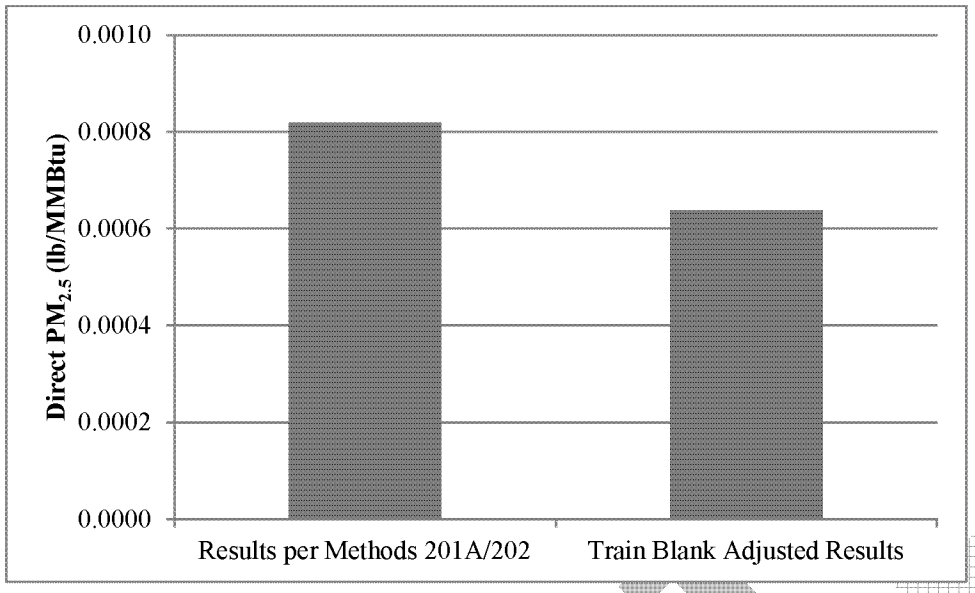

Figure 5.3 Effect of Train Blank Adjustment on Direct $PM_{2.5}$ Emission Estimate

5.3 Comparison to AP-42 Emission Factors

As was mentioned in the introduction to this report, the AP-42 emission factors for particulate matter from natural gas combustion are suspected of being biased high. The AP-42 emission factors for particulate matter emissions from natural gas combustion carry a quality rating of B for filterable PM, and a quality rating of D for CPM. Each emission factor is classified based on the quality of the data underlying the emission factor, with ratings ranging from A (excellent) through E (poor). The AP-42 emission factor for filterable PM is listed as being 1.9 pounds per million standard cubic feet of natural gas combusted (lb/10^6 scf). Footnotes to the table direct the reader to convert the table values into the pounds per million Btu by dividing the table value by 1020. Another footnote in the table indicates that all PM emissions from natural gas combustion are assumed to be in the one micron range. Thus the AP-42 emission factor for filterable $PM_{2.5}$ emissions is 0.00186 lb/10^6 Btu. The AP-42 emission factor for CPM emissions from natural gas combustion is listed at 5.7 lb/10^6 scf of natural gas combusted, or 0.00559 lb/10^6 Btu.

In comparing the data generated from this study to the AP-42 emission factors, it is apparent that, despite the probable positive bias in the NCASI data, the AP-42 emission factors for PM from natural gas combustion are indeed biased high by a significant amount. The AP-42 emission factor for filterable $PM_{2.5}$ emissions from natural gas combustion was approximately 37 times greater than what was measured in this study. Likewise, the AP-42 emission factor for CPM emissions from natural gas combustion was approximately 7 times greater than that measured in this study, and total direct $PM_{2.5}$ emissions measured in this study were almost a magnitude of order lower than the AP-42 emission factor. Figures 5.4 through 5.6 show the comparison of the train blanks and 3-run averages to the respective AP-42 values for filterable $PM_{2.5}$, CPM, and direct $PM_{2.5}$.

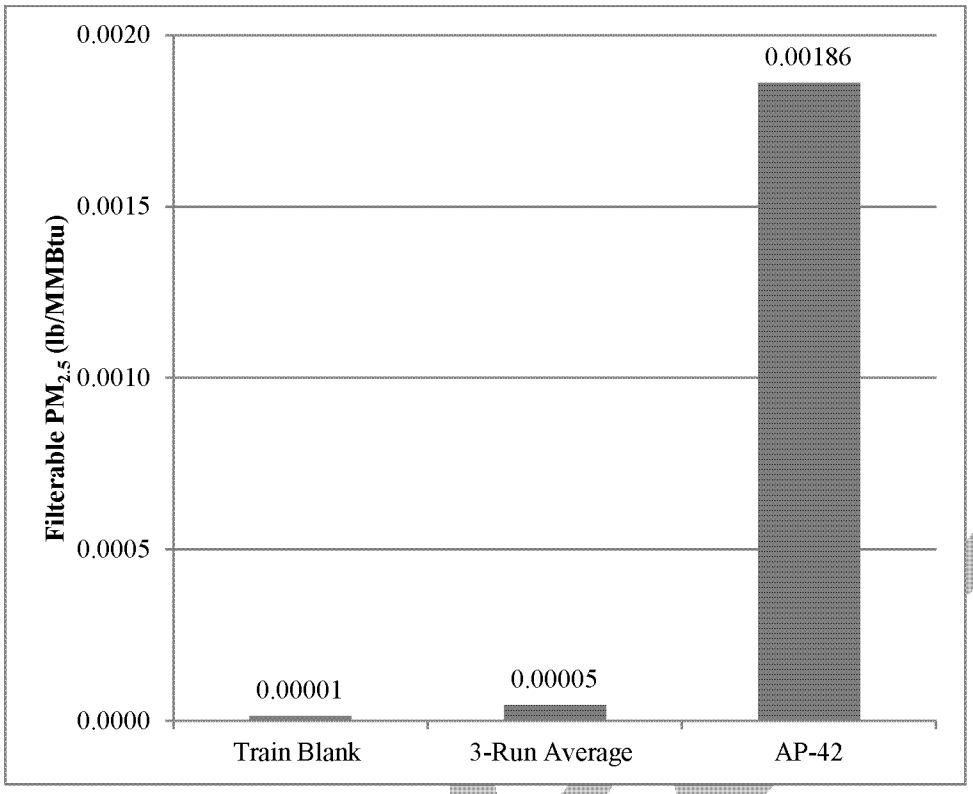

Figure 5.4 Comparison of Measured Filterable $PM_{2.5}$ to AP-42 Emission Factor

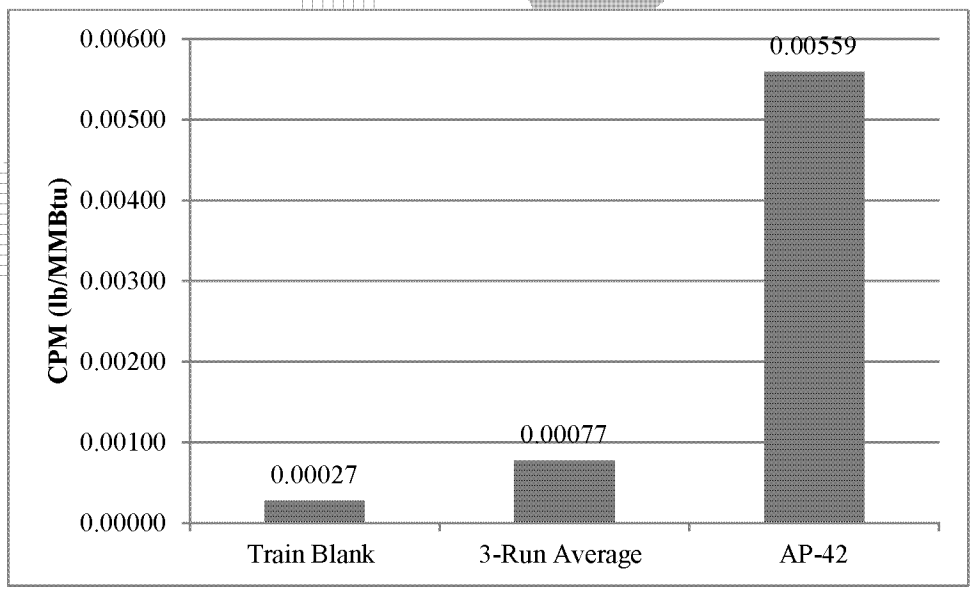

Figure 5.5 Comparison of Measured CPM to AP-42 Emission Factor

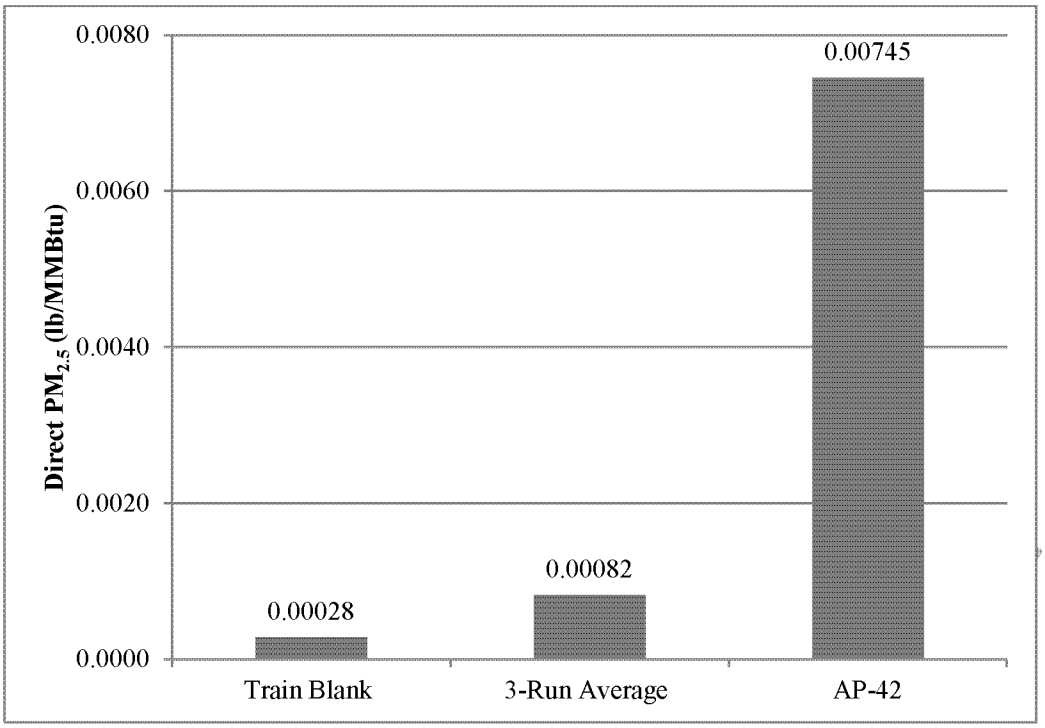

Figure 5.6 Comparison of Measured Direct $PM_{2.5}$ to AP-42 Emission Factor

6.0 SUMMARY AND CONCLUSIONS

$PM_{2.5}$ emissions from a natural gas-fired boiler were tested using Method 201A and 202 during this study. 24-hr sampling runs were carried out with the objective of collecting adequate PM sample mass (at levels close to the PLQ) to allow for increased certainty in the gravimetric measurements. However, the increased sampling times come with an associated drawback in that it increases the potential for positive biases due to the potential oxidation of SO_2 to sulfate in Method 202. Additionally, the absence of a train blank correction in Method 201A and a restriction on the amount of train blank correction for Method 202 can also impart a positive bias on reported direct $PM_{2.5}$ emissions.

Another important consideration in assessing the impact of the train blank correction on reported direct $PM_{2.5}$ emissions is the sampling time. As discussed in Figures 5.1 through 5.3, the bias associated with not using the appropriate train blank correction, on reported direct $PM_{2.5}$ emissions, was ~ 30%. The extent of this bias would increase as the sampling times are reduced (since the total mass collected would now be lower, thereby making the train blank a more predominant fraction of the total mass collected). For instance, if the same source were sampled using a 3-hr sampling run, the impact of subtracting only the allowed 2 mg train blank correction (as opposed to 5.67 mg) would result in ~ 300% positive bias in reported CPM emissions.

The findings from this study highlight the issues relative to the use of Methods 201A/202, as promulgated, for measuring filterable $PM_{2.5}$ and CPM emissions from low-emitting sources like natural gas-fired boilers. Additionally, the study also leaves unanswered questions on the potential for positive biases in Method 202 due to artifact formation, especially for longer sampling runs.

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APPENDIX A

DETAILED NCASI $PM_{2.5}$ TEST DATA FOR A NATURAL GAS-FIRED BOILER

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Table A.1 Natural Gas Fired Boiler Particulate Data – EPA Method 201A and New Method 202

Run ID		**Run 1**	**Run 2**	**Run 3**	**Mean**
Test Methods		EPA Methods 201A and 202 (2010)			
Total Run Time	(min.)	1440	1440	1440	
Natural Gas Firing Rate	(MCFH)	145.9	152.1	152.9	
Test Parameters					
Stack Pressure	(in.Hg)	28.26	28.05	28.61	
Stack Temperature	(°F)	321	324	323	
Stack Flow Rate	(dscfm)	24143	25151	25201	
Percent O_2		2.3	2.3	2.2	
Percent CO_2		10.3	10.5	10.0	
Percent H_2O		18	18	17	
Total DGM Volume	(dscf)	446.571	413.623	444.148	
Percent Isokinetic		86.8	84.4	83.7	
Cyclone 4 Dp50	(microns)	2.48	2.47	2.55	
Gravimetric Data		**(mg)**			
Filterable PM		3.92	2.57	2.83	
Filterable $PM_{2.5}$		1.32	0.91	0.81	
Condensible PM Hexane Soluble		2.76	2.29	7.92	
Condensible PM Water Soluble		13.45	10.62	16.02	
Concentrations		**(gr/dscf) @ 3% O_2**			
Filterable PM		0.00013	0.00009	0.00009	0.00011
Filterable $PM_{2.5}$		0.00004	0.00003	0.00002	0.00004
Condensible PM		0.00047	0.00039	0.00073	0.00043
Direct $PM_{2.5}$		**0.00051**	**0.00042**	**0.00076**	**0.00047**
SO_4		0.00027	0.00028	0.00038	0.00027
Mass Emission Rates		**(tons/year)**			
Filterable PM		0.121	0.089	0.091	0.105
Filterable $PM_{2.5}$		0.039	0.030	0.025	0.035
Condensible PM		0.445	0.384	0.721	0.415
Direct $PM_{2.5}$		**0.484**	**0.414**	**0.746**	**0.449**
SO_4		0.253	0.272	0.378	0.262
Normalized Emissions		**(lb/10^6)**			
Filterable PM		0.00019	0.00013	0.00013	0.00016
Filterable $PM_{2.5}$		0.00006	0.00004	0.00004	0.00005
Condensible PM		0.00069	0.00057	0.00106	0.00063
Direct $PM_{2.5}$		**0.00075**	**0.00061**	**0.00110**	**0.00068**
SO_4		0.00039	0.00040	0.00056	0.00040

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Table A.2 Natural Gas Fired Boiler Particulate Data – EPA Method 201A and Old Method 202

Run ID		**Run 1**	**Run 2**	**Run 3**	**Mean**
Test Methods		EPA Methods 201A and 202 (1991)			
Total Run Time	(min.)	1440	1440	1440	
Natural Gas Firing Rate	(MCFH)	145.9	152.1	152.9	
Test Parameters					
Stack Pressure	(in.Hg)	28.26	28.05	28.61	
Stack Temperature	(°F)	321	324	323	
Stack Flow Rate	(dscfm)	24143	25151	25201	
Percent O_2		2.3	2.3	2.2	
Percent CO_2		10.3	10.5	10.0	
Percent H_2O		18	18	17	
Total DGM Volume	(dscf)	446.460	409.997	443.703	
Percent Isokinetic		107.6	104.4	104.2	
Cyclone 4 Dp50	(microns)	2.43	2.49	2.56	
Gravimetric Data		**(mg)**			
Filterable PM		2.51	2.19	1.37	
Filterable $PM_{2.5}$		No Data	0.71	0.34	
Condensible PM $MeCl_2$ Soluble		1.53	1.69	2.23	
Condensible PM Water Soluble		21.42	31.04	23.34	
Concentrations		**(gr/dscf) @ 3% O_2**			
Filterable PM		0.00008	0.00008	0.00005	0.00007
Filterable $PM_{2.5}$		No Data	0.00003	0.00001	0.00002
Condensible PM		0.00070	0.00111	0.00079	0.00087
Direct $PM_{2.5}$		**0.00070**	**0.00114**	**0.00080**	**0.00088**
SO_4		0.00047	0.00084	0.00061	0.00064
Mass Emission Rates		**(tons/year)**			
Filterable PM		0.079	0.078	0.045	0.067
Filterable $PM_{2.5}$		0.000	0.025	0.011	0.018
Condensible PM		0.656	1.092	0.776	0.841
Direct $PM_{2.5}$		0.656	1.117	0.787	0.854
SO_4		0.441	0.825	0.603	0.623
Normalized Emissions		**(lb/10^6)**			
Filterable PM		0.00012	0.00012	0.00007	0.00010
Filterable $PM_{2.5}$		0.00000	0.00004	0.00002	0.00003
Condensible PM		0.00101	0.00162	0.00114	0.00126
Direct $PM_{2.5}$		0.00101	0.00165	0.00116	0.00128
SO_4		0.00068	0.00122	0.00089	0.00093

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Table A.3 Gravimetric Data for Method 201A Samples

		NEW Method 202 Train				OLD Method 202 Train			
Run ID		Train Blank	Run 1	Run 2	Run 3	Train Blank	Run 1	Run 2	Run 3
In-Stack Filter Weight Gain	(mg)	-0.02	-0.50	-0.81	-0.70	-0.10	-0.89	-0.91	-0.97
Blank Corrected Filter Weight	(mg)		-0.48	-0.79	-0.68		-0.79	-0.81	-0.87
Gravimetric Limit of Detection	(mg)	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
In-Stack Filter Weight Gain Reported	(mg)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cyclone 4 Rinse wt. (wet) (Acetone)	(g)	44.50	65.00	71.40	87.80	20.20	66.50	67.50	49.90
Cyclone 4 Rinse Volume	(ml)	56.3	82.3	90.4	111.1	25.6	84.2	85.4	63.2
Cyclone 4 Rinse Residue wt.(dry)	(mg)	0.95	2.67	1.74	2.11	0.68	2.58	1.55	1.08
Gravimetric Limit of Detection	(mg)	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Sample Mass Blank Correction	(mg)	0.04	0.07	0.07	0.09	0.02	0.07	0.07	0.05
Cyclone 4 Blank Corrected Mass	(mg)	0.90	2.60	1.66	2.02	0.66	2.51	1.48	1.03
Cyclone 4 Rinse Residue wt.(dry) Reported	(mg)	0.90	2.60	1.66	2.02	0.66	2.51	1.48	1.03
Cyclone 4 Exit Rinse wt. (wet) (Acetone)	(g)	33.40	59.90	75.10	51.50	17.90	0.00	59.30	30.50
Cyclone 4 Exit Rinse Volume	(ml)	42.3	75.8	95.1	65.2	22.7	0.0	75.1	38.6
Cyclone 4 Exit Rinse Residue wt.(dry)	(mg)	0.32	1.32	0.92	0.80	0.42	-0.03	0.77	0.38
Gravimetric Limit of Detection	(mg)	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Sample Mass Blank Correction	(mg)	0.03	0.06	0.08	0.05	0.02	0.00	0.06	0.03
Cyclone 4 Exit Blank Corrected Mass	(mg)	0.28	1.26	0.85	0.75	0.40	-0.03	0.71	0.34
Cyclone 4 Exit Rinse Residue wt.(dry) Reported	(mg)	0.28	1.26	0.85	0.75	0.40	0.00	0.71	0.34

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Table A.4 Gravimetric Data for Method 202 Samples

		NEW Method 202 Train				OLD Method 202 Train			
Run ID		Train Blank	Run 1	Run 2	Run 3	Train Blank	Run 1	Run 2	Run 3
Inorganic (Water Sample) wt. (wet)	(g)	548.7	2754.8	2638.9	2736.6	991.0	3013.3	2914.3	2971.1
Inorganic (Water Sample) Volume	(ml)	549.7	2759.8	2643.7	2741.5	992.8	3018.7	2919.6	2976.5
Inorganic Residue wt.(dry)	(mg)	3.87	15.74	12.84	19.09	3.99	23.97	35.89	27.60
New Method 202 Titer Volume	(ml)	0.00	13.50*	1.30	1.80	0.10	1.50	2.85	2.50
Sample Mass Correction (From Titration)[0.1N NH_4OH]	(mg)	0.00	2.30	2.21	3.07	0.17	2.55	4.85	4.26
Inorganic Residue wt.(dry) Corrected for Titration	(mg)	3.87	13.45	10.62	16.02	3.82	21.42	31.04	23.34
Gravimetric Limit of Detection	(mg)	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Inorganic Residue wt.(dry) Reported	(mg)	3.43	13.45	10.62	16.02	3.20	21.42	31.04	23.34
Organic (MeCl2 Rinse) wt. (wet)	(g)	231.80	330.60	323.70	336.90	404.90	524.60	589.40	457.60
Organic ($MeCl_2$ Rinse) Volume	(ml)	174.8	249.3	244.1	254.1	305.4	395.6	444.5	345.1
Organic Residue wt.(dry)	(mg)	2.68	2.76	2.29	7.92	1.27	1.53	1.69	2.23
Gravimetric Limit of Detection	(mg)	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Organic Residue wt.(dry) Reported	(mg)	1.96	2.76	2.29	7.92	0.59	1.53	1.69	2.23

*Sample titrated with 0.01N NH_4OH, all other samples titrated with 0.1N NH_4OH.

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Table A.5 Gravimetric Data for Reagent Field Blanks

Water Blank wt. (wet)	(g)	996.7
Water Blank Volume	(ml)	996.9
Water Blank Residue wt.(dry)	(mg)	0.41
Water Blank Residue Percent by wt.		0.00004
Water Residue Concentration (restricted to ≤ 0.0001 %)	(mg/ml)	0.00041
Hexane Blank wt. (wet)	(g)	279.9
Hexane Blank Volume	(ml)	427.5
Hexane Blank wt.(dry)	(mg)	0.10
Hexane Blank Residue Percent by wt.		0.00003
Hexane Residue Concentration (restricted to ≤ 0.0001 %)	(mg/ml)	0.0002
MeCl2 Blank wt. (wet)	(g)	577.5
$MeCl_2$ Blank Volume	(ml)	435.5
$MeCl_2$ Blank wt.(dry)	(mg)	0.19
$MeCl_2$ Blank Residue Percent by wt.		0.00003
$MeCl_2$ Residue Concentration (restricted to ≤ 0.0001 %)	(mg/ml)	0.0004
Acetone Blank wt. (wet)	(g)	385.2
Acetone Blank Volume	(ml)	487.6
Acetone Blank Container 10 wt.(dry)	(mg)	0.63
Acetone Blank Residue Percent by wt.		0.00016
Acetone Residue Concentration (restricted to ≤ 0.0001 %)	(mg/ml)	0.0008
Organic CPM Samples, Average Beaker Blank	(mg)	0.11
Organic CPM Samples, Average CPM Filter Blank	(mg)	0.43
Inorganic CPM Samples, Average Beaker Blank	(mg)	0.17
Inorganic CPM Samples, Average CPM Filter Blank	(mg)	0.05

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Table A.6 Ion Chromatography Analysis of Inorganic Method 202 Samples

INORGANIC FRACTION ANALYSIS (REHYDRATED SAMPLES)								
	NEW METHOD 202				OLD METHOD 202			
Run ID	Train Blank	Run 1	Run 2	Run 3	Train Blank	Run 1	Run 2	Run 3
Liquid Vol. (ml)	100	100	100	100	100	100	100	100
pH	6.98	2.98	3.10	2.88	5.91	3.03	2.86	2.67
Measured Concentrations (mg/L), Sample Volumes = 100 mL								
Sulfate	3.28	80.62	77.16	115.05	1.10	140.81	232.05	183.28
Nitrate	1.11	<0.25	<0.25	<0.25	0.96	<0.25	<0.25	<0.25
Chloride	2.34	<0.25	<0.25	<0.25	10.60	<0.25	<0.25	<0.25
Ammonium	<0.50	5.60	5.70	10.00	<0.50	9.30	16.60	14.70
Calcium	3.40	1.30	1.00	1.50	1.80	3.20	4.90	2.60
Sodium	2.40	4.90	4.30	5.20	4.50	8.80	11.10	8.50
Mass of Components (mg), Reported to Half MML[1]								
Sulfate	0.328	8.062	7.716	11.505	0.11	14.081	23.205	18.328
Nitrate	0.111	0.025	0.025	0.025	0.096	0.025	0.025	0.025
Chloride	0.234	0.025	0.025	0.025	1.06	0.025	0.025	0.025
Ammonium	0.05	0.56	0.57	1	0.05	0.93	1.66	1.47
Calcium	0.34	0.13	0.1	0.15	0.18	0.32	0.49	0.26
Sodium	0.24	0.49	0.43	0.52	0.45	0.88	1.11	0.85
Total Mass by IC	1.303	9.292	8.866	13.225	1.946	16.261	26.515	20.958

[1]MML – Minimum Measurement Level – minimum level at which reproducible analyses can be obtained.

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Table A.7 Quality Assurance for Ion Chromatography

	New Method 202				Old Method 202			
	(milli-moles)							
Run ID	Train Blank	Run 1	Run 2	Run 3	Train Blank	Run 1	Run 2	Run 3
Sulfate$^{(-2)}$	0.0034	0.0840	0.0804	0.1198	0.0011	0.1467	0.2417	0.1909
Nitrate$^{(-1)}$	0.0018	0.0004	0.0004	0.0004	0.0015	0.0004	0.0004	0.0004
Chloride$^{(-1)}$	0.0066	0.0007	0.0007	0.0007	0.0299	0.0007	0.0007	0.0007
Hydroxide (OH^-)	9.5E-06	9.5E-10	1.3E-09	7.6E-10	8.1E-07	1.1E-09	7.2E-10	4.7E-10
Hydronium (H^+)	1.0E-05	1.0E-01	7.9E-02	1.3E-01	1.2E-04	9.3E-02	1.4E-01	2.1E-01
Ammonium$^{(+1)}$	0.0028	0.0311	0.0317	0.0556	0.0028	0.0517	0.0922	0.0817
Calcium$^{(+2)}$	0.0085	0.0033	0.0025	0.0038	0.0045	0.0080	0.0123	0.0065
Sodium$^{(+1)}$	0.0104	0.0213	0.0187	0.0226	0.0196	0.0383	0.0483	0.0370
milli-equiv anions to cations[1]	0.50	1.03	1.20	1.11	1.07	1.48	1.60	1.11
Total milli-equivalents (all ions)	0.045	0.333	0.297	0.458	0.065	0.494	0.788	0.728

[1]A charge ratio for anions to cations of close to 1.00 indicates that the analysis was relatively accurate and accounted for the majority of ions present.

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Attachment B

AF&PA Comments on Proposed National Emission Standards for Hazardous Air Pollutants From the Pulp and Paper Industry (76 Fed. Reg. 81328, December 27, 2011), February 27, 2012

American
Forest & Paper
Association

February 27, 2012

EPA Docket Center (EPA/DC)
Environmental Protection Agency
Mailcode 2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460

RE: Docket ID No. EPA–HQ–OAR–2007-0544, National Emission Standards for Hazardous Air Pollutants From the Pulp and Paper Industry (76 *Federal Register* 81328, December 27, 2011)

The American Forest & Paper Association ("AF&PA") appreciates the opportunity to submit comments on the Proposed National Emission Standards for Hazardous Air Pollutants From the Pulp and Paper Industry (76 Fed. Reg. 81328, December 27, 2011). The American Forest & Paper Association is the national trade association of the forest products industry, representing pulp, paper, packaging and wood products manufacturers, and forest landowners. Our companies make products essential for everyday life from renewable and recyclable resources that sustain the environment. The forest products industry accounts for approximately 5 percent of the total U.S. manufacturing GDP. Industry companies produce about $175 billion in products annually and employ nearly 900,000 men and women, exceeding employment levels in the automotive, chemicals and plastics industries. The industry meets a payroll of approximately $50 billion annually and is among the top 10 manufacturing sector employers in 47 states.

The forest products industry is a leader in sustainability and a foundation for green jobs. We supply family-wage jobs, lead the way on recycling and renewable energy, sustainably use renewable resources, and reduce greenhouse gases by using carbon-neutral energy and sequestering CO_2. Unfortunately, these important contributions are challenged by an unprecedented wave of new regulatory proposals under the Clean Air Act, including updates to the Pulp and Paper NEHSAP that could cause severe unintended harms if not carefully designed. This challenge comes right after the worst economic crisis since the Great Depression. To address this challenge, we stand ready

1111 Nineteenth Street, NW, Suite 800 ▪ Washington, DC 20036 ▪ 202 463-2700 Fax: 202 463-2785 ▪ www.afandpa.org

BETTER PRACTICES
BETTER PLANET 2020
Continuing AF&PA's Commitment to Sustainability

to work with EPA, the Administration, and other stakeholders to achieve a regulatory path for a sustainable future.

Thank you for your consideration of the important issues included in these comments. Please feel free to contact Tim Hunt at 202-463-2588 on my staff if you have questions or need more information.

Sincerely,

Paul Noe
Vice President for Public Policy
American Forest & Paper Association

cc: G. McCarthy
J. Goffman
P. Tsirigotis
R. Dunkins
J. Bradfield
B. Schrock

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Attachments

Attachment 1: Review of the HEM3 Modeling Conducted by EPA for the Pulp & Paper Industry RTR by David Heinold, AECOM (February 2012)

Attachment 2: Comments from the Formaldehyde Panel of the American Chemistry Council in Response to EPA's Proposed NESHAP from the Pulp and Paper Industry February 27, 2012, (Docket No. EPA-HQ-OAR-2007-0544.)

Attachment 3: *Hexachloroethane Emissions from Brownstock Washers and Bleach Plant Source*, Zach Emerson, NCASI, February 24, 2012

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Attachment 4: *Interim comments on rationale and methodologies used to evaluate and propose increased treatment requirements for kraft condensates in the Pulp and Paper ITR* NCASI Memo to Ms. Robin Dunkins, Mr. John Bradfield, Mr. Bill Schrock, February 18, 2012.

Attachment 5: AF&PA Estimated Cost Impacts of Proposed Rules

Attachment 6: Example Compliance Option for the Clean Condensate Alternative (CCA)

Attachment 7: *Establishing Periods for Condensate HAP Collection*, Ashok K. Jain, NCASI

I. Introduction

The results of the Risk and Technology Review by EPA for the Pulp and Paper NESHAP determined that the level of residual risk that remains for the Subpart S category is acceptable. In short, the Maximum Achievable Control Technology (MACT) requirements were successfully implemented and the resulting reductions in emissions ensured that health risks associated with these facilities were protective with an ample margin of safety. This success was due to the efforts of both the Agency and the Industry to develop rules based on sound science with flexible compliance alternatives to allow for the unique situations at each facility. As described in detail below, AF&PA and its members are committed to operating in an environmentally responsible and sustainable manner. However, the U.S. forest products industry faces serious challenges to recover from the economic downturn and to overcome fierce competition from overseas manufacturers. In the face of such extreme economic pressure, the proposed rules would make matters far worse by imposing hundreds of millions of dollars of additional costs when the analysis shows the remaining amount of residual risk does not warrant such action. Therefore, it is imperative that any revised standards be carefully designed such that health and the environment continue to be protected without requiring unnecessary expenditures of resources and time.

As described in detail in these comments, EPA has the legal discretion and technical justification to substantially reduce or eliminate the burden of the proposed modifications to the Subpart S standards while still providing ample protection to health and the environment. EPA has ample discretion to make pragmatic choices that would appropriately balance EPA's responsibility to protect health and the environment with the Agency's (and the US Government's) need to protect and promote the productive capacity of the Nation.

II. Executive Summary

AF&PA, NCASI and the paper industry have a long history of working with EPA on air toxic regulations. The Subpart S rule was part of a multi-phase, multi-pollutant "Cluster" rule that integrated waste water Effluent Guideline rule revisions and air NESHAP rules and was heralded by EPA as a cooperative effort with industry and other public parties. Development of the rule took nearly a decade of ardent work and stakeholder/EPA joint problem-solving. For example, industry provided extensive test data and information at great expense that formed the basis for the Subpart S and Subpart MM MACT rules. Given the complexity and diversity of pulp and paper mills, the rules provide several alternative compliance options that have been widely used, cost effective and resulted in phases of pollution control equipment construction and integrated compliance strategies in the last decade.

Similarly, the industry has been very engaged with EPA when the Agency started to consider its residual risk and technology reviews for pulp and paper mills. Companies provided several iterations of improvements to the National Emissions Inventory and responded to a very extensive Information Collection Request (ICR) in 2011 even though AF&PA cautioned EPA that this was not the best way to collect information to inform its decision making. While we continued to seek information on the risk modeling results, AF&PA never heard how the ICR data was being used in the technology review, so it came as a surprise when the proposal included an increase in condensate treatment efficiency, an unexplained increase in the widely used pound-per-ton removal option beyond what the increased condensate treatment efficiency would imply, and a suggestion that EPA might simply eliminate excess emission allowances that are part of the current MACT standard In addition, AF&PA discussed the importance of the current excess emission allowances with EPA staff at several junctures in the rule development process so again it was unexpected that the Agency was considering their elimination. We understand that EPA is under a court-ordered deadline for this RTR, but that should not prevent meaningful information exchanges between EPA and the industry before a proposal is issued on a very complex data set. In fact, we warned the court that an accelerated rulemaking schedule could jeopardize a well-supported rule. The result is the proposed rule requires an increase in control efficiency that is not properly documented or justified in the docket.

AF&PA has used its best efforts to prepare useful comments in the time that EPA has provided. AF&PA has been hampered in its efforts by the lack of explanation in the preamble to the proposed rule and in the docket for how EPA analyzed available data and how EPA derived proposed revised standards and estimated costs and pollutant reductions. The specific model EPA used in its risk assessment is not available to the public. In some cases, as explained below, we have had to speculate about what EPA intended and respond on that basis. For those reasons, there may be comments here that EPA does not understand, or there may be aspects of EPA's intended proposal that AF&PA did not understand. We hope that there will be opportunities for clarification as EPA reviews these comments. In a number of instances, however, if EPA wishes to change the existing Subpart S standards EPA will have to publish a new proposed rule, because the December 27, 2011 notice either lacks a specific proposal at all or is so vague or ambiguous as to deprive the public of a meaningful opportunity to comment. As the courts have made clear, the fact that EPA has entered into an agreement to promulgate a final rule by July 31, 2012 would not excuse EPA from meeting its full procedural obligations, including: providing a clear explanation of the basis for proposed rule changes, providing the full set of data upon which to support any proposed rule revisions, and sufficient time for notice and comment. See, e.g., *U.S. Steel Corp. v. U.S. EPA*, 595 F.2d 207, 213 (5th Cir. 1979).

A. We Support the Conclusion that the Current Standard Protects Public Health with an Ample Margin of Safety

We support EPA's conclusion that the current MACT standards protect human health with an ample margin of safety. This is no accident as the industry spent roughly $1 billion in capital to control air emissions from pulp and paper mills to meet the Subpart S requirements. In fact, we believe the estimated acceptable risks are overstated due to use of conservative health benchmarks, inappropriate modeling assumptions and over estimates of emissions. EPA is required to look at both individual and population risks, and the conclusion that there is only about one statistical cancer case every 100 years shows emissions are well controlled. The conclusion of the section 112(f) risk review that no further controls are needed is well founded.

B. EPA's Technology Review Is Flawed

Unfortunately, we cannot indicate the same support for the "technology review" EPA performed under section 112(d)(6), even though EPA appropriately concluded there have been no advances in emission control measures. AF&PA strenuously objects to the apparent conclusion that current condensate treatment technologies should be required to perform at a higher level than the 92% control requirement established as the MACT "floor" in the Subpart S rule promulgated in 1998. First, EPA has misinterpreted the data upon which it has relied, due in part to the complexities of the compliance options allowed under Subpart S. Control efficiencies of steam strippers and biological treatment systems have not changed since implementation of Subpart S. EPA did not justify the basis for these changes, why they are necessary, and how they expect facilities to comply. This lack of information and clear explanation do not give AF&PA adequate opportunity to comment.

Second, the derivation of numerical limits corresponding to the 94% condensate control requirement, for mills using the lb/ODTP option, is flawed as it would require the collection of additional condensates which EPA did not intend (nor include in its cost estimate). The control efficiency increase would be closer to 25% than 2%. As a result, previously established compliance options would no longer be feasible, and very large investments would be necessary for compliance for no identified risk-reduction benefit, if compliance with this higher standard was even achievable by all mills. Finally, EPA has significantly under- estimated the cost of its proposed increase in condensate control , further validating that this change is not the small 2% control efficiency adjustment that EPA intended. AF&PA estimates the capital costs as being 9 to 23 times higher than EPA has estimated. EPA must consider costs and benefits under Clean Air Act section 112(d)(6) and Executive Order 13563, and spending $38,000 or more per ton for largely methanol reductions is a bad investment, and, more

importantly, it is not required by, nor consistent with the Clean Air Act because no risk remains as a result of the current condensate treatment requirements.

C. Venting and Stripper Downtime Excess Emission Provisions Must Be Retained

The current excess emission provisions were established as part of the MACT "floor" and must be retained. The provisions are necessary for the safe operation of any pulp and paper mill and largely are not associated with equipment malfunctions. Any efforts to reexamine these provisions should happen outside the process of the residual risk and technology reviews because (1) EPA has not provided industry enough time to respond to its many questions regarding the need for these provisions, (2) the circumstances of their need and use are complex and unique to this source category, and (3) EPA is on an accelerated rulemaking schedule which will be a challenge to meet for just the section 112(f) and 112(d)(6) issues and will not provide time for a careful examination of excess emission provisions. We provide initial comments on excess emission provisions now and plan on supplementing these comments with additional information and suggestions by June 27, 2012, as EPA recently authorized.

Once industry provides EPA this additional data, we strongly urge that EPA and industry meet to review and discuss the information, since excess emission events are varied and their origins diverse. An understanding of current venting situations is essential to any meaningful review or consideration of changes to these well-established practices.

D. EPA Should Continue To Apply Different Requirements for Startup, Shutdown, and Malfunction Periods

EPA's proposal to require sources to meet the same emission limitations during periods of startup, shutdown, and malfunction represents an unauthorized change to existing MACT standards. It is not required by case law and is inconsistent with past EPA practice and judicial interpretations of NESHAPs and NSPS. With respect to both SSM provisions and the excess emission provisions discussed above, EPA pins its analysis on semantic distinctions around the term "malfunction," a term not even used in the relevant statutory authorities. The proposal lacks any meaningful assessment of the effect of startup and shutdown events on mills' ability to comply with the numerical emission limitations in the rule, nor of the cost to eliminate the current allowances for startup and shutdown. There is no indication that EPA even considered using its authority under CAA section 112(h) to set work practice standards in lieu of the numerical emission limitations, even though EPA acknowledges the difficulty of sampling or monitoring emissions during such events. The affirmative defense EPA

offers for claims for civil penalties for certain types of malfunctions is not a legally sufficient alternative to establishing section 112-compliant standards in the first place, and in any event it is impracticable in numerous respects.

E. EPA Has Underestimated the Cost To Implement Proposed Rule Changes

In sum, Subpart S has been a success in reducing health risks and requiring installation of the best control technologies, so no changes in the current regulatory requirements are warranted especially given the potential costs. The proposed changes, plus elimination of the excess emission provisions, could cost industry conservatively at least $2.4 billion in capital – 67 times greater than the $36 million in capital EPA estimated for the proposal. The table below summarizes the cost for each of the major provisions, each of which is substantial on its own.

Table 1: Capital Cost Impact of Proposed and Potential Rule Changes

Provision	EPA Cost Estimate	AF&PA Cost Estimate
94% control efficiency	$36 M	$300 M
Over-collection	NA	$500 M
Elimination of Excess Emission Provisions	NA	$1,600 M
Total	$36 M	$2.4 B

III. Risk Analysis

EPA has applied suitable modeling tools for the RTR assessment and the use of the ICR data has improved the accuracy of dispersion modeling and risk estimates. However, limitations and errors in the input data and in the modeling methods used, such as noted below, still affect the ability of the RTR assessment to accurately characterize maximum off-site risk. In most cases it is expected that a more accurate and detailed characterization of emissions sources would result in lower, more realistic risk estimates. AF&PA's ability to independently verify EPA's modeling, and to assess the effects of improving some of the input data as described below, is limited because the risk assessment platform used by EPA is not in the public domain and has not been made available by EPA.

A. We Support the Conclusion that the Current Standard Protects Public Health with an Ample Margin of Safety

In the preamble to the proposed rule, EPA states "we conclude that the current standard, before the amendments proposed here are put in place, protects public health with an ample margin of safety" (See 76 Fed. Reg. 81344). AF&PA supports this statement. The modeled risk results are based on data supplied by 171 mills during the Information Collection Request (ICR) in 2011. The data collected comprise a comprehensive data set reflecting the most up-to-date information. We estimate that the industry spent over $5 million to respond to the ICR survey (not including the cost for the original collection of the data that were included in the survey).

The results of the analysis conducted by EPA show that the NESHAP Subpart S rule was successful; in other words, MACT worked. This success is due to many factors, including approximately $1.0 billion[1] dollars spent by the industry to achieve the emission reductions realized by the rule.

B. Risk Result Corrections

Although the analysis conducted by EPA showed the current standard protects public health with an ample margin of safety, AF&PA worked with NCASI, consultants, and industry members to understand the risk drivers for the facilities with the highest risk as modeled by EPA. In the RTR risk assessment EPA incorporated information provided by mills in response to the recent ICR. A detailed examination of the modeling data used by EPA for mills with higher modeled risk identified some of the same issues previously encountered by AF&PA and discussed with EPA during the review of National Emissions Inventory (NEI) data.

AF&PA's consultant, AECOM, found errors in the model input parameters among the mills with higher modeled risk.[2] It is expected that these types of errors are common among all of the mills and <u>thereby likely contribute to a general overestimation of modeled risk</u> from this industrial sector.

- In EPA's refined assessment of the acute risk of Subpart S sources, eleven HAPs and nine mills had modeled maximum acute Hazard Quotients of 1.5 and greater. Among these mills more than one-third (4 of 9) have impacts that are

[1] NCASI estimate for implementation of Subpart S and Subpart MM. Majority of the capital cost was for Subpart S.

[2] See Attachment 1, Review of HEM Modeling Conducted by EPA for the Pulp and Paper Industry RTR, AECOM, February 2012

dominated by modeled wastewater treatment area sources that are incorrectly located.

- In EPA's assessment of the potential health effects due to long-term inhalation exposure from Subpart S sources, 42 mills had a modeled maximum individual lifetime cancer risk of 2 chances in a million or greater. Predicted hazard indices for all mills were less than 1 for Subpart S sources. For the 42 mills , the following observations can be made:

    - Risks at more than 64 % of these mills (27 of 42) are primarily associated with emissions from mill sources characterized as area sources, simplistically representing a large number of discrete emission sources. In dispersion modeling it is commonly found that a more detailed source characterization materially reduces modeled concentrations and associated modeled maximum off-site risk. This is largely because modeling as area sources inherently assumes that all emissions in the area are released at a single height and no credit is given for plume rise associated with individual point sources.

    - About 17% of the mills (7 of 42) were characterized as single point emission sources or with consolidated releases emitted from only a few points. This simplistic method insufficiently characterized the spatial distribution of source emissions at the mill, and would be expected to result in overestimates of off-site concentrations and associated risk.

    - About 26% of the mills (11 of 42) had incorrectly located one or more of the sources that contributed substantially to the modeled risk. It is expected that more accurately locating these sources would result in lower modeled risk.

    - Three of the 42 mills had maximum modeled risk at a population-based receptor that was erroneously placed in an uninhabited and inaccessible location close to a major emissions source.

    - About 26% of the mills (11 of 42) had erroneously calculated emissions, input the total facility emissions for a category into multiple sources rather than the contribution of each source, or used an emission factor based on questionable data. It is expected that more accurately locating these sources would result in lower modeled risk.

    - About 19% of the mills (8 of 42) had characterized sources with very low or default fugitive release heights. This simplistic method insufficiently characterized the dispersion of these source emissions at the mill, and

would be expected to result in overestimates of off-site concentrations and associated risk.

In addition, for several mills the input data utilized in EPA's risk assessment were incorrect and those mills intend to submit corrected or updated data to EPA. Examples of data corrections include the following:

- HEM input data were off several orders of magnitude due to either mistakes in the NEI submittals or transcription errors from the NEI to the HEM model
- Some facilities did not submit an updated NEI to EPA based on revised bleached paper machine emission factor data issued by NCASI[3] in late June 2011
- Unrepresentative meteorological data were used in the HEM assessment

Based on findings highlighted above and discussions with facility personnel, we expect that the HEM risk results reported by EPA are in general higher than the actual risk for the industry that would be modeled if appropriate modeling refinements and corrections were made. However, even with these errors, EPA has determined that the remaining residual risk levels are acceptable. We realize that, in light of that conclusion, EPA may decide it is not necessary to rerun the HEM model and update the risk assessment at this time. We wish to note, however, that the correction of the identified errors would result in a lower estimated risks for pulp and paper mills at current emission rates.

C. Comments on Methodology

1. HEM3 Model & Corresponding Data Sets Are Not in the Public Domain

The inhalation risk estimates for this sector have been computed using EPA's Human Exposure Model (HEM3-AERMOD). For this assessment EPA updated the public domain version of HEM3 (available at http://www.epa.gov/ttn/fera/hem_download.html) so that the program implements the current version of AERMOD. In applying HEM3, EPA applied a more robust set of hourly meteorological data than the data available on the HEM3 Website. In addition, EPA revised the population-based receptor files in HEM3 to exclude receptors that appear to be on-site and to add receptors in nearby residential areas. While these types of modeling enhancements are suitably

[3] The National Council for Air and Stream Improvement (NCASI) is an independent, non-profit research institute that focuses on environmental topics of interest to the forest products industry.

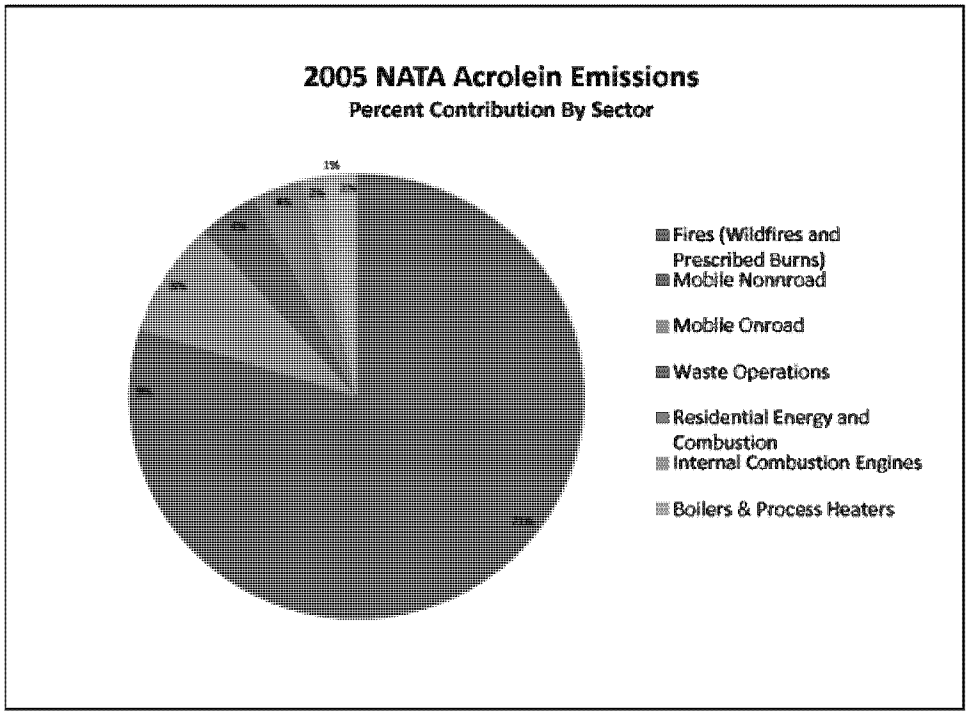
incorporated into the RTR, EPA's use of a version of HEM3 and corresponding receptor and meteorological data sets that are not in the public domain prevents us from independently verifying and interpreting EPA's risk findings. Although, upon our request, EPA has shared detailed HEM3 output, the unavailability of the updated program and data has prevented a more in-depth and comprehensive review and examination of the effects of correcting model inputs in terms of modeled risks.

2. Acrolein Emissions

EPA "removed acrolein emissions from the Subpart S modeling files due to the uncertainty in the emissions estimates" (See 76 Fed. Reg. 81334).[4] We concur with EPA's conclusion that the available acrolein emissions information is not reliable and can not serve as the basis for a determination that there is unacceptable residual risk from existing pulp and paper mill HAP emissions. For starters, acrolein is a very reactive gas and hard to measure at the parts per billion level of emissions. Acrolein acute toxicity is also not a concern. Please be reminded that AF&PA submitted information to EPA in January 2011 pointing out faults in the acute toxicity values. The primary generators of acrolein emissions are fires and mobile sources; however, EPA has not regulated acrolein from mobile sources to date. The forest products industry is a very small contributor to ambient levels/loadings of acrolein because paper mill acrolein emissions would only be a fraction of the 1% shown for boilers and process heaters (See Figure 1).

[4] EPA's contractor RTI elaborated on the causes of this uncertainty in Appendix H of the memorandum entitled, "Inputs to the Pulp and Paper Industry October 2011 Residual Risk Modeling," located in the docket at EPA-HQ-OAR-2007-0544-0122. RTI explained that "in the case of acrolein from Subpart S non-combustion sources, this [EPA emission factor development] protocol results in emission factors based primarily on assumed ½-MDL values from a majority of test runs where acrolein was not detected which introduced a large number of unknowns into the dataset, thereby multiplying the uncertainties [in the source of acrolein emissions from non-combustion sources] outlined above to an unknown degree. The uncertainty in the initial data set is further magnified when the emission factors are applied across the industry, yielding a resultant acrolein emission inventory predicated primarily on assumed values and not actual emissions measurements. This magnified uncertainty is compounded with the additional uncertainty of acrolein emissions from different paper machine operating parameters and different wood species used in pulping, resulting in further exacerbation of the uncertainty." Inputs Memo p. H-2.

Figure 1: 2005 NATA Acrolein Emissions



In the past, paper machines have been identified by EPA as the primary source of acrolein emissions from pulp and paper mills. However, emissions levels of acrolein from paper machines are very low – low enough that accurate testing is limited by the test method.

In addition to the uncertainty in the magnitude of emissions from the paper industry, the health effects caused by exposure to acrolein are certainly overestimated in EPA's IRIS database. In 2007 the Hamner Institute completed a study of acrolein's health effects which included 90-day animal/rat studies as well as work on a computational fluid dynamic model (CFD) on uptake of acrolein to understand biological dose. This research was published in a peer-reviewed journal.[5] On October 17, 2008, AF&PA sent a letter advising EPA of the new studies and in December 2010 AF&PA asked EPA to update its acrolein IRIS assessment and amend the risk value for acrolein using the

[5] Dorman, et al., Respiratory Tract Responses in Male Rats Following Subchronic Acrolein Inhalation, *Inhalation Toxicology* 20:205-216 (2008). Schroeter et al., Application of Physiological Computational Fluid Dynamics Models to Predict Interspecies Nasal Dosimetry of Inhaled Acrolein, *Inhalation Toxicology* 20:227-243 (2008). Struve, et al., Nasal Uptake of Inhaled Acrolein in Rats, *Inhalation Toxicology* 20:217-225 (2008).

Hamner studies. Before EPA estimates any risk from acrolein emissions, the IRIS assessment on acrolein must be revised to reflect the best available science.

In February 2010, EPA's Science Advisory Board (SAB) supported the use of IRIS as the "preferred" database but also advised EPA to consider alternatives where the IRIS values are based on limited data. Specifically, "the Panel found EPA's approach to selecting dose-response chronic toxicity values to be generally sound, but recommends the Agency more closely scrutinize values that emerge as drivers of risk assessment results." [5/7/10 letter to EPA]. The table below shows a comparison of the acrolein Reference Concentrations (RfC) used by government organizations for risk analysis. Table 2 shows that EPA's current value for acrolein is, indeed, not based on the best available scientific data and more than 15 times more stringent than the RfCs established more recently by CalEPA and Ontario.

Table 2: Comparison of Acrolein RfC used by Various Government Organizations

Government Agency	Previous RfC ($\mu g/m^3$)	Recent RfC ($\mu g/m^3$)	Year
EPA	0.02	0.02	2003
Hamner Institute	--	0.6	2008
CalEPA	0.06	0.35	2008
Ontario	0.08	0.4	2009

EPA's current RfC is based on a study by Feron (1978) that examined few animals, did not involve exposure concentrations low enough to develop a NOAEL (no observed adverse effect level) (just LOAEL), and did not study nasal uptake/activity. EPA has acknowledged the study was of poor quality and large uncertainty factors were used (1000x). EPA noted the following in a technical document regarding the use of health effects information in evaluating school air toxic monitoring results

> "The comparison level shown for acrolein is the EPA RfC which is set below a level associated with health effects. The RfC is set as a factor of 1000 below an exposure concentration associated with sensitive nasal effects in laboratory animals. Since the EPA RfC was derived, the California EPA has derived a

chronic REL[6] based on more recently available information on acrolein and its effects. The Cal-EPA REL, which is 0.35 $\mu g/m^3$, is somewhat more than a factor of 100 below the level associated with effects in the more recently available study."[7]

The recommended value, based on the Hamner Institute study, is 30 times less stringent than what EPA is using (0.6 $\mu g/m^3$ (270 ppt) vs. 0.02 $\mu g/m^3$ (9 ppt)). CalEPA (0.35 $\mu g/m^3$) and Ontario, Canada (0.4 $\mu g/m^3$) have set their RfCs at much less stringent levels. The values used by CalEPA and Ontario are referenced by EPA as more appropriate in the technical document for interpretation of health effects surrounding schools.

In sum, we support EPA's proposed conclusion that the available acrolein emission information is not reliable and cannot be used for regulatory purposes. But, even if EPA were to include acrolein emissions in its risk assessment for this source category, the alternative RfCs presented in the Hamner study would be more scientifically valid than the EPA IRIS value. When both the Hamner study RfC and industry emissions data for acrolein are applied, the analysis would not support a conclusion that there are any significant residual risks associated with acrolein emissions from this source category.

3. Formaldehyde Emissions

As noted in the comments from the Formaldehyde Panel of the American Chemistry Council in Response to EPA's Proposed NESHAP from the Pulp and Paper Industry "the EPA has failed to support key conclusions . . . with the best available science"[8] in evaluating the potential impacts from formaldehyde emissions. "In particular, EPA incorporates the 1991 IRIS dose-response model – an overly conservative and outdated model – for determining the level of risk presented by formaldehyde exposure and ignored, without any rationale, nearly 25 years of research. The utilization of the IRIS model is all the more egregious considering the availability of the CIIT biologically-

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[6] REL refers to a Reference Exposure Level. "CalEPA defines the REL as a concentration level at (or below) which no health effects are anticipated, a concept that is substantially similar to EPA's non-cancer dose-response assessment perspective." http://www.epa.gov/ttn/atw/toxsource/chronicsources.html

[7] Schools Air Toxic Monitoring Activity (2009) Uses of Health Effects Information in Evaluating Sample Results, 09/10/2009, EPA, http://www.epa.gov/schoolair/pdfs/UsesOfHealthEffectsInfoinEvalSampleResults.pdf

[8] Comments from the Formaldehyde Panel of the American Chemistry Council in Response to EPA's Proposed NESHAP from Pulp and Paper Industry (Docket No. EPA-HQ-OAR-2007-0544.); 2/27/12

based dose-response (BBDR) model, which better reflects the available science."[9] The Formaldehyde Panel also points out that in the National Academy of Sciences' (NAS) April 2011 report of its review of formaldehyde risk, the panel supported the use of the CIIT BBDR model and concluded that "the BBDR model for formaldehyde is one of the best–developed BBDR models to date" and recommended that "EPA use the BBDR model for formaldehyde in its cancer assessment."[10] Further, EPA relies on an inferior model to support its impact analysis of formaldehyde emissions from pulp and paper mills.

AF&PA urges EPA to reject the 1991 IRIS dose-response model in evaluating formaldehyde risk. Key deficiencies in the use of data in the risk analysis include:

- Contrary to IQA Guidelines, EPA inappropriately applies the outdated IRIS dose response values in determining formaldehyde inhalation exposure risk in support of the Proposed Rule.
    - The 1991 IRIS model does not constitute the best available science and therefore should not be used in determining formaldehyde inhalation exposure risk in support of the Proposed Rule.
        - The CIIT's BBDR model is a superior model for determining the cancer risk associated with formaldehyde exposure.
        - EPA overstates the variability associated with CIIT's model and bases its view on inappropriate manipulations of the model's underlying assumptions.
        - The deference given to the 1991 IRIS Assessment is directly at odds with EPA's mandate to "consider all credible and relevant information" in a rulemaking proceeding.
        - EPA's proposed rule should be based on the best available science at the time of the rulemaking." [11]

4. Hexachloroethane (HCE)

Hexachloroethane (HCE) emissions from brownstock washers and bleach plant sources emerged as a primary risk driver for some facilities in EPA's December 2011 risk modeling. Many facilities used emission factors found in NCASI's Air Toxics

[9] Id.

[10] National Research Council of the National Academies, *Review of the Environmental Protection Agency's Draft IRIS Assessment of Formaldehyde* (2011) (NAS Report), available at http://www.nap.edu/catalog.php?record_id=13142.

[11] Comments from the Formaldehyde Panel of the American Chemistry Council in Response to EPA's Proposed NESHAP from Pulp and Paper Industry, Attachment 2 .

Database to estimate HCE emissions from these sources. These NCASI emission factors are based upon limited test data from 1993, most of which were non-detects. HCE was detected in one diffusion washer vent at a bleached pulp mill and not detected at three vacuum-drum washer systems (eleven total vents) at two bleached pulp mills. HCE emissions were detected in one ECF bleach plant scrubber vent but not detected in six non-ECF bleach plant systems. HCE is not a known pulping byproduct, and the conditions for its formation are not expected to exist either in brownstock washer systems or in bleach plant systems. Given the above factors, there is significant uncertainty about these isolated detects in the brownstock washer and bleach plant sources. NCASI is planning to perform additional emissions testing of several vents from a vacuum drum washer system, a diffusion washer system, and a bleach plant scrubber to confirm the expected absence of hexachloroethane. A memo from NCASI outlining this issue is included as Attachment 3[12].

D. EPA's Approach to Examining Risk is Inconsistent with the Statute

1. EPA Fails To Provide a Rational Basis for Using Allowable Emissions in Conducting Risk Assessments Under § 112(f).

EPA uses the term "MACT allowable" emissions in the preamble to mean "the highest emissions level that could be emitted by the facility without violating the MACT standards" (See 76 Fed. Reg. at 81334). The Agency asserts that considering MACT allowable emissions in determining residual risk under § 112(f) "is inherently reasonable since these risks reflect the maximum level at which sources could emit while still complying with the MACT standards." *Id.* The Agency's risk assessment included an assessment at "MACT allowable" emissions levels. Specifically, the Agency used actual emissions from the data supplied in the Part II NEI emissions dataset and developed a ratio to calculate MACT allowable emissions based on control levels reported in the ICR for each facility. Risk estimates were then based on these calculated MACT allowable emissions.

EPA cannot lawfully use MACT allowable emissions in the proposed risk assessments and residual risk determinations because the Agency has failed to provide any reasoned explanation for why risk assessments based on actual emissions estimates are inadequate. It is noteworthy that CAA section 112(f)(1)(A) required EPA to report to Congress on "methods of calculating the risk to public health *remaining, or likely to remain*, from sources subject to regulation under this section after the application of

[12] "Hexachloroethane Emissions from Brownstock Washers and Bleach Plant Sources", Zach Emerson, NCASI, February 24, 2012

standards under subsection (d) of this section" (emphasis added). Section 112(f)(1)(B) required EPA also to report on "the *actual health effects* with respect to persons living in the vicinity of" affected sources" (emphasis added). These requirements clearly signal that Congress expected EPA to focus on actual risk and not hypothetical risk in implementing the requirements of section 112(f). Thus, it is not reasonable in the first instance for EPA to construe section 112(f) as authorizing Agency risk assessments based on hypothetical "MACT allowable" emissions.

Moreover, the Agency's risk assessment methodology already reflects numerous conservative assumptions. For example, health benchmarks, such as acute reference doses, typically incorporate two to three orders of magnitude of conservatism to account for uncertainties, such as the extrapolation of animal toxicity testing data to humans. Similarly, the dispersion models used to predict off-site ambient HAP concentrations attributable to emissions from affected sources incorporate numerous conservative assumptions to simplify the analysis of highly complex factors, such as meteorology, terrain, and atmospheric chemistry. In addition, risk assessments assume exposure to the most exposed individual on a continuous basis for an entire lifetime.

In light of the conservatism that already is inherent in EPA's risk assessment methodology, it makes no sense to apply yet another layer of conservatism – this time based on the hypothetical assumption that affected sources should be expected to emit more than the actual data indicate – to section 112(f) risk assessments. Furthermore, EPA has provided no data or analyses indicating that its current methodology results in negative bias. EPA has provided no data demonstrating that affected sources actually do emit at levels significantly higher than the actual data show for any significant period of time, or should reasonably be expected to do so.[13] In short, EPA's proposal to use hypothetical emissions levels in section 112(f) risk assessments is based on nothing more than the unsupported assertion that sources *might* emit at these higher levels. The failure to provide a reasoned explanation or evidence as to why this approach is justified and the failure to provide any record evidence supporting the use of MACT allowable emissions render this proposal insupportable under the law.

2. The "Total Facility" Approach to Conducting Risk Assessment Exceeds EPA's Authority Under § 112(f).

EPA explains in the proposal that, "To put the source category risks in context, we also examine the risks from the entire "facility," where the facility includes all HAP-emitting

[13] To the contrary, as explained below mills necessarily design and operate their emission control systems to operate at emission rates below the applicable standards, to provide a compliance margin that accommodates variability in process and control equipment.

operations within a contiguous area and under common control" (See 76 Fed. Reg. 81338). For this source category, EPA concludes that, "Nearly all 171 major sources include chemical recovery combustion sources (e.g., recovery furnace, smelt dissolving tank, lime kiln)" and that, "Pulp and paper mills also include paper coating, landfills, petroleum storage and transfer and other operations." *Id.* As a result, "where data were available, we performed a facility-wide risk assessment for these major sources as part of today's action." *Id.*

Notwithstanding these assertions, EPA is without authority to consider facility-wide risks because the CAA requires residual risk determinations to be conducted on a category-by-category basis. Section 112(f)(2)(A) unambiguously requires EPA, within 8 years after adopting a MACT standard for a given source category or subcategory, to "promulgate standards for such category or subcategory if promulgation of such standards is required in order to provide an ample margin of safety to protect public health." Section 112(f)(2)(A) further dictates that, "Emissions standards promulgated under this subsection shall provide an ample margin of safety to protect public health." It is not reasonable to construe these provisions as authorizing EPA to consider emissions from entire facilities in conducting risk assessments and potentially revising the underlying rule, for the simple reason that the Congress clearly envisioned that full implementation of the MACT program would take longer than 8 years. Consequently, it would be impossible for EPA to fulfill its unambiguous obligation for section 112(f) standards to protect public health with an ample margin of safety in cases where facilities contain sources in a category where the 8-year deadline for conducting the section 112(f) risk review precedes the adoption of MACT standards for other sources at the facilities.

In addition, section 112(f)(2)(A) further provides that, "If standards promulgated pursuant to subsection (d) of this section and applicable to a category or subcategory of sources emitting a pollutant (or pollutants) classified as a known, probable or possible human carcinogen do not reduce lifetime excess cancer risks to the individual most exposed to *emissions from a source in the category or subcategory* to less than one in one million, the Administrator shall promulgate standards under this subsection for such source category" (emphasis added). This provision unambiguously requires the section 112(f) risk assessment to be focused exclusively on "emissions from a source in the category or subcategory." For this reason alone, EPA does not have authority to consider emissions from any sources other than those in the source category or subcategory under review at that time. Thus, the risk assessment EPA conducted for the proposed rule overstates the risks that EPA was supposed to be considering in the residual risk review for Subpart S.

3. Demographics May Not Be Considered in Conducting Risk Assessments Under § 112(f).

EPA explains in the preamble that "the agency has reviewed this rule to determine if there is an overrepresentation of minority, low income, or indigenous populations near the sources such that they may face disproportionate exposure from pollutants that could be mitigated by this rulemaking" (See 76 Fed. Reg. at 81353). EPA concludes that the rule will not have such effects because "it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority, low income, or indigenous populations." *Id.*

EPA is without authority to factor such "environmental justice" considerations into this rule, because the term "public health" cannot reasonably be interpreted to include consideration of environmental justice in the section 112(f) context. Section 112(f)(2)(A) expressly instructs EPA to impose additional emissions controls if needed to provide an ample margin of safety "to protect public health." The term "public health" is not defined in section 112 or in EPA's Part 63 regulations.

In the context of EPA's national ambient air quality program ("NAAQS"), the Supreme Court has observed that the "primary definition of the term" should be applied – *i.e.*, public health means "the health of the public." *Whitman v. American Trucking Associations, Inc.*, 531 U.S. 457, 465 (2001). This conclusion emphasizes that the scope of the term "public health" should be dictated by the meaning of the word "public." In relevant part, Webster's Dictionary defines the adjective "public" to mean "of, relating to, or affecting all of the people or the whole area of a nation or state" and "of or relating to people in general." These definitions emphasize that the word "public" should be construed expansively as describing the people as a whole, and not particular demographic segments.

EPA's established approach to assessing potential impacts on public health under the NAAQS program is consistent with this meaning. EPA reasonably interprets the term "public health" to include consideration not only of potential impacts to the population as a whole, but also to sensitive subpopulations – recognizing that the objective is to protect the group rather than any particular individual in the group (See, e.g., 71 Fed. Reg., 61144, 61145 fn. 2 (Oct. 17, 2006)). Importantly, sensitive subpopulations are identified according to their particular health-based sensitivities (*e.g.*, asthmatics) rather than demographic classifications unrelated to particular health-based sensitivities (*e.g.*, population without a high school diploma).

With this backdrop, it would not be reasonable to construe the term "public health" as used in section 112(f) as allowing consideration of demographic classifications that

bear no relationship to the potential health effects presented by the HAPs at issue for the given source category or subcategory. EPA's proposal would unreasonably inject racial, ethnic, economic, and other policy considerations into a program designed to provide protection for the public at large. For example, if EPA were to suggest that the population without a high school diploma should receive extra scrutiny, why should the Agency not afford the same scrutiny to other reasonably definable educational groups, such as those with a high school diploma, those with college degrees, and those with advanced degrees. There is simply no principled way to identify and define those groups that should receive extra scrutiny from those that do not. In short, injecting "environmental justice" considerations into section 112(f) standard setting would inappropriately cause arbitrary policy and political considerations to trump objective scientific analysis. This would be patently unreasonable and, as such, would not be a supportable interpretation of section 112(f).

IV. Technology Review

A. We Support the Conclusion that There Are No New Control Technologies that Should Be Required

In the preamble to the rule, EPA states "For chemical pulping and bleaching, we have determined that there have been no advances in emission control measures since the subpart S standard was originally promulgated in 1998" (See 76 Fed. Reg. 81344). In addition, EPA noted that "Our technology review of kraft condensates did not yield any information about new technologies that could become the basis for regulatory options" (See 76 Fed. Reg. 81345). AF&PA agrees with these statements. The technology used by the industry for Subpart S compliance is the same as when the rule was promulgated. These systems have the same capabilities as the units that were used by the "best performing" mills that were the basis for the MACT "floor."

B. Condensate Collection & Treatment Standards

In the preamble to the rule, EPA states "For kraft pulping condensates, we have determined that the technology has sufficiently advanced since the 1998 MACT rule to warrant the development of an updated standard" (See 76 Fed. Reg. 81344). AF&PA does not agree with this statement.

Clean Air Act Section 112(d)(6) directs EPA to "review, and revise *as necessary*...[the initial MACT standards] (taking into account *developments* in practices, processes, and control technologies)" (emphasis added). EPA is now proposing to revise the condensate treatment requirements ***not because*** the Agency has identified any new developments in processes or treatment technologies beyond what EPA identified

when establishing the MACT "floor,,***but simply because*** EPA believes it has data indicating that wastewater treatment systems and steam strippers achieve control efficiencies greater than the 92% that the current MACT rules require. Firstly, there is not support of the Agency's conclusion in the available data.[14] Additionally, even if this were true, this is not a sufficient finding to warrant revising the MACT standards pursuant to section 112(d)(6) (and EPA lacks any other authority for revising the Subpart S MACT standards[15]).

The analysis of stripper performance test data in the docket is inadequate and we believe EPA lacks an understanding of what the data represent. The test data are not summarized to the extent that they could be verified by the companies that submitted such data within EPA's massive Information collection request effort. Individual test data are not even listed in the docket. We believe the data are largely initial compliance test data as required by the rule. These tests confirm compliance with the rule with a necessary margin to assure compliance over the range of operating conditions the stripper will see. The same is true of analogous waste water treatment system controls. A margin of compliance determined under initial performance test conditions verifies proper design and construction of the equipment and not that "technologies have advanced." Further, there is no adequate description we could find in the record on how EPA is considering to modify stripper and wastewater treatment systems to achieve a higher 94 % destruction efficiency, while maintaining a margin and certainty of compliance needed for operation over the range of conditions present. Finally, the calculated pound per ton compliance option requirements, purportedly consistent with the 94% efficiency objective, could not be achieved, in any way we could determine, without more than doubling the investment in control equipment. The logic employed in developing the pound per ton proposed requirements clearly appears flawed. These concerns are developed more fully in more specific comments that follow.

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[14] *Interim comments on rationale and methodologies used to evaluate and propose increased treatment requirements for kraft condensates in the Pulp and Paper ITR,* NCASI Memo to Ms. Robin Dunkins, Mr. John Bradfield, Mr. Bill Schrock, February 17, 2012. – This memo outlines other factors to be considered while reviewing condensate treatment data reported in the ICR and why it is inappropriate to attribute the performance to technological or operational improvements. – Discussed in Section IV.C2 and provided as Attachment 4.

[15] Congress structured section 112 unlike other provisions of the Clean Air Act (and other environmental statutes). Under CAA sections 112(c)(2) and 112(e), EPA was given definite deadlines for promulgating MACT standards for various source categories. The MACT "floor" thus represented performance at a specified point in time. Congress did not give EPA authority to review periodically the performance achieved by the "best performing" facilities, but only to determine, at least every eight years after the MACT "floor" was established (and any more-stringent "beyond-the-floor" MACT standards were justified), whether it is necessary to revise the MACT standards to account for "developments in practices, processes, and control technologies."

When the statute directs EPA to revise MACT standards only where "necessary…taking into account developments" in process and control technology, EPA must identify specific changes in the applicable technology that necessitate a change in the standard. EPA has not done so here. Neither the preamble to the proposed rule nor any document we could identify in the docket describes new control technology for pulp mill condensates, nor even advances in the condensate collection and steam stripper technology that was the basis for existing condensate treatment standards. Rather, EPA has concluded that it can set a more-stringent limit that can be met by some mills using the *same* technology that was the basis of the existing MACT standards. Congress clearly did not intend for section 112(d)(6) to authorize that sort of tightening of the standard that companies have already taken the steps to meet, absent a specific change in available technology. (Moreover, as EPA has already acknowledged, even if new, more-effective treatment technology were available, EPA would still need to consider the cost-effectiveness of that technology and other factors (See *NRDC v. EPA*, 529 F.3d 1077, 1084 (D.C. Cir. 2008)). EPA has not conducted that sort of analysis here.

As discussed below, the only fact that EPA relies on to propose revised standards, purportedly under authority of CAA section 112(d)(6), is that some mills are achieving HAP removal rates greater than the 92% removal rate that was assumed for the current MACT standards. But that is entirely to be expected; in fact, it would be surprising if mills were meeting the MACT standards ***at all times*** and ***with a very high compliance probability*** and yet on average had treatment efficiencies no higher than the minimal efficiency necessary to comply with the existing MACT standards. For instance, sound engineering and environmental control practices would require a steam stripper to be designed and operated with a removal efficiency greater than 92% to assure compliance at all times. Even mills that were the best performers and were used to establish the MACT "floor" would have wanted to make further improvements in the amount of HAPs they collected, or the removal efficiency of their stream stripper, or both, to ensure that they could comply consistently with the MACT standards once promulgated. Nothing in the language of section 112(d)(6), the legislative history of section 112, or common sense suggests that Congress wanted EPA to constantly "ratchet-down" the MACT standards, removing the margin of compliance that facilities have built into their HAP control systems. Adjustments are appropriate only when there are advances in practices, processes, or control technologies."

1. Condensate Generation

The MACT standards for the Pulp and Paper Industry (Subpart S) require affected facilities to collect and treat condensates generated in the pulping process. These condensates contain varying concentrations of HAPs, of which methanol is the

predominant one and is used as a surrogate in the rule. These HAPs are then apportioned throughout the process to the pulp, pulping liquors, condensates, and gas streams, also known as non-condensable gases (NCGs). Some methanol remains in the liquor and will be destroyed when the liquor is burned in the recovery furnace to recover sodium and sulfur. Methanol that remains in the pulp carries over to the bleach plant (if applicable) and the paper machines. Throughout the process, water containing relatively low concentrations of methanol is sent to the wastewater treatment system (WWTS). For the purposes of compliance with Subpart S, HAPs are collected from either the gases or condensates from the pulping and evaporator equipment. NCASI studied the generation and portioning of methanol during the development of the "Cluster Rule" (of which Subpart S is the air portion), and NCASI Technical Bulletin No. 702 covers those details.

EPA proposes to change the condensate treatment requirements (See 76 Fed Reg 81354, section 63.446). In order to understand how these proposed changes can affect the industry, it is important to both understand how and where condensates are generated and the variability in generation between those processes and facilities. Processes at each mill are slightly different and the differences affect the partitioning of methanol. The ability to treat condensates is governed by the fact that methanol has an affinity for water, and it takes a lot of energy/resources to drive methanol from the liquid phase. Therefore, of the condensates generated, only the concentrated streams, which contain the overwhelming majority of the methanol, can be effectively and efficiently treated in steam strippers.

Collecting and treating more process methanol results in greater and greater cost of destruction and makes less and less sense given the acceptable risk conclusion at current treatment levels. MACT was set at a more reasonable treatment efficiency and condensate collection rate because the systems that comprised the "floor" were designed almost entirely for odor control, and these decisions were made with a necessary mind towards reducing odor (and therefore methanol and other HAPs) cost-effectively. Higher levels of control or collection cannot be construed as an "advance in technology" but only as a design requirement to ensure compliance is achieved with a reasonable margin of assurance.

2. Background on Condensate Collection & Treatment Compliance Options in the original NESHAP

The MACT standard was divided into two phases of implementation. Phase I set the limits for condensate collection and treatment and also required collection and treatment of Low Volume High Concentration (LVHC) NCG streams. During Phase II,

mills were required to collect and treat High Volume Low Concentration (HVLC) NCG streams.

In 1993, there were 32 mills with steam strippers and the top 15 were used to develop the MACT "floor" (top 12% of all 125 mills that were covered by the rule). It is noted that the top 15 mills were all bleached mills. A NCASI study documenting HAP collection and treatment at all sources (NCASI Technical Bulletin 661) identified that the best performing 15 mills collected on an average 11.1 lb/ODTP of methanol and achieved a treatment efficiency of 92%. Based on average collection of methanol by the top 15 strippers, EPA developed the collection standard of 11.1 lb HAP/ODTP, with methanol being the surrogate for HAPs (See 40 C.F.R. § 446(c)(3). The standard was adjusted to 7.2 lb HAP/ODTP for unbleached mills, given that unbleached mills generate methanol at a rate that is 64% of the rate at which methanol is generated by bleached mills (See NCASI Technical Bulletin 702).

The two primary methods for condensate treatment are (1) steam stripping, and (2) biological treatment. At the time the "Phase 1" requirements of the Subpart S rule were being developed, the technology used by most mills that had condensate treatment was steam stripping. Given the affinity of methanol to water and the fact that they could be effectively treated by the active organisms in existing aerated stabilization basins (ASB), biological treatment of the condensates, along with other mill wastewaters, was identified as a feasible alternative to attain a similar level of HAP reduction[16]. The condensates had to be transported in a hardpipe and introduced below the surface of the treatment system in order to minimize volatilization.

Both the condensate collection and condensate treatment requirements in the Subpart S rule were based on the average collection levels and performance of steam strippers at the best performing mills. As noted above, 11.1 lb HAP/ODTP was the average HAP collection of the "floor" steam strippers. As this was an average collection, it was noted that not even all "floor" mills could achieve a collection standard of 11.1 lb HAP/ODTP for bleached mills. Therefore, the 'named streams' approach was developed. The 'named streams' are locations where volatile HAPs are generated in concentrations that can be effectively treated.

[16] Most aerated stabilization basin (ASB) systems—the most common type of wastewater treatment systems at pulp mills--are more difficult to operate to achieve a 92% destruction efficiency than steam strippers, but they also require less routine downtime for maintenance than steam stripper technology and at less cost. The lb/ODTP treatment option accommodates lower treatment efficiencies if more condensate is collected and treated. These options grew out of the cooperative Cluster Rule effort after industry advanced wastewater treatment as an equally effective treatment system with lower energy requirements and downtime. Cooperative thinking is what led to the flexible structure inherent in the Cluster Rule and the relative "near-uniqueness" of individual mill compliance systems – equivalent control with the most practical design given conditions and constraints of individual mills.

To meet the condensate collection requirements for Phase 1, mills could either:

- Collect 11.1/7.2 lb HAP/ODTP (bleached/unbleached) from named streams
- Collect all 'named streams' (it was noted that some mills could not generate the amount of methanol in the lb/ODTP standard), or
- Collect 65% of HAPs contained in pulping, turpentine recovery, and evaporator systems (based again on the average collection of 'named streams' by "floor" mills) plus all HVLC/LVHC condensates.

(See 40 C.F.R. § 63.446(c).) It is noted that all these options required collection of 'named streams' as identified by the rule. (i.e., a mill could not take credit for collecting 'unnamed streams'.)

In addition to collection options, the current Subpart S rule offers four treatment options. These options were again developed based on the "floor" mills' performance in treating an average of 92% in their steam strippers and the outlet concentration of those units.

The options provided to treat the collected streams are:

- Reduce or destroy at least 92% by weight of the collected HAPs, or
- Remove or destroy at least 10.2 or 6.6 lb HAP /ODTP (bleached/unbleached mills), or
- Remove or destroy so the control device outlet HAP concentration is at or below 330/210 ppmw (bleached/unbleached) or
- Recycle condensates to an enclosed treatment system.

(See 40 C.F.R. § 63.446(e).) Based on these requirements, facilities designed systems to comply with the standards with an inherent margin of safety to ensure continuous compliance, given both process and control device variability. In other words, mills designed systems to achieve some level of control beyond what was required by the rule in order to ensure a compliance margin and demonstrate compliance <u>at all times (99%+ compliance probability)</u>. This is why it is not surprising for the average treatment performance to exceed the levels required by the current standards.

3. Clean Condensate Alternative

MACT I Phase 2 required the collection of HVLC gases from brownstock washer systems, oxygen delignification systems, and some deknotters, screening systems, and deckers. As the cost to collect these gases was high (high volume means larger piping systems and control devices that can handle the volume), the Agency developed

an alternative to collection and control of these streams, known as the Clean Condensate Alternative (CCA). This option allowed a mill to collect and treat additional condensates (named or unnamed streams) in order to achieve emissions reductions equivalent to those required from "Phase 2" of the rule for control of HVLC systems. (See 40 C.F.R. § 63.447.)

Facilities demonstrating compliance using CCA had to quantify emissions under a baseline scenario that reflected MACT I Phase I compliance. Facilities were not allowed to take credit for emission reductions resulting from compliance strategies chosen for MACT I Phase 1. For example, consider a bleached mill complying with the 11.1 lb HAP/ODTP collection requirement and demonstrating the need for 10% over-collection (12.21 lb/ODTP) in order to increase compliance probability and establish averaging times. Subsequently, this level of collection would be treated as the baseline for CCA and the Mill would have to achieve additional and surplus emissions reductions to offset not collecting the HVLC streams identified in the rule[17]. In order to demonstrate compliance under this option, the Mill would have to collect additional condensates over the example 12.21 lb HAP /ODTP baseline and achieve equivalent with the emissions reductions that would have been achieved by controlling the HVLC sources identified in Phase 2. A more complete example of an approach to CCA is described in Attachment 6.

C. Technology Has Not Changed for Condensate Treatment

The technology for condensate treatment has not changed since the development of the original Subpart S MACT "floor". EPA claims that the data collected from the ICR indicates that facilities are consistently treating condensates to a higher level than in the current rule. Firstly, the above conclusion cannot be drawn from the data.[18] Second, this conclusion rests on the erroneous assumption that an increase in treatment requirement from 92% to 94% can be implemented at a minimal capital cost of $36 million. AF&PA strongly disagrees with this statement. The systems in place were designed for a Phase 1 treatment standard; however, the 2011 ICR data reflected condensate collection and treatment being achieved as a result of both Phase I and

[17] Letter from R. Douglas Neeley, EPA Region IV, to Larry Webber, Georgia EPD, March 27, 2003. "Any extra streams or additional mass of condensate used as an operating cushion, or for determine the need for flexibility provided by a longer averaging time cannot be used as credit for the CCA, since it was granted and used to meet the collection requirements of § 63.446."

[18] *Interim comments on rationale and methodologies used to evaluate and propose increased treatment requirements for kraft condensates in the Pulp and Paper ITR,* NCASI Memo to Ms. Robin Dunkins, Mr. John Bradfield, Mr. Bill Schrock, February 17, 2012. – This memo outlines other factors to be considered while reviewing condensate treatment data reported in the ICR and why it is inappropriate to attribute the performance to technological or operational improvements. – Discussed in Section IV.C2 and provided as Attachment 4.

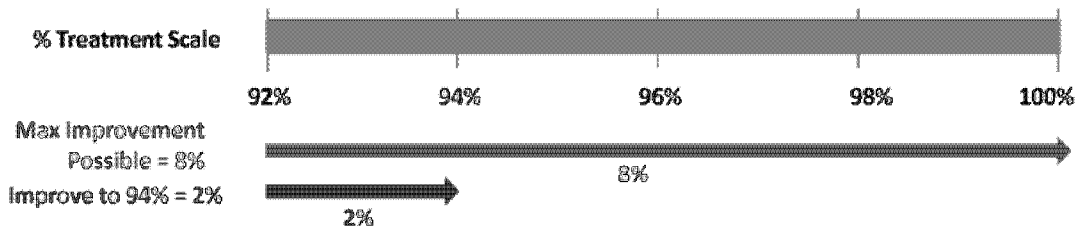
Phase 2 requirements. Thus the survey responses included mills using CCA or other equivalency-by-permit alternatives to meet Phase 2 requirements. EPA's conclusions resulted from a misinterpretation of the ICR responses and application of an inappropriate calculation methodology.

1. Clarification of the Proposed Numerical Limits

NCASI and AF&PA have previously pointed out to EPA that the numerical HAP treatment levels EPA has proposed, supposedly reflecting an increase in methanol removal efficiency from 92% to 94%, are greater than the current HAP collection requirements. (40 C.F.R. § 63.446(c)(3)) allows bleached and unbleached kraft mills to comply with condensate standards by collecting for treatment condensates from listed equipment that contain a total HAP mass of 11.1 lb/ODTP or more, or 7.2 lb/ODTP or more, respectively. Yet, the proposed § 63.443(e)(4) and (5) would require those mills to demonstrate that they are removing at least 12.8 lb/ODTP or 8.3 lb/ODTP, respectively.) The proposal to increase the required HAP reduction (e.g., from 10.2 lb/ODTP in the current rule to 12.8 lb/ODTP, for bleached kraft mills and from 6.6 lb/ODTP in the current rule to 8.3 lb/ODTP, for unbleached kraft mills) is not consistent with the proposed rule's stated basis: that the removal efficiency can be increased from the 92% to 94% and that no additional condensates need to be collected.

In the equivalency calculation used to arrive at these numerical limits, EPA has calculated the percent increase in control for each 1% increase in treatment efficiency from 92% to 98% (the level of control achieved for mills choosing the condensate recycling option). The rationale is represented graphically below:

Figure 2: EPA Calculation Methodology



The percent ***"standard improvement"*** [19] corresponding to an increase in treatment efficiency from 92% to 94% would be:

- 2% of the maximum possible 8% = 2/8 = 25%

Using this approach, the percent ***"standard improvement"*** for each 1% increase in treatment efficiency (from 93% to 98%) would be:

- At 93% - 1% of max possible 8% = 1/8 = 12.5%
- At 94% - 2% of max possible 8%: 2/8 = 25%
- At 95% - 3/8 = 37.5%
- And so forth.

These percent ***"standard improvements"*** were subsequently directly applied as scaling factors to arrive at numerical treatment limits (Table 2 in the October 23, 2011 Memo, reproduced here).

[19] "Summary of Kraft Condensate Control Technology Review," EPA Memorandum to Docket – EPA-HQ-OAR-2007-0544-0128, John Bradfield and Kelley Spence, October 23, 2011, page 4.

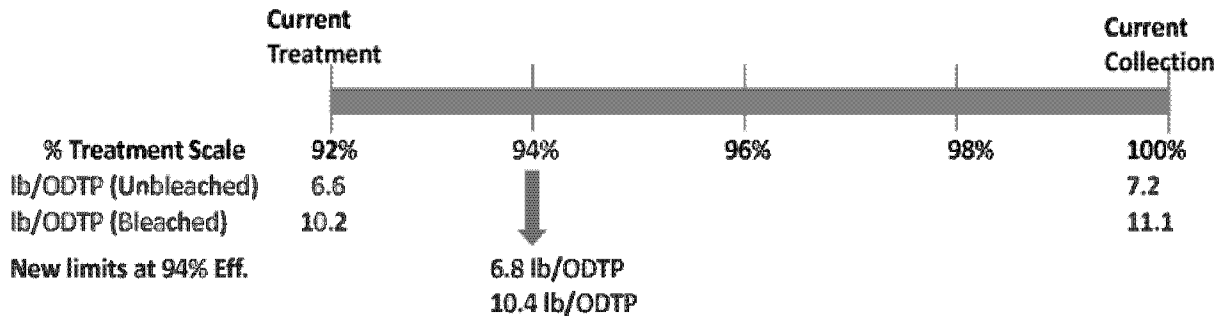
Table 3: EPA Scaling Factors and Recalculated Numerical Limits

		Recalculated Numerical Limits (lb/ODTP)	
% Treatment (% control improvement)	Multiplication Factor Used	Bleached Mills	Unbleached Mills
92%		10.2	6.6
93% (12.5%)	**1.125**	11.5 (= 10.2 x 1.125)	7.4 (= 6.6 x 1.125)
94% **(25%)**	**1.250**	12.8 (= 10.2 x 1.25)	8.3 (= 6.6 x 1.25)
95% (37.5%)	**1.375**	14.0	9.1
96% (50%)	**1.500**	15.3	9.9
97% (62.5%)	**1.625**	16.6	10.7
98% (75%)	**1.750**	17.9	11.6

As discussed during the meeting between OAQPS and the AF&PA on Jan 12, 2012, this methodology of calculating numerical limits is inconsistent with the premise behind the equivalency approach. Key insights from the equivalency approach highlight this issue:

- The scale ranging from 92% to 100% is the treatment scale
- Assuming that whatever is not treated/controlled is released as emissions, emissions would reduce from 8% to 0% as treatment increases from 92 to 100%
- The percent ***"standard improvements"*** calculated above are, in effect, ***emissions reductions.***
- In other words, a 2% increase in the numerical treatment efficiency standard is equivalent to a 25% reduction in associated **remaining** emissions.
- When calculating numerical treatment limits, the applicable scaling factors should therefore reflect the original ***treatment*** scale and not the percent ***"standard improvement" (emissions)*** scale. As done in the original rulemaking, the lb/ODTP treatment requirement is simply calculated by multiplying the collection requirement by the proposed percent control efficiency as shown below.

Figure 3: AF&PA Recommended Calculation Methodology



Recalculating the Numerical Treatment Standards for Kraft Process Condensates

The numerical treatment standards corresponding to the 94% treatment level can be calculated directly as shown below. They are represented on the treatment scale above.

- 7.2 lb/ODTP x 0.94 = **6.8 lb/ODTP** for unbleached mills
- 11.1 lb/ODTP x 0.94 = **10.4 lb/ODTP** for bleached mills

An alternate approach to calculating these numerical treatment levels that is logically consistent with applying EPA's statements about increasing treatment efficiency from 92 to 94 percent using the percent ***"standard improvement"*** scale would be as follows:

- Collection levels are 7.2 lb/ODTP and 11.1 lb/ODTP (unbleached and bleached respectively)
- At 92%, the treatment levels are 6.6 lb/ODTP and 10.2 lb/ODTP
- Therefore, when increasing the treatment standard from 92% to 94%, you achieve a ***25 percent "standard improvement" (reduction in emissions)***
  - 6.6 + ***25% of*** (7.2 – 6.6) = **6.8 lb/ODTP** - unbleached mills
  - 10.2 + ***25% of*** (11.1 – 10.2) = **10.4 lb/ODTP** - bleached mills

In developing the ppmw option that equates to 94% removal, EPA used the correct calculation methodology. For example, the current standard for bleached mills is 330 ppmw at the outlet of the control device. Since this standard was based on a treatment efficiency of 92%, it would be assumed that the inlet condensate concentration is 4,125

ppmw (330 / (1-0.92)). If the treatment standard were raised to a level of 94%, the outlet concentration would need to be lower than 248 ppmw[20] (4125 ppmw x (1-.94)).

In addition, EPA calculated that the rule would result in the reduction of 4,000 tons of HAP emissions per year. Based on the assumption that 97 mills produce an average 1,000 ODTP/day and the average decrease in emissions would be 0.2 lb/ODTP (equivalent increase in the standard calculated using the AF&PA methodology) the result is a reduction of approximately 3,500 ton HAP/yr which is in line with the EPA estimate.

2. ICR Data Was Inappropriately Interpreted

OAQPS staff suggested informally, during a meeting with industry representatives on January 12, 2012, that the mass HAP reduction standard proposed in this rulemaking can also be justified by ICR data. This is inconsistent with rule language in the proposal which suggests that the proposed numerical limits are based on a supposed equivalency between a 94% removal rate and a lb/ODTP mass reduction (See 76 Fed Reg 81345). We therefore do not have anything in writing explaining the basis for the proposed mass removal rate requirements. This prevents the industry from commenting effectively on the December 27, 2011 proposed rule. Nevertheless, EPA has suggested in subsequent discussions that information reported by mills in response to the Part I ICR supports the proposed rule. At AF&PA's request, NCASI has attempted to analyze the ICR data to help EPA understand its significance. During the January 12 meeting with industry representatives, EPA also provided a spreadsheet summarizing the data EPA had culled from industry responses to the Part I ICR.

Since that meeting, NCASI was able to access the entire set of responses EPA received to the Part I ICR. In response to EPA's proposal to increase assumed stripper (or biotreatment) efficiency from 92 to 94%, NCASI has determined that the ICR data are not sufficient to support that proposal (or any increase in treatment efficiency above the current MACT standards). With respect to lb/ODTP condensate treatment levels, NCASI has analyzed the ICR responses to assess whether they could be used to support a conclusion that technology improvements would allow for more stringent condensate treatment requirements.

In its review, OAQPS has subcategorized kraft mills based on the type of treatment performance data provided in the ICR. Specifically, OAQPS reviewed the mass treatment levels (lb/ODTP) reported by both unbleached and bleached mills to

[20] "Summary of Kraft Condensate Control Technology Review," EPA Memorandum to Docket – EPA-HQ-OAR-2007-0544-0128, John Bradfield and Kelley Spence, October 23, 2011, page 4.

ascertain whether operational improvements had been realized by facilities. As discussed in the meeting with AF&PA and NCASI on January 12, 2012, several other factors need to be considered while reviewing condensate treatment performance data reported in the ICR and attributing that data to technological or operational improvements. These other factors are provided below:

- **Facilities using the Clean Condensate Alternative (CCA)** - For facilities complying with the HVLC system requirements under §63.443 using CCA (§63.447) or other "equivalency by permit" options, the reported condensate treatment levels reflect compliance with the requirements under both §63.446 and §63.447 (Phase 1 and Phase 2, respectively). Therefore, as indicated by EPA in the meeting, it is inappropriate to attribute the combined treatment values to Phase 1 treatment requirements. (An example CCA compliance option is discussed in Attachment 6.)

- **High performance biological treatment systems** – A handful of facilities demonstrate compliance with Phase 1 by treating hardpiped condensates in high rate biotreatment systems like activated sludge treatment (AST), anaerobic treatment, or UNOX. These dedicated high rate systems can operate at higher treatment efficiencies than traditional Aerated Stabilization Basins (ASB). As a consequence, these systems are generally paired with lower lb/ODTP collection levels (closer to the 11.1 lb/ODTP collection requirement for bleached mills). The focus in these systems is to collect higher-concentration (lower-volume) condensates and to minimize flow (which is a significant determinant in system capital and operating costs). The trade-off is higher treatment efficiency on a smaller (more-concentrated and lower-volume) amount of HAP for roughly equivalent pound-per-ton-treated performance.

  When percent treatment data from these systems are combined with those of ASBs and the "combined average" is compared against the current 92% standard, there is a potential to erroneously conclude that ASBs are performing at levels above the current standard.

- **Operational and seasonal variability in biological treatment system performance** – Facilities have the option of collecting additional condensates in their hardpiping system in order to maintain compliance flexibility, i.e., to be able to demonstrate compliance using either the "percent removal" or "lb/ODTP" treatment options. Additionally, reported treatment levels also reflect safety margins required to demonstrate ongoing compliance with treatment requirements over the wide range of operational situations that exist throughout typical pulp mills.

- **Facilities demonstrating compliance using steam strippers** – The reported percent destruction OR percent removal numbers reflect equipment performance during one or two Initial Performance Tests (IPT). These datasets are snapshots of performance immediately following commissioning or scheduled maintenance and reflect safety factors inherent in equipment design. These design factors are essential to ensure ongoing compliance at the level of the current standard. They compensate for the gradual degradation of performance from the higher initial level of control to the minimum control requirement over normal maintenance cycles, largely attributable to fouling or scaling of heat transfer surfaces in contact with process condensates. Initial performance tests would, by nature, capture the high end of designed performance.

From the data requested in the ICR it would not be possible for EPA to discern the relative importance and contributions of these factors, particularly in the context of the wide flexibility in compliance options, the design variations, and operational differences that exist among individual compliance systems. Recognizing this, companies responding to the ICR had requested that EPA confer with them in analyzing the data in order to ensure that conclusions reflected a thorough understanding of process variations and realities. EPA chose not to communicate on these issues in developing the proposed standards.

The ICR data provided by OAQPS was analyzed by NCASI in order to further illustrate the points reiterated above. NCASI drew the following conclusions from their analysis[21]:

- Mills Reporting Percent Removal in Biotreatment Systems
    - Only 4 mills have reported percent removals in biotreatment systems that (a) are representative of Phase 1 compliance and (b) can be compared against the current requirement of 92%. This is too limited a list from which to draw substantive conclusions on over-performance.
    - Additionally, the percent removal data do not indicate control levels in excess of current requirements (when compared against the **actual** $F_{bio, methanol}$ of 94%).[22]

[21] These conclusions (and the ones for unbleached mills and steam strippers below) address performance data as it pertains to condensate treatment. More detailed comments on the inherent variability in condensate collection levels, and compliance strategies used to accommodate the same, are provided in Section IV.C3.

- Information from such a limited list of mills is not an adequate basis for revising the current percent removal standards

- Unbleached mills reporting mass treatment levels (lb/ODTP)
  - Only 3 facilities remain on the list with reported *lb/ODTP treatment levels reflective of Phase 1 compliance.* Data from such a limited number of facilities is not an adequate basis for revising the numerical condensate treatment standards.

- Bleached mills reporting mass treatment levels (lb/ODTP)
  - For facilities employing Steam Strippers, reported treatment levels reflect equipment performance during one or two initial performance tests. These datasets reflect performance immediately following commissioning or scheduled maintenance and reflect safety factors inherent in equipment design. These factors are incorporated during equipment design and are essential to ensure ongoing compliance at the level of the current standard (i.e., 92%).
  - Given the limited number of mills remaining on this list, it is inappropriate to use treatment information available from these mills as the basis to revise the condensate treatment standards.

The details of this analysis are included in Attachment 4.

3. Variability in Condensate Collection

The amount of methanol generated and subsequently collected in condensate streams varies significantly between mills. This variability is driven by process type and final product quality (batch vs. continuous pulping, unbleached vs. bleached, bleaching sequences, and oxygen delignification). Studies have also shown that, for any given mill, there is significant day-to-day variability in methanol content of condensate streams. Consequently, mills need a reasonable averaging time to demonstrate compliance with the collection requirements. Facilities have used site-specific data on variability and, in many cases, a statistical calculation methodology, to demonstrate the need for this averaging period. The majority of the facilities use either a 15-day or 30-day averaging period to demonstrate compliance with these requirements.

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[22] The need to demonstrate "treatment equivalency" for non-methanol HAPs means that in order to demonstrate an ***effective*** methanol treatment efficiency of 92% ($F_{bio,\ adjusted}$), the ***actual*** methanol treatment efficiency ($F_{bio,\ methanol}$) would have to be at 94%. Details provided in Attachment 4.

A statistical approach was outlined by NCASI, during the original rulemaking, to calculate the averaging periods required to demonstrate compliance. The methodology and factors affecting this calculation are detailed in Attachment 7. The Relative Standard Deviation (RSD) for methanol collection is calculated from mill-specific data. The averaging period needed to demonstrate compliance is calculated for the following scenario:

- Mill over-collecting condensates by 10%, and
- Demonstrating compliance with a 95% compliance probability.

This approach can also be extended to other compliance probabilities AND over-collection levels. In order to address the issue from the perspective of over-collection and to illustrate its importance in demonstrating compliance, Table 4 below extends this analysis to include the following:

- Facility utilizes a 15-day averaging period to demonstrate compliance
- For a given RSD, the levels of over-collection required to demonstrate compliance at different compliance probabilities are calculated
- This exercise is repeated for varying RSD levels

Table 4: Over-collection levels to demonstrate compliance with lb/ODTP collection requirements (Basis: 15-day averaging period)

	% Compliance Probability				
RSD	**95%**	**96%**	**97%**	**98%**	**99%**
20	9	10	11	12	14
25	12	13	14	15	18
30	15	16	17	19	22
35	17	19	20	23	27

As an example, a facility with an RSD of 30, in site-specific condensate methanol content, would have to do the following:

- Over-collect methanol by 22% to demonstrate compliance with a 99% compliance probability

- In other words, a bleached mill would have to collect 13.5 lb/ODTP and an unbleached mill would have to collect 8.8 lb/ODTP in order to demonstrate compliance with reasonable assurance 99% of the time
- In order to demonstrate compliance with a 99% probability, even with a 15-day averaging period, a facility needs anywhere from 14 to 27% of methanol over-collection depending on the Relative Standard Deviation (RSD) of collection data.

Table 4 provides a snapshot of daily variability in methanol content in condensates at four mills, again illustrating the need for over-collection to demonstrate compliance with high % compliance probabilities, *at the level required by the current standard.*

Table 5: Condensate Collection Characteristics at four kraft mills

	Condensate Collection Characteristics		
Source	Avg. Daily Collection, lb/ODTP	Standard Deviation (SD)	RSD
Mill A (Bleached)	12.7	3.2	25.1
Mill B (Unbleached)	9.5	3.1	32.5
Mill C (Bleached)	15.1	3.4	22.4
Mill D (Bleached)	17.7	4.4	25.0

Given (a) the above discussed variability in methanol collection and (b) the requirement to demonstrate compliance *at all times*, the above analysis illustrates the following:

- Over-collection is an essential part of the compliance strategy used by mills.
- Over-collection levels and averaging times serve to increase compliance certainty with the condensate collection requirements.
- Therefore, numerical average data on collection levels that exceed currently promulgated levels (11.1 lb/ODTP and 7.2 lb/ODTP for bleached and unbleached mills, respectively) *should not be interpreted as performance* at levels exceeding the current standard.

4. Treatment System Variability

In addition to the factors already mentioned, the proposed increase to the treatment standard inappropriately fails to address the need to account for treatment system variability in both biological treatment systems and steam strippers.

Biological Treatment Systems

During the original development of the standards, four HAPs were identified in pulping condensates: methanol, propionaldehyde, acetaldehyde, and MEK (the latter is no longer a HAP, by definition, but is still included in this rule). For the HAPs other than methanol, technology did not exist to measure concentrations below 1 ppm. Given that the concentration of these three compounds is typically below 1 ppm in ASBs, during the timeframe of the original rulemaking, there were uncertainties in quantifying and estimating the biotreatment efficiencies for these compounds. Facilities were therefore given the following option to demonstrate "treatment equivalency" for non-methanol HAPs:

- As a worst case, assume 0% treatment efficiency for non-methanol HAPs in biotreatment systems.
- In lieu of treating these non-methanol HAPs, demonstrate equivalency by treating an additional quantity of methanol equivalent to the amount of non-methanol HAPs.

Industry agreed to the development of an "r-factor" – the mass ratio of non-methanol HAPs to methanol HAPs - as a means to establishing this treatment equivalency. More details on the r-factor approach have been provided as part of NCASI Interim comments.[23]

When using a nominal average "r-factor" of 0.02 (based on NCASI studies), this treatment equivalency demonstration means that the **actual** $F_{bio,\ methanol}$ has to be 94% in order to achieve an adjusted F_{bio} of 92%. This compliance aspect is essentially written into the rule and not an option. Therefore, ASBs, as currently regulated, have to operate at a higher standard w.r.t methanol removal than strippers.

NCASI reviewed the reported treatment efficiencies in the ICR responses. A compilation of data on "intra-facility" variability in ASB performance, extracted from the 2011 Pulp and Paper ICR, was provided as part of interim comments submitted by

[23] *Interim comments on rationale and methodologies used to evaluate and propose increased treatment requirements for kraft condensates in the Pulp and Paper ITR,* NCASI Memo to Ms. Robin Dunkins, Mr. John Bradfield, Mr. Bill Schrock, February 17, 2012. – Provided as Attachment 4.

NCASI, dated February 18, 2012 (Attachment 4). The average "intra-facility" variability in $F_{bio,\ methanol}$ was about 5% according to this data.

- As it pertains to biological systems, this level of operational variability suggests that these systems would periodically operate at levels below the required 92%.
- As noted above, these mills must treat condensates at a minimum level of 94% for methanol to achieve the 92% treatment level for all HAPs.
- With an inherent efficiency variability of 5%, mills would need to operate at higher treatment efficiencies in order to maintain continuous compliance.
- Now, if these mills are required to increase treatment of all HAPs from 92 to 94%, the **actual** methanol removal efficiency would now have to be 96%
- After accounting for operational variability, it is unrealistic to mandate a 96% **actual** methanol removal in ASBs. EPA has not performed as analysis on whether this level of *ongoing control* is feasible, and it is unclear whether upgrades to systems would even be feasible or effective if implemented.

Steam Strippers

Steam strippers used for Subpart S compliance were designed and sized based on the collection and treatment requirements. These units are maintained to stay above the required treatment levels for compliance margin purposes (based on surrogate parameters). As previously mentioned, the reported efficiencies for steam strippers are generally based on the 3-run initial performance test (conducted when units were new or after maintenance and that represents an optimized performance level of the unit and not a sustained performance level). The results reported are expected as the unit should perform at or near the peak of system design during the performance test as this is generally when the unit is "clean" and operating at its highest efficiency and not representative of the minimum efficiency the unit can sustain between maintenance outages/cleanings. While the units can have higher "peak" efficiencies, most were designed to achieve a continuous treatment efficiency of 92%. If the performance tests results were not over 92% with a good margin of safety, a facility could not have confidence that the unit would be able to continuously meet the treatment standards. .

5. Increase in Treatment Efficiency to 94% Is Not Appropriate or Justified

EPA has not justified or supplied information in the docket that documents or justifies the proposed increase in treatment efficiency to 94%. The documentation states that based on EPA's analysis "the average percentage removal of kraft condensates was

96.2 percent."[24] This is the sole basis for the proposed increase in treatment requirements. The Agency did not evaluate the control technologies utilized for compliance with this Subpart and the ability for these systems to perform at higher efficiencies. Nor did it identify the changes needed to the MACT floor technologies to achieve these higher efficiencies. As noted in these comments, EPA has misinterpreted the ICR data and not taken into account system variability, the need for compliance margin, or the higher standard currently required by wastewater treatment systems. Therefore, it is inappropriate for the Agency to propose a higher standard without evaluating the current limits of the control systems in place or documenting how facilities will comply with the proposed standards.

D. EPA Has Underestimated the Economic Impact of the Proposed Rule

EPA is required to consider costs under 112(d)(6). EPA estimated the capital cost of the proposed modifications to the condensate standards at $36 million and projected annual costs of $ 4.1 million ($1,000/ton HAP), based on 7 mills needing to upgrade their biological treatment systems and 8 mills needing to upgrade their steam strippers[25]. AF&PA believes the capital cost to meet an increase in required treatment efficiency from 92 to 94% would be closer to $300 million ($152 million annually, or $38,000/ton HAP) (for an increase in condensate treatment only, using the AF&PA methodology for the equivalent lb/ODTP treatment (10.4/6.8 lb/ODTP), and not the lb/ODTP limits (12.8/8.3 lb/ODTP) proposed by EPA that are not achievable without additional collection). In addition, most of the emission reductions would be methanol, which EPA's own risk analysis shows does not present a risk and is of relatively low toxicity.

EPA did not include any information in the preamble to the Dec. 27, 2011 proposed rule or in the docket describing how EPA expected mills to comply with the new standards. Therefore, AF&PA carefully examined what would be necessary to comply with the proposal. It should be noted that all cost estimates in these comments are based on the best information available given the limited time to gather data during the 60 day comment period. These are based on conservative estimates of upgrades and number of units affected and not detailed mill-by-mill engineering estimates. Even with

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[24] "Summary of Kraft Condensate Control Technology Review," EPA Memorandum to Docket – EPA-HQ-OAR-2007-0544-0128, John Bradfield and Kelley Spence, October 23, 2011, page 2.

[25] "Costs and Environmental and Energy Impacts for Subpart S Risk and Technology Review" Appendix B-2, EPA Docket HQ-OAR-2007-0544-0124, Memo from Thomas Holloway, Katie Hanks, & Corey Gooden of RTI to John Bradfield & Bill Schrock, U. E. EPA, November 17, 2011. ("EPA 11/17/2011 Cost Document").

these caveats, the estimates are an order of magnitude higher than EPA's. These estimates are somewhat different from those presented to OAQPS on January 12, 2012 because AF&PA made further refinements and gained more information from member companies.

EPA estimated that a change in treatment efficiency from 92 to 94% would result in the reduction of 4,000 tons of HAPs from the industry per year. (See 76 Fed. Reg. 81345, 81349.) This estimate assumes that all 97 mills achieve a 0.2 lb/ODTP HAP reduction, at a production rate of 1,000 ODTP per mill per day.[26] However, EPA estimates only 15 mills will be required to spend capital to comply with the proposed standard. (Id.) The 15 mills for which EPA generated an estimated compliance cost would only achieve a total estimated annual HAP reduction of 547 tons (0.2 lb/t x 1000 tpd x 365 d/yr x 15 mills / 2000 lbs/t). Therefore, if EPA's assessment of the number of mills that would need to make upgrades to meet the proposed 94% reduction requirement and the cost for them to do so were inaccurate, the correct estimated cost/ton would be $7490/ton, rather than the $1000/ton stated by EPA. But even that cost per ton (to control mostly methanol) is much lower than what AF&PA believes would be the true cost per ton of increasing required condensate treatment from 92% to 94% efficiency, as shown below.

1. Cost Impact To Comply with 94% Treatment Efficiency (assuming 2% nominal change in lb/ODTP limit as identified by AF&PA)

As noted above, AF&PA believes that Agency incorrectly calculated the proposed lb/ODTP treatment standards that are equivalent to 94%. For the purposes of this estimate, it is assumed that the treatment standards equivalent to 94% are 10.4/6.8 lb/ODTP (bleached/unbleached). AF&PA estimates that total capital costs would be approximately $320 M, with annual costs of $152 million, or $38,000/ton (using the same 4,000 tons of reductions identified by EPA).

[26] See EPA 11/17/2011 Cost Document.

Table 6: Costs of Proposed Condensate Treatment Standards (assuming nominal 2% change in treatment efficiency)

	Capital Cost	Annualized Capital[27]	Annual Energy Cost	Annual Maintenance Cost	Total Annual Cost
Stripper Upgrade	$ 94 M	$ 8.8 M	$ 8 M	$ 3 M	$ 20 M
Current Strippers (Energy Only)			$ 8 M	$ 3 M	$ 11 M
Aeration	$ 230 M	$ 21.6 M	$ 90 M	$ 9 M	$ 121 M
Nutrient Addition				$ 2 M	$ 2 M
Total Cost	**$ 324 M**	**$ 30.4 M**	**$ 106 M**	**$ 17 M**	**$ 154 M**

The costs developed by AF&PA are based on the following (See Attachment 5):

- Upgrades to both steam strippers and wastewater treatment systems will result in control systems that can achieve the required treatment efficiencies.
    - Achieving higher treatment efficiency in steam strippers will require more energy, trays, and steam contact area per incremental percent reduction. .
    - Estimates assume the 10% downtime provision for steam strippers remains in place; otherwise a back-up control device (at a minimum) will be needed, which would significantly raise costs.
    - For wastewater treatment systems, it was assumed that an increase in aeration and nutrient addition would be sufficient to achieve the requirements. For reasons describes above, however, wastewater treatment systems are currently required to target treatment levels close to 99% to comply with the current standard of 92%. As required efficiency increases, upgrading the wastewater treatment systems will become technically infeasible and cost prohibitive. In many if not most cases, it will not be feasible to respond to increased required treatment efficiency through upgrading the condensate collection and wastewater treatment system, and the mill would most likely decide to install a new stand-alone steam stripper, at much higher cost than estimated. However, to be conservative, AF&PA assumed that all 39 mills that utilize only the WWTS as a condensate control devices will only need increased aeration and nutrient addition to achieve a 94% control efficiency.

[27] Capital costs annualized using the same 0.094 capital recovery factor EPA used, see EPA 11/17/2011 Cost Document. p. 4.

- The cost EPA assumed for steam stripper upgrades is $2.7 M each. We used $2.9 M based on information from member companies.
- Strippers can either be stand-alone units or integrated. Based on some initial input from members, AF&PA identified 10 integrated units. Since the total number of strippers being utilized for Subpart S compliance is 52, it was assumed that 20% of strippers that required upgrades were integrated and the remaining 80% were stand-alone units. As it is unlikely that integrated units can be upgraded in the same way as stand-alone units, the estimated unit costs are twice the cost for a stand-alone unit.
- EPA assumed 8 strippers would require upgrades to meet the 94% treatment efficiency requirement. AF&PA believes that 27 mills would actually require upgrades, based on the need for a margin of safety for compliance at 96% removal. Therefore, we assumed that mills that only have a stream stripper for condensate control and reported a treatment efficiency at or below 96% (23 mills) would need upgrades. We also assumed that 50% of the mills that have dual treatment systems (6 mills that utilize both steam stripping and biological treatment and the 2 mills that utilize steam stripping and recycling) that reported treatment efficiencies at or below 96% would need steam stripper upgrades, for a total of 27 mills that would require steam stripper upgrades.
- Capital costs for increased aeration were based on the average cost for four different mills. In addition to the capital costs outlined above, each mill would have an increase in operating costs.
    - Additional energy to operate steam strippers at a higher efficiency
    - Additional energy to operate more aerators in the wastewater treatment system.
    - Additional maintenance for steam strippers to maintain higher treatment efficiencies
    - Additional maintenance for aeration and nutrient addition equipment
    - Not only will these daily activities add more cost to implement the proposed changes, but it will also increase emissions from combustion units required to generate additional energy in the form of steam and/or electricity. EPA has not accounted for these additional costs or energy impacts in its evaluation.

In considering whether to make the existing MACT standards more stringent pursuant to CAA section 112(d)(6), EPA must take into consideration the cost of achieving additional emission reductions and non-air-quality health and environmental impacts and energy requirements. See *NRDC v. EPA*, 529 F.3d at 1084. EPA has not done so, even with respect to EPA's greatly understated estimate of the expenditures required. Additionally, in Executive Order 13563 President Obama directed EPA to assure, to the extent allowed by law, that the benefits of any new rule justify its costs

and that EPA chose regulatory approaches that minimize the net burden imposed. EPA can and should consider such factors in a technology review under CAA section 112(d)(6). Requiring an expenditure of more like $38,000 per ton of methanol removed is not at all cost-effective. Requiring a diversion of $300,000,000 of capital from other productive investments to address an insignificant risk, and with it increasing mills' energy needs for the higher steam stripper performance, is not a reasonable action under section 112(d)(6).

2. Cost Impact To Comply with Proposed Pound-per-Ton Removal Limits)

For the purposes of this estimate, it is assumed that the treatment standards are those published in the December 27, 2011 Federal Register, and that mills wishing to use the compliance option based on demonstrating the mass of HAP removed per ton of pulp produced would have to demonstrate the 12.8/8.3 lb/ODTP (bleached/ unbleached) removal rates in the proposal (rather than the nominal increase in removal rates associated with increasing condensate treatment efficiency from 92% to 94%, described above). AF&PA estimates that total capital costs would be approximately $830 M, and annualized capital costs plus operation and maintenance costs would be over $200 M, or 50 times greater than EPA estimated.

Table 7: Costs of Proposed Treatment Standards (lb/ODTP requirements)

	Capital Cost	Annualized Capital	Annual Energy Cost	Annual Maintenance Cost	Total Annual Cost
Stripper Upgrade	$ 94 M	$ 8.8 M	$ 8 M	$ 3 M	$ 20 M
Current Strippers (Energy Only)			$ 8 M	$ 3 M	$ 11 M
Aeration	$ 230 M	$ 21.6 M	$ 90 M	$ 9 M	$ 121 M
Nutrient Addition				$ 2 M	$ 2 M
HVLC Collection to Single Treatment Device	$ 510 M	$ 47.9 M			$ 48 M
Total Cost	**$ 834 M**	**$ 78.3 M**	**$ 106 M**	**$ 17 M**	**$ 202 M**

As explained above, the proposed lb/ODTP standard for condensate treatment would require additional collection of condensates. This is based on the investments described above, plus the following:

- Currently 38 mills utilize the Clean Condensate Alternative in section 63.447 for MACT I Phase II. Of those 38 mills, 34 demonstrated compliance

through collection of additional condensates, which will need to be increased. If those mills are required to demonstrate an increased removal of HAPs in condensate of approximately 25%, as EPA has proposed, then based on their current configurations the mills using the CCA likely could not continue to rely on the CCA to comply with the new lb/ODTP removal requirements. Therefore, it is assumed that all mills currently using the CCA will need to collect HVLC gases and route them to a single control device. This cost is estimated at $15 million per mill. This cost assumes the 4% venting provision for HVLC systems remains in place; otherwise a back-up control device (at a minimum) will be needed, at substantial additional cost.

Again, in considering whether to make the existing MACT standards more stringent pursuant to CAA section 112(d)(6), EPA must take into consideration the cost of achieving additional emission reductions and non-air-quality health and environmental impacts and energy requirements. EPA has not done so, even with respect to EPA's greatly understated estimate of the expenditures required. Imposing a cost of approximately $200,000,000 per year to achieve only an incremental reduction in emissions of mostly methanol would not be cost-effective. Requiring a diversion of $834 million in capital from other productive investments to address an insignificant risk, and with it increasing mills' energy needs for the higher steam stripper performance, is not a reasonable action under section 112(d)(6).

E. Need for Flexibility

As noted above, based on the residual risk analysis, implementation of MACT was successful in reducing emissions and health risks from the Pulp and Paper Subpart S Subcategory. Part of the success of the program is due to the flexibility of compliance alternatives. There are currently three collection and four treatment compliance approaches along with the CCA and "equivalency-by-permit" options. Every mill is different in its approach to achieve compliance with the standard. These differences include:

- The quantity and quality of the condensates generated at the Mill
- The compliance approach for MACT I Phase 2 (collect HVLC streams or use the CCA option),
- The control devices and options used to achieve the treatment standards (dual treatment systems, over-collection of condensates to compensate for lower treatment efficiencies, etc.), and
- Pulping technology options (e.g., continuous and batch digesters), heat balances; sulfidity, equipment arrangements, ambient conditions, space limitations, receiving water constraints, water supply limitations

Maintaining flexibility is imperative to ensure that mills can maintain compliance (minimize emissions and residual risk) and manage energy use while staying competitive in a global marketplace. The proposal to raise the treatment standard from 92% to 94% jeopardizes compliance for facilities that designed their collection and treatment systems to achieve compliance with the current standard. .The proposed treatment standards of 12.8/8.3 lb/ODTP (bleached/unbleached) threaten to negate the lb/ODTP treatment compliance approach as well as the CCA and equivalency by permit (EBP)[28] MACT I, Phase 2 compliance alternatives. While the rule offers other options for collection and treatment, mills cannot easily convert compliance approaches without significant costs. The industry spent over $1 billion to achieve compliance with the pulp and paper MACT standards, and the end result was an acceptable level of residual risk as stated in the preamble: "we conclude that the current standard, before the amendments proposed here are put in place, protects public health with an ample margin of safety" (See 76 Fed. Reg. 81344). It is not reasonable and is legally unwarranted to make changes to the standards that have significant financial impacts and remove flexibility, when there is acceptable residual risk and minimal benefit to the environment from further tightening the standards. EPA failed to make an adequate demonstration in its analysis and record for changes of these magnitude, and thus current requirements should be retained.

V. Excess Emission Provisions

Subpart S requires that various processes in the pulp mill be enclosed and vented into a closed-vent system and routed to a control device. The regulations provide that periods of excess emissions must be reported but will not be considered a violation if, for each semi-annual reporting period, the time of excess emissions (excluding periods of startup, shutdown, or malfunction) divided by the total process operating time does not exceed 1% for control devices used to reduce emissions from the LVHC system and 4% for control devices used to reduce emissions from the HVLC system (or used for both LVHC and HVLC systems). *See 40 C.F.R. § 63.443(e)*. For control devices used to treat pulping process condensates from specified pulp mill processes with a steam stripper, the excess emission provision (including periods of startup, shutdown, or malfunction) is 10% of total operating time during a semiannual period. *See 40 C.F.R. § 63.446(g).* In addition to continuous monitoring of the control devices, the regulations require indicators on closed-vent system bypass lines, periodic inspections for leaks, procedures for prompt repair of defects in the enclosures or piping, inspection and maintenance recordkeeping, and so forth.

[28] Under §63.94, a facility can propose an alternative compliance approach that would be equivalent (plus other benefits) to compliance with the standard. It is similar to the CCA in that it offers flexibility, but it allows the facility to determine the approach. For example, a facility could decide to control the vents of the Black Liquor Oxidation System (BLOx) as part of the EBP approach.

In addition to conducting the eight-year review of developments in control technologies under Clean Air Act section 112(d)(6) and the residual risk review under Clean Air Act section 112(f) for the Pulp and Paper category, EPA has indicated recently that it is considering eliminating or modifying the excess emission provisions in 40 C.F.R. § 63.443(e) and 40 C.F.R. §63.446(g) (See 76 Fed Reg 81346). It would be improper and unlawful to do so. Moreover, EPA would need to publish a proposed rule for public comment before it could change the excess emission provisions.

AF&PA appreciates EPA granting an extension until June 27, 2012 to provide information related to excess emission provisions.[29] This time will be critical for NCASI to undertake the survey described in their letter to Robin Dunkins.[30] Although we could defer providing any information to you on this issue, we wanted to share our legal views and general observations about their need and use. We will provide additional comments on the subject before June 27, 2012.

Industry was not aware of the potential for this evaluation until approximately one month before the rule was published. As such, there has been little coordination between the Agency and AF&PA to discuss the justification for these provisions or the implications of changing them. Therefore, in addition to filing subsequent comments, AF&PA would like to work with the Agency and set up meetings to discuss these issues, as they are complex, and an efficiency will be gained through coordination to assist the Agency in comprehension of these systems and their limitations and to develop realistic conclusions.

A. Legal Arguments

1. Current Excess Emission Provisions Represent MACT and Were Included in the MACT "Floor"

The excess emission provisions in the current Subpart S regulations reflect EPA's careful determination, after years of study of a large quantity of emissions information and public comments, that the MACT "floor," representing the emissions of the "best performers," includes emissions during unavoidable periods of releases of uncontrolled or partially controlled pulping process vent gases and unavoidable sewering of untreated or partially treated pulping process condensates (See 63 Fed.

[29] February 22, 2012 letter from EPA Assistant Administrator Gina McCarthy to AF&PA Vice President Paul Noe.

[30] See e-mail dated February 15, 2012 from Vipin Varma of NCASI to Robin Dunkins of EPA's Sector Policies and Programs Division.

Reg. 18504, 18529 (April 15, 1998)). "EPA established appropriate excess emission provisions to approximate the level of backup control that exists at the best-performing mills and the associated period of time during which no control device is available." *Id.* After "an analysis of the public comments and the available data regarding excess emissions and the level of backup control in the industry," EPA determined that the "best-performing mills achieve a one percent downtime in their LVHC system control devices" and "best-performing mills achieve a four percent downtime in the control devices used to reduce emissions from their HVLC system to account for flow balancing problems and unpredictable pressure changes inherent in HVLC control systems." *Id.* "The allowances address normal operating variations in the LVHC and HVLC system control devices for which the equipment is designed. The variations would not be considered startup, shutdown, or malfunction under the Part 63 General Provisions…." (See 63 Fed. Reg. 18530). The 10 percent excess emission provisions for steam strippers systems "accounts for stripper tray damage or plugging, efficiency losses in the stripper due to contamination of condensate with fiber or black liquor, steam supply downtime, and combustion control device downtime." *Id.*

EPA adopted the excess emission provisions after reviewing extensive data from continuous monitoring systems and considering industry comments that although some mills had backup combustion devices as part of their LVHC control system, venting of pulping gases is an essential safety practice (because of their explosion hazard) even for those systems with backup control devices, since the startup of, and transfer of vent gases to, the backup controls cannot be immediate or automatic for safety reasons, and operating variability in the control devices themselves was unavoidable for process and other reasons. See, e.g., Pulp, Paper and Paperboard Industry – Background Information for Promulgated Air Emission Standards – Final EIS, EPA-453/R-93-050b (October 1997) ("BID") at 4-81, 4-82 to 4-84; AF&PA April 18, 1994 comments on the proposed MACT standards for Pulp and Paper Mills, p. MACT-61 (events resulting in venting of NCGs are "integral to process variability," and combustion devices will "predictably" not perform at their design efficiency "some small percentage of the time, even when they are being operated properly and all equipment is in order"); id. p. MACT-173-74. For HVLC systems, few mills had backup controls that could handle the large volume of vent gases, so any standard that required the use of backup devices would have been beyond the MACT "floor" and would not have been cost-effective due to the low concentration of pollutants in the large gas stream (See 63 Fed. Reg. 18529; BID at 4-81 to 4-82; AF&PA April 18, 1994 comments at MACT-61 (degree of venting allowance needed is "independent of the availability of backup combustion devices because of the safety and engineering concerns"); *id.* at MACT-174 (backup combustion devices for HVLC systems could be an additional cost of $1 billion).

In short, the MACT determinations that EPA made when promulgating the Subpart S emission standards correctly concluded that available technology involves unavoidable periods where not all vent gases or condensates can be routed to the control device, and/or when the control device is inoperable or necessarily operating at a reduced rate. The Subpart S emission standards (including the excess emission provisions) were designed to reflect the performance of the MACT technology and the actual performance of the "best performing" mills. Without the excess emission provisions, the remainder of the Subpart S emissions standards would impose limitations not achieved even by the "best performers" and not demonstrated as achievable at any facility. This plainly is not what Congress intended. See, e.g., *Sierra Club v. EPA*, 353 F.3d 976, 980 (D.C. Cir. 2004); *Sierra Club v. EPA*, 167 F.3d 658, 665 (D.C. Cir. 1999).

2. There Is no Technical Justification for Eliminating the Excess Emission Provisions

EPA is supposedly carrying out Congress' directive in Clean Air Act section 112(d)(6) that, at least every eight years, EPA review whether "developments in practices, processes, and control technologies" necessitate revision of MACT emissions standards. Nothing has changed about the technology available to control volatile HAP emissions at pulp mills that eliminates the unavoidable excess emissions during the events that EPA accurately described when promulgating the current MACT standards. Absent such new technology, there is no statutory predicate for EPA to go back and change the MACT standards at this time. *Cf. NRDC v. EPA*, 529 F.3d 1077, 1084 (D.C. Cir. 2008) (rejecting contention that CAA section 112(d)(6) requires EPA to "start from scratch" and develop new MACT standards).

But even if the section 112(d)(6) technology review were an opportunity to second guess and revise the existing MACT standards, EPA has no technical basis for eliminating the Subpart S excess emission provisions. An agency cannot simply change its mind and reach a diametrically opposed conclusion from the determination made in a prior rulemaking. Rather, EPA must demonstrate sufficient basis for changing its prior conclusions; in this case, technical justification for concluding that mills with MACT controls do not experience the unavoidable variability described by EPA in promulgating the Subpart S regulations and accommodated by the excess emission provisions. See, e.g., *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 129 S. Ct. 1800, 1811 (2009) ("a reasoned explanation is needed for disregarding facts and circumstances that underlay…the prior policy"); *Transactive Corp. v. United States*, 91 F.3d 232, 237 (D.C. Cir. 1996).

There is no health or environmental imperative for eliminating the excess emission provisions in Subpart S. EPA has just completed an assessment of the risk to human health and the environment from Subpart S emissions, for its "residual risk" review. The conclusion of that assessment is that there is no significant risk from those emissions, including excess emissions allowed under the Subpart S regulation. The emissions data that EPA used in its risk modeling included emissions during bypassing of control equipment or other excess emissions covered by the Subpart S excess emission provisions.

3. Intervening Court Decisions Do Not Justify Eliminating the Excess Emission Provisions

The Subpart S NESHAPs were never judicially challenged, and the time for such a challenge under CAA section 307(b) has long passed. Even if there were some portion of an opinion in one of the many cases challenging other NESHAPs that was contrary to the approach EPA took in promulgating the Subpart S NESHAPs, that would not provide a means nor a justification for reopening the Subpart S standards that were never challenged on that grounds. See *id.* and, e.g., *Sierra Club v. EPA*, 353 F. 3d at 986 (MACT standards judged on the adequacy of EPA's explanation in the particular rulemaking, not on what EPA did based on a different record in a different rulemaking). But in any event, none of the holdings in those other cases undercuts EPA's determination to include the current excess emission provisions in Subpart S.

EPA may believe that elimination of the excess emission provisions is justified or required by the D.C. Circuit's decision in *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008), *cert. denied*, 130 S. Ct. 1735 (2010), which vacated the "exemption" for excess emissions during SSM events contained in the 40 C.F.R. Part 63, Subpart A General Provisions for emission standards for hazardous air pollutants. EPA suggests that the excess emission provisions are "arguably at odds with" that decision (See 76 Fed. Reg. at 81346). To the contrary, the D.C. Circuit's *Sierra Club* decision is not inconsistent with, and would not justify EPA's retroactive elimination of, the Subpart S excess emission provisions.

First, the *Sierra Club* decision interpreted the NESHAPs General Provisions, not the Subpart S NESHAPs or indeed any categorical NESHAPs. Secondly, the decision addressed an exemption for startups, shutdowns, and malfunctions, while the Subpart S excess emission provisions for pulping vent gases specifically does not address excess emissions during startup, shutdown, and malfunction (see 40 C.F.R. § 63.443(e)), and the provision for pulping condensates only covers such events because EPA did not have data to distinguish those situations from "normal stripper operating emissions" (See 72 Fed. Reg. 18529-30).

Thirdly, the *Sierra Club* decision rejected the General Provisions' blanket, open-ended exemption for emissions during startup, shutdown, and malfunction periods, finding it to be inconsistent with Congress's intention that "there must be continuous section 112-compliant standards" for sources subject to MACT standards, rather than periods where no standard of any kind applies. See 551 F.3d at 1027. The problem with the General Provisions SSM exemption, in the Court's eyes, was that it allowed sources to be exempt from any standard at all, and that it was not derived (by EPA's admission) applying the factors in CAA section 112(d) or 112(h). See *id.* at 1027-28, 1030. The *Sierra Club* opinion did not address a situation, such as the Subpart S standards, where EPA finds that the MACT standard, which applies continuously, must account for periods of higher emissions during unavoidable operational variability to accurately reflect the available technology and the best performers' emissions. See BID at p. 1-41 ("EPA established excess emission allowances to approximate the level of downtime and number of backup control devices that exist at the best-performing mills. The Excess emissions allowances are designed to account for periods when the control device is inoperable and when the operating parameter values established during the initial performance test cannot be maintained due to problems with the process."). (EPA's statement, in the preamble to the proposed rule, that the excess emission provisions of the current regulations "create time periods during which a source does not have to comply with a CAA section 112-compliant standard" (see 76 Fed. Reg. 81 346) is simply contrary to the record for the existing Subpart S rulemaking.)

B. Provisions Are Consistent with the Clean Air Act

As stated above, EPA lacks authority to go back and re-assess the existing MACT standards for reasons unrelated to CAA sections 112(d)(6) and 112(f). But even if EPA did, the excess emission provisions in the existing Subpart S regulations are entirely consistent with the Clean Air Act and with past EPA practice. First, they represent the performance of the best-performing mills, as EPA explained when it adopted the provisions. In fact, without the excess emission provisions, the Subpart S standards would violate CAA section 112. Section 112(d) standards based upon the performance of the best-performing facilities are supposed to represent "the emissions control that is achieved in practice" by the best performers, which means that the best-perfoming mills would not violate the standards, which "only results if 'achieved in practice' is interpreted to mean 'achieved under the worst foreseeable circumstances.'" *Sierra Club v. EPA*, 167 F.3d 658, 665 (D.C. Cir. 1999). The courts (and EPA) have recognized that there is variability in the performance of control technologies, which needs to be accounted for in establishing emission limitations based on the MACT floor. See, e.g., *Cement Kiln Recycling Coalition v. EPA*, 255 F.3d 855, 862-865

(D.C.Cir.2001). As the record reflects, it is certainly foreseeable that even the best performers would experience violations of the MACT standards, due to process variability and control technology limitations, without an excess emission allowance.

EPA implies that the excess emission provisions in the existing Subpart S regulations somehow are inconsistent with the D.C. Circuit's vacatur of the NESHAP General Provisions SSM exemption because they do not provide a numerical limitation on emissions during certain periods (See 76 Fed. Reg. at 81346). But nothing in *Sierra Club v. EPA* said that MACT standards have to be the same at all times; to the contrary, the Court recognized that they might not be. See 551 F.3d at 1021, 1027.

The excess emission allowances are no different in principle from the averaging periods that EPA applies almost universally in setting the MACT standards: a source complies with the average emission limitation even though there are times during the averaging period when the source's emissions are much higher than the rate specified in the standard. Also, EPA has included excess emission provisions analogous to those in Subpart S in NSPS issued under CAA section 111, even though the same definition of "emission limitation" and "emission standard" (relating to limiting emissions of air pollutants on a continuous basis) applies to NSPS. For example, in the NSPS for Kraft pulp mills, EPA recognized the complex factors affecting recovery furnace operations and provided an excess emission allowance (40 C.F.R. § 60.284(e)), in addition to the startup, shutdown, and malfunction provision in 40 C.F.R. § 60.8(c),

In effect, elimination of the excess emission provisions would put pulp and paper mills in a "Catch-22" situation: the MACT standards would no longer accommodate the excess emissions that EPA knows will occur regularly during normal mill operations, as a result of process variability and control equipment operations and availability. Yet those same events would appear to be ineligible for the "affirmative defense" that EPA proposes as a means of addressing excess emissions that occurr despite a source's proper design and operation, since the "affirmative defense" is only available for excess emissions that result from unforseeable and infrequent events (See proposed 40 C.F.R. § 63.456(a)). This would be unreasonable, arbitrary and capricious, and not in any way required by the Clean Air Act or judicial precedent.

C. Provisions Are Necessary due to Inherent Process Variability, Design, and Technology Reasons

Provisions for a small amount of LVHC and HVLC system venting and stripper downtime were developed as part of the MACT "floor," based on the fact that even the best-performing units could not meet the standards at all times. As the technology for the collection and treatment of HAPs under Subpart S has not changed, neither has the capability for mills to operate without needing these provisions. These provisions

are necessary due to process variability and not for situations defined as startup, shutdown, or malfunction (SSM). These events generally are not due to situations where some equipment has broken down and must be repaired to correct the situation, but are due to process variability and safety interlocks which have caused a situation that requires a release.

1. LVHC Systems

LVHC NCG gases are potentially explosive and cannot be burned safely without supplemental fuel. Most mills have both a primary and back-up control device[31] for the treatment of LVHC gases. These gases must be incinerated with support fuel and be interlocked to failsafe on loss of support fuel, combustion air, and/or boiler load. The flame safety system will not permit the gases to be admitted until the burner is operating on supplemental fuel and ignition is proven. Therefore, for gases to be introduced into any control device, several conditions, also known as permissives, must be met and the system has a series of interlocks that will not allow the introduction of gases unless all conditions are satisfied. These conditions are required for both safety and protection of process equipment. The safety interlocks are required by both Factory Mutual Insurance and the National Fire Protection Association for burning of these non-condensable gases. Also, when these gases are burned in a recovery furnace, there are safety guidelines issued by the Black Liquor Recovery Advisory Committee. Depending on the control device, the system may have anywhere from nine to fifteen interlocks.

The most common cause of an LVHC release is due to the loss of a flame or burner permissive for the control device. These events are typically short in duration and the situation quickly resolves itself. An example is an intermittent loss of burner in the destruction device due to loss of flame or flame scanner detection temporarily during cleaning of oil gun(s) on oil fired unit. Safe destruction of LVHC gases requires the presence of a burner in the destruction device for safety reasons to assure combustion of the gases. In most cases, the permissive allows a return to normal operation in less than five minutes. In cases where this does not occur, the mill would try to transfer treatment of the gases to the back-up control device.

In situations where the back-up control device is not immediately available (i.e., due to maintenance, the back-up system is not “hot”, etc.), the mill must analyze the situation and decide how to minimize emissions. If the mill anticipates the permissive will allow a return to normal operation in a reasonable amount of time, the facility will continue to operate rather than to implement an emergency shutdown that could result in higher

[31] Common control devices for LVHC gases include power boilers, lime kilns, stand-alone thermal oxidizers, and recovery furnaces.

emissions. If this is not the case, the mill will shutdown the Subpart S sources. Most states recognize this situation in that they allow facilities to run for a period of 1 – 4 hours (depending on the state) with the control device down before requiring notification and corrective action. The following list contains examples of events that can cause the isolation of the destruction device and venting of the LVHC NCG stream:

- Low steam supply pressure to the inductor, or
- Low steam flow to the inductor, or
- Low inductor outlet NCG flow, or
- Low inductor inlet vacuum, or
- High temperature downstream of inductor (flashback), or
- NCG nozzle pressure is inadequate (ensures proper furnace penetration), or
- Loss of main NCG header rupture disc, or
- A pressure instrument detects a high pressure event, or
- Main vent or double block and bleed valve vent valve not showing closed by limit switch, or
- Main auxiliary-fuel valve failure to open, or
- Loss of destruction device BMS permissive, or
- Low destruction device temperature, or
- Dedicated destruction devices:
    - Loss of quencher permissives
    - Loss of scrubber permissives
    - incinerator—quencher outlet temperature high-high alarm
- Any other condition relating to the safe operation of a destruction device

Another cause of unplanned releases is process variation. During these events, there is a vent at the process source until the operator or process logic control system can verify that there has not been an explosion in the system and the permissives will allow collection of the vent. In these situations, the system is operating within its design parameters and repairs are not necessary. An example is a paper machine trip which causes a domino effect throughout the mill (i.e., the machine trip causes a swing in the steam header pressure which results in over pressurization at the pulping equipment and a vent to open to relieve the pressure and prevent an explosion). The NCG system (LVHC or HVLC) will also automatically vent gases to atmosphere for any of the following process reasons associated with collection of individual sources which also typically cause the collection system main vent location to open by-passing the control device:

- High temperature, high pressure, or bypass rupture disc ruptured

2. HVLC Systems

The HVLC system is similar to the LVHC system in causes of venting events. "The best-performing mills achieve a four percent downtime in the control devices used to reduce emissions from their HVLC system to account for flow balancing problems and unpredictable pressure changes inherent in HVLC systems" (See 63 Fed. Reg. Vol. 72 at 18529 (April 15, 1998)). The main difference is that most HVLC systems do not have back-up control devices. Therefore, when the permissive prevents treatment of the gases, the mill must decide if emissions will be best minimized by waiting for the control device to become available or shutting down the HVLC sources. The following list contains examples of events that can cause the isolation of the destruction device and venting of the HVLC NCG stream:

- Loss of HVLC fan, or
- Low HVLC fan outlet flow, or
- Low HVLC fan inlet vacuum, or
- High temperature downstream of HVLC fan (flashback), or
- Loss of main NCG header rupture disc, or
- A pressure instrument detects a high pressure event, or
- HVLC vent valve not showing closed by limit switch, or
- Loss of destruction device burner management system permissive, or
- Low destruction device temperature, or
- Any other condition relating to the safe operation of a destruction device.

EPA recognized that most of the MACT "floor" mills controlling HVLC sources did not have back-up control devices, and therefore EPA provided for a longer excess emission provision under the rule. It should be noted that due to the volume of HVLC gases, the control options are typically limited to either a stand-alone incinerator, power boiler, or recovery furnace, and the gases are injected as combustion air.

3. Stripper Systems

Under the existing MACT standards, for both steam strippers and stand-alone biological treatment systems that treat only condensates periods of excess emissions are not violations provided that such periods do not exceed 10 percent of the total process operating time in a semi-annual reporting period. (See 40 C.F.R. § 63.446(g).) This provision was included in the current rule because the MACT "floor" mills did not have back-up control devices and could not treat condensates at all times. The 10 percent excess emission allowance includes SSM events, and it should continue to include these events because there is no backup for these systems. "The appropriate excess emissions allowance for steam stripper systems was determined to be 10

percent. The provision accounts for stripper tray damage or plugging, efficiency losses in the stripper due to contamination of condensate with fiber or black liquor, steam supply downtime, and combustion control device downtime. This downtime provision includes all periods when the stripper systems are inoperable including scheduled maintenance, malfunctions, startups, and shutdowns." (See 63 Fed. Reg. 18530 (April 15, 1998)). These systems require maintenance, and when there are problems with their operation, the systems can require significant work to get them back to serviceable condition.

D. Other Information Requested on Releases

1. Emission Estimates

EPA requested information on the estimated emissions that occur during periods covered by the excess emission provisions. It is not possible to quantify emissions on a site- or event- specific basis. We are not aware of any successful measurements of releases from vents during a release. Emissions will vary based on the cause, location, and source of the release. Emissions will vary not only between mills and sources but between the same sources at the same mill under different circumstances. NCASI has developed limited data sets for main vents (vents immediately prior to the control device that include gases from all collected sources) under normal operations. However, site-specific data cannot be collected for the releases listed above as the events cannot be anticipated, the events are typically short in duration, and it is unsafe to perform sampling. The reasons EPA gave for not setting emission limits in the original standards have not changed. "At proposal EPA did not have sufficient data to establish a mass emission limit or a mass emission reduction percentage across each mill."

Since proposal, EPA obtained site-specific information that was used to develop emission factors for various systems at a mill. However, these emission factors represent average or typical systems and are not specific to each mill. While EPA believes such information may be used to estimate national impacts, it is not adequate to determine the MACT "floor" level of control (i.e., the factors are not representative of the actual emissions at each mill but may be used to represent typical emissions from all mills). Actual mass emission levels or mass emission reductions would still be required. Information on the controls for various systems at each mill was available to EPA. Therefore, EPA decided to develop MACT "floors" on a unit (i.e., system) basis." See EPA-453/R-93/050b, October 1997, page 4-6.

Estimating total source category emissions associated with the excess emission provisions is very difficult, for the same reasons. During the extended comment period that EPA has allowed for comment on the excess emission provisions of the Subpart S standards, AF&PA, NCASI, and industry representatives will be exploring ways in which the industry might respond to EPA's request for emission estimates.

2. Work Practices Currently Employed

Under Subpart S, mills were required to develop SSM Plans. Mills use these plans and standard operating procedures to define the work practices mills must follow to minimize emissions during a release.

3. Procedures To Monitor Releases

Depending on the process and system design, mills monitor the location and time of releases by pressure (most popular), valve position, temperature at the vent location or flow meters. Facilities record this information either electronically or in log books and report events as currently required under Subpart S.

4. Ventless Transfer Systems

Some systems can be designed for ventless transfer between the primary and back-up control device; however, these systems cannot prevent venting 100% of the time. It is noted that these systems would only experience ven less transfer if all the conditions are met such that the interlocks do not prevent introduction of the gases to the alternate treatment device. However, some units cannot be designed for ventless transfer. Examples include:

- Systems with recovery furnaces, to assure the burner is not plugged. Light-off of the igniter must be initiated at the burner front, and then only after inspecting the burner opening in the furnace wall to ensure that there is no plugging
- Systems that have different types of boilers as the Primary and Back-up Control Devices (i.e., one boiler is under positive pressure and the other boiler is under negative pressure)
- Systems such as oxidizers that were installed as Back-up Control Only (these units are typically not maintained in a "hot" state to immediately accept gases to minimize fuel burning and emissions, and for energy conservation)

E. Response to EPA's Questions on Provision Options

As noted above, AF&PA believes that the excess emission provisions should be maintained in the rule. These provisions are necessary for technological reasons due

to system design for safety reasons and process operating variability – not due to a desire not to be penalized for excess emissions during periods of SSM. Prior to the revision of the standard, EPA must propose a new rule and allow for a comment period. Although AF&PA does not believe a change to the provision is required, if the EPA moves forward, the only acceptable alternative is a work practice. The Clean Air Act states "if it is not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a hazardous air pollutant or pollutants, the Administrator may, in lieu thereof, promulgate a design, equipment, work practice, or operational standard, or combination thereof,"[32]. In order for an emission standard to be infeasible the Administrator must determine that "the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations."[33]

1. Technological Limitations

Development of a numerical emissions standard (other than tracking vent time) is not feasible due to limitations in technology. As discussed above, there are no data available to quantify site-specific emissions from the vents of LVHC and HVLC systems. In addition, the emissions impact of stripper downtime is not clearly understood as condensates would generally be sewered to the wastewater treatment system. There may be losses to the air from any sewers that are open to the atmosphere prior to introduction to the biological treatment system, but these are unknown.

Even if time were allowed to collect additional data, it is not possible to measure the emissions from these events, as they do not occur under normal operating conditions, the exact time and location of the event cannot be anticipated, and the events are generally short in duration. In addition, collection of these gases is not always possible as the locations are not always accessible and sampling of NCG gases outside the collection system would be dangerous.

For these reasons, there is not sufficient data available to develop a numerical emission standard.

[32] Clean Air Act, Section 112(h)(1)

[33] Clean Air Act, Section 112(h)(2)(B)

2. Economic Limitations

If the EPA were to eliminate the excess emission provisions, mills would need to install duplicate systems for collection and treatment of both NCG gases and condensates. This includes:

- Installing equipment to send HVLC gases to a backup control device (assuming the facility has an available control device that can be used as a backup)
- Installing redundant HVLC and LVHC gas collection systems, and/or
- Installing back-up steam strippers

AF&PA estimates that the costs to install these systems is $1.6 billion, which is cost-prohibitive and unnecessary given that EPA has determined that the risks associated with the current rule, which included emissions during venting, is acceptable. Even with these installations, there is no guarantee that a mill would be able to prevent all incidents of stripper downtime and/or venting due to process variability and safety concerns.

Table 8: Capital Cost Estimate for Redundant Systems

	Capital Cost
HVLC Redundant Control Costs	$ 500 M
Redundant LVHC/HVLC Collection Systems	$ 700 M
Back-up Strippers	$ 400 M
TOTAL	$ 1.6 B

Details of these costs are in Attachment 5.

VI. Performance Testing

A. Stripper Testing

EPA has proposed to require performance testing for facilities complying with standards in § 63.446 using steam strippers. Specifically, the EPA proposes to require testing once every 5 years. Currently, facilities that use strippers are required to conduct an IPT and then monitor surrogate parameters against limits developed during the IPT. It is noted that strippers are efficient systems when properly operated and maintained and the industry believes that the monitoring of surrogate parameters is

appropriate to indicate continuing stripper removal efficiency. However, we do not object to EPA's proposal to require performance testing every 5 years, as this will provide additional compliance documentation. (Note also that AF&PA objects to the proposal to change performance testing requirements to give EPA seemingly unfettered discretion to specify conditions for performance testing, as discussed in Section VIII.D. of these comments, below.

B. Sampling and Reporting Methods for Biological Treatment

In the preamble to the rule, EPA requests comments on the appropriateness of re-deriving the equation in Subpart S to demonstrate compliance with the condensate standards for biological treatment. Specifically, since methyl ethyl ketone (MEK) was removed from the hazardous air pollutant (HAP) list in 2005 and the current equation in Subpart S requires the sampling and analysis of MEK, should the equation be re-derived without MEK (See 76 Fed. Reg. 81347-81348). Evaluation of this equation will not affect the residual risk assessment and has nothing to do with whether the technology has changed. AF&PA recommends that this equation should not be re-derived. AF&PA along with NCASI spent a significant amount of time and effort during the original rule development to derive equations that would best demonstrate compliance with the standard based on conservative estimates. As previously noted, the approach assumes that non-methanol HAPs are not biologically treated and therefore the facility must treat an additional quantity of methanol. As this is a conservative approach and actually requires additional treatment by each facility, it results in lower emissions.

C. Repeat Air Emission Testing

In the preamble to the rule, EPA states that the Agency <u>does not</u> propose additional emissions testing for facilities that comply with the clean condensate alternative (CCA) approach, due to the complexity of these compliance demonstrations (See 76 Fed. Reg. 81347). AF&PA agrees with this decision, since these compliance demonstrations generally require the testing of both gas and liquid streams on multiple operating systems. This testing requires significant time and resources that are not easily coordinated. During the IPT for each facility utilizing CCA, the site had to demonstrate that the CCA approach would result in lower emissions than the traditional compliance approach for high-volume low-concentration (HVLC systems). Facilities also conduct monitoring to ensure continuing compliance. Thus, although this is an alternate approach, it is a conservative option and actually results in a higher treatment standard and thus lower emissions.

VII. Startup, Shutdown, and Malfunction (SSM)

AF&PA believes that the approach EPA is taking fails to account adequately for emissions that occur during SSM periods. EPA bases its actions on an incorrect reading of the D.C. Circuit's *Sierra Club v. EPA* decision and on unreasonable or insufficiently supported assumptions about SSM events and emissions during SSM periods. EPA proposes to change regulations that have been in place for many years and whose SSM provisions were never challenged in court, without any justification of its authority to do so and without any apparent factual analysis of the statutory criteria for standard-setting.

EPA has for decades recognized, in technology-based standards under the Clean Air Act and other statutes, that in many cases it is not feasible with the identified technology to achieve the same emission limitations established for normal operations during SSM periods. Historically, EPA has therefore applied different requirements during SSM events. EPA has not justified departing from that practice in the Proposed Rule. Nor has EPA made any attempt to demonstrate that the amended standards it is proposing reflect the performance actually achieved by best-performing existing sources or meet the statutory criteria for establishing beyond-the-floor maximum achievable control technology ("MACT") standards. Applying the same emission standards during SSM periods is not compelled by the statute nor by applicable case law, including the *Sierra Club v. EPA* decision EPA relies on, and EPA has several options for setting MACT standards for such periods, including establishing a design, equipment, work practice, or operational standard under CAA section 112(h) (hereafter referred to as "work practice standards").

EPA should revise the proposed standards to better account for SSM events, rather than try to rely on an "affirmative defense" to make up for its failure to do so. The affirmative defense EPA describes in the Proposed Rule inappropriately shifts the burden to the source to disprove alleged violations during malfunctions. In addition, the restrictions and requirements EPA proposes for the affirmative defense are unreasonable and impracticable. If EPA persists in relying on a defense contained in the standards in lieu of promulgating proper standards that apply during SSM periods, the affirmative defense in the Proposed Rule would at a minimum require substantial modification and streamlining.

A. EPA Does Not Have Authority to Amend Existing MACT Standards To Make Them More Stringent

While EPA does not make the distinction clearly in the Proposed Rule, the Proposed SSM Provisions, unlike the remainder of the Proposed Rule, are changes to existing MACT standards that EPA promulgated previously pursuant to CAA sections 112(d)(2) and (3) for the NESHAP category. The Clean Air Act does not contemplate, however, EPA returning to previously issued MACT standards to fill "gaps" or re-determine the MACT "floors." Rather, Congress established two distinct procedures for establishing standards more stringent than the original MACT standards: the eight-year review for new developments in control technology under CAA section 112(d)(6), and the review of MACT standards to determine whether more stringent limitations are necessary to protect human health under the CAA section 112(f)(2) "residual risk" review.

EPA's authority under CAA section 112(d)(6) is to "review and revise as necessary (taking into account developments in practices, processes, and control technologies), emissions standards promulgated under this section no less often than every 8 years." EPA did not invoke its section 112(d)(6) authority to support the Proposed SSM Provisions (See 76 Fed. Reg. at 81328), but even if it had, section 112(d)(6) does not provide broad authority to reconsider aspects of previously issued MACT standards unrelated to "developments in practices, processes, and control technologies." Thus, EPA cannot simply revisit and redo a MACT determination long after it has been issued, as EPA attempts to do with the Proposed SSM Provisions. EPA cannot merely change its mind about what standards are required to comply with CAA sections 112(d)(2) and (3), nor can it recalculate a MACT "floor" based on subsequent performance. *Cf. NRDC v. EPA*, 529 F.3d 1077, 1084 (D.C. Cir. 2008) (rejecting contention that CAA section 112(d)(6) requires EPA to "start from scratch" and develop new MACT standards).

Reassessing existing NESHAPs now, that were based on the MACT "floor" years ago, and imposing more-stringent requirements, would be inconsistent not only with the statute's careful provision of technology-review and residual-risk authority to follow establishment of MACT standards, but also with Congress's desire for finality evident in the judicial review provisions of CAA section 307(b). Challenges to MACT standards needed to be raised within 60 days of their promulgation. This provision ensures that regulated entities, EPA, and the public know what emission limitations will apply to a source, rather than having those limitations be subject to flux. In the instant case, facilities regulated by the NESHAPs long ago made capital investment decisions and developed and honed their operating procedures to meet the existing MACT standards. The CAA does not allow EPA simply to revisit the analysis and decisions involved in

developing emission standards that meet the requirements of CAA sections 112(d)(2) and (3).

Moreover, as discussed in greater detail below, even if EPA did have authority to go back and change the existing MACT standards, it would have to justify why the decisions reflected in the current standards are wrong and why the new standards meet the required criteria that EPA must satisfy in issuing MACT standards under CAA sections 112(d)(2) and (3). EPA has not made either showing in the Proposed Rule. EPA also would be required, under Clean Air Act section 112 and Executive Order 13563, to assess the costs and benefits of eliminating the SSM provisions in the current Subpart S standards. EPA has made no attempt to do so, nor has the Agency even identified what changes pulp and paper mills might make to their facilities in response to the elimination of the SSM provisions.

B. The Proposed SSM Provisions Are Not Required in Order To Be Consistent with *Sierra Club v. EPA*

EPA has recognized for decades that often it is unreasonable to require sources to meet technology-based emission standards, such as NSPS promulgated under CAA section 111, during SSM periods. See 40 C.F.R. § 60.8(c). That understanding has been a critical piece of most MACT standards as well, through incorporation by reference of the NESHAP General Provisions SSM requirements, inclusion of specific provisions for SSM events in the categorical MACT standards, or both. Despite that fact, in the Proposed Rule EPA proposes that established emission limitations in the affected NESHAP, which EPA has issued under CAA section 112 (which is modeled in part on section 111), would now be applicable at all times, even during SSM events. See, e.g., proposed sections § 63.443 and § 63.459.

EPA suggests that its treatment of excess emissions during SSM events in the Proposed Standards is appropriate, even "required," in order to make the standards "consistent with" the D.C. Circuit's decision in *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008), *cert. denied*, 130 S. Ct. 1735 (2010), which vacated the exemption[34] for excess emissions during SSM events contained in the 40 C.F.R. Part 63, subpart A General Provisions for emission standards for hazardous air pollutants under CAA

[34] Although the D.C. Circuit (and EPA in the preamble to the Proposed Rule) referred to the provision vacated in the *Sierra Club* decision as an "exemption" from hazardous air pollutant standards during SSM events, in fact other portions of the NESHAP General Provisions impose various requirements that apply to sources during SSM events (including the obligation to minimize excess emissions), and in anticipation of and following SSM events (including requirements to prepare a plan to address SSM events and to report SSM events).

section 112 (See 76 Fed. Reg. at 81345). The D.C. Circuit's *Sierra Club* decision does not, however, compel or even support EPA's adoption of the Proposed SSM Provisions.

First, the *Sierra Club* decision interpreted the NESHAPs General Provisions. It did not by its terms address what EPA may or may not include in category-specific MACT standards.

Secondly, the *Sierra Club* decision did not say that the same emission limitations that EPA has derived for normal operations must also apply during SSM events. While a blanket, open-ended exemption from any standard under Section 112 is inconsistent with the *Sierra Club* panel's holding that, for section 112 maximum achievable control technology (MACT) standards, "there must be continuous section 112-compliant standards" (551 F.3d at 1027), *Sierra Club* does not preclude EPA from applying different standards during SSM events than apply during normal operations. In fact, the opinion acknowledges that section 302(k)'s "inclusion of [the] broad phrase" "any requirement relating to the operation or maintenance of a source to assure continuous emission reduction" in the definition of "emission standard" suggests that EPA can establish MACT standards consistent with CAA section 112 "without necessarily continuously applying a single standard."[35]

There is ample precedent for EPA applying a different standard during SSM events. The language that the D.C. Circuit considered dispositive in interpreting EPA's standards-setting authority under section 112 — the statement in the CAA section 302 definition of "emission limitation" and "emission standard" that it "limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis" — has been in the statute since 1977. Throughout that time, EPA has not required sources to meet NSPS emission limitations under CAA section 111 established for normal operations during SSM events. See 40 C.F.R. § 60.8(c). In fact, Congress enacted the continuous basis" language in section 302(k) knowing that EPA's emissions standards under section 111 exempted SSM periods. There is nothing in the legislative history of the 1977 amendments to the CAA that suggests Congress intended to overturn that

[35] 551 F.3d at 1027. "Indeed, this reading is supported by the legislative history of section 302(k)." *Id.* See also *id.* at 1021 ("accepting that 'continuous' for purposes of the definition of 'emission standards' under CAA section 302(k) does not mean unchanging"); *id.* (referring to "the CAA's requirement that some section 112 standard apply continuously") (emphasis added). Moreover, since it was addressing only a generic SSM exemption, the *Sierra Club* decision did not consider whether EPA, in the context of individual categorical standards, could determine that it is infeasible to apply the same limits, or any limits on the mass or concentration of pollutants emitted at all, during SSM events, or that it would lead to absurd results to do so.

practice.[36] Moreover, court decisions both before and after the Clean Air Act Amendments of 1977, some of which are cited below, have affirmed the appropriateness of including special SSM provisions in standards issued under section 111—despite the "continuous basis" language in the definition of "emission limitation." Similarly, there is nothing in the legislative history of the Clean Air Act Amendments of 1990 that suggests Congress meant something completely different when it used the same defined terms, "emission standard" and "emission limitation," in directing EPA to establish MACT standards in the 1990 Amendments.

Thirdly, the *Sierra Club* decision did not address whether EPA could use a "design, equipment, work practice or operational standard," as authorized under CAA section 112(h) and included in the definition of "emission limitation" and "emission standard" in CAA section 302(k), in lieu of a numerical emission limitation during SSM events. EPA told the Court that the General Provisions SSM exemption struck down in *Sierra Club* was not an alternative standard based on the work practice standard authority. See 551 F.3d at 1028. Indeed, EPA argued in that case that section 112(h) was irrelevant to its authority to exempt excess emissions during SSM events. *Id.* at 1030 (Randolph, J. dissenting).

Thus, EPA cannot hide behind the *Sierra Club* decision as a justification for ignoring an inability of even the "best performers" to achieve during SSM events the emission limitations EPA has established for normal operations. Moreover, the approach EPA is proposing would not establish "continuous section 112-compliant standards" that the *Sierra Club* decision concluded are required. See 551 F.3d at 1027. Under CAA

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[36] Rather, the "continuous basis" language inserted in 1977 related to a debate in Congress about whether sources should be allowed to use temporary or intermittent pollution control technologies, as the D.C. Circuit recognized in *Sierra Club v. EPA*, 551 F.3d 1019, 1027 (D.C. Cir. 2008), *cert. denied*, 130 S. Ct. 1735 (2010), citing *Kamp v. Hernandez*, 752 F.2d 1444, 1452 (9th Cir.1985). See also Conference Report on H.R. 6161 (the CAA Amendments of 1977), H. Rep. No. 95-564 (August 3, 1977) at 129 (requirement to use "continuous emission controls" "clarifies that intermittent or alternative control measures are not permissible means of compliance"), 172; S. Rep. No. 94-717 (March 29, 1976) at 78 (definition of "emission limitation" being amended to clarify that "[i]ntermittent controls or dispersion techniques are unacceptable as a substitute for continuous control of pollutants" and contrasting intermittent controls, which vary based on predicted changes in pollutant dispersion due to meteorological predictions, with continuous controls such as flue-gas cleaning equipment); see also *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 434 n.54 (D.C. Cir. 1980) ("The 'intermittent' controls that concerned Congress were any of those which entailed temporary reductions in emissions when weather conditions were poor."). The language about "continuous reduction" in the definition of "emission standard" did not address what emission limitations apply during SSM periods, nor EPA's established practice of exempting excess emissions during SSM events from the performance standards applicable to normal operations. In fact, the legislative history indicates Congress was aware that alternative emission limitations might at times be necessary, even though the emission limitations were established based on the capability of "continuous controls" like scrubbers. See, e.g., S. Rep. No. 94-717 at 78 ("It is recognized that the source controls may not be available to achieve the full reduction required of a particular source under particular circumstances. In such case, supplementary programs can and should be developed. But this flexibility occurs only after imposition of the continuous emission limitation.").

section 112(d)(2), MACT emission standards must be "achievable." Moreover, if EPA sets the emission standards based on the "best performing 12% of units in the category" (the MACT "floor"), those limitations must on average be "achieved" by the best performers. See CAA section 112(d)(3); *Sierra Club v. EPA* (standards based on the MACT "floor" must be achievable "under the worst foreseeable circumstances").

An emission limitation that applies during SSM events does not meet the requirement of CAA section 112(d)(2) that "emission standards" under that section be "achievable" if in fact EPA has not demonstrated that the limitation is "achievable" with available technology, "taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements." Similarly, an emission limitation that applies during SSM events has not been demonstrated to be "achieved" by the best-performing 12% of units in the category under CAA section 112(d)(3) unless EPA can show that those best performers actually meet that emission limitation during SSM events. The Proposed Rule would not establish "continuous section 112-compliant standards" because, as discussed below, EPA has not demonstrated that the emission limitations in the existing MACT standards, if they also applied during SSM events, would comply with section 112 when applied to SSM periods.

That plain-language reading of the applicable statutory requirements is echoed by extensive case law. The courts have long recognized that a "technology based standard discards its fundamental premise when it ignores the limits inherent in technology." *NRDC v. EPA,* 859 F.2d 156, 208 (D.C. Cir. 1988). For example, the D.C. Circuit recognized, in *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 398 (D.C. Cir. 1973), a decision reviewing standards under CAA section 111, that "'start-up' and 'upset' conditions due to plant or emission device malfunction, is an inescapable aspect of industrial life and that allowance must be made for such factors in the standards that are promulgated." *Id.* at 399. Similarly, in *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 432 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974), another section 111 case, the court held that SSM provisions are "necessary to preserve the reasonableness of the standards as a whole." *Id.* at 433. In *National Lime Ass'n v. EPA*, 627 F.2d 416 (D.C. Cir. 1980), another case reviewing emission standards promulgated under CAA section 111, the court held that the analogous CAA requirement that NSPS be "achievable" means that the standards must be capable of being met "on a regular basis," including "under most adverse circumstances which can reasonably be expected to recur," including during periods of SSM. 627 F.2d at 431 n.46.

Courts have reached a similar conclusion when considering the analogous Clean Water Act requirements that EPA establish technology-based effluent limitations based on the best available control technology. In one such case the court held that where EPA knew that there would be periods where a discharger, even with "exemplary use of" the identified best technology, would exceed the effluent limitations because of conditions "beyond the control of the permit holder," EPA had violated the Clean Water Act by failing to provide an "upset provision" to address those periods. *Marathon Oil Co. v. EPA*, 564 F.2d 1253, 1273-74 (9th Cir. 1977). See also, e.g., *NRDC v. EPA*, 859 F.2d at 207 (distinguishing between technology-based effluent limitations, where some provision for "upsets" is required, and water-quality-based effluent limitations, which are tied to achieving water quality standards rather than based on available technology, and therefore need not include an upset provision).[37]

The 1977 CAA amendments if anything support the conclusion that emission standards need to deal with the inability of a source to meet the normal emission limitations during particular circumstances. Moreover, the *National Lime Ass'n* decision discussed above, which relied in part on the cases EPA referenced in the preamble, and which directly addresses the need for emission limitations that address reasonably anticipated adverse circumstances, post-dates the Clean Air Act Amendments of 1977 by three years.

As noted above, the *Sierra Club* decision does not prevent EPA from adopting emission standards for SSM periods that are different from those required during periods of normal operation. Nor does the *Sierra Club* decision mean that EPA is barred from using a "requirement relating to the operation or maintenance of a source to assure continuous emission reduction" as the emission standard that applies during such events. See 551 F.3d at 1027. The *Sierra Club* decision only rejected EPA's assertion that it had discretion to decide not to impose any emission standard covering SSM periods. See *id.* at 1027-28, 1030 (noting that EPA was not claiming that the General Provisions SSM exemption was either an emission standard under CAA

[37] The *Weyerhaeuser Co. v. Costle* decision EPA cites in the preamble to the Proposed Rule, 590 F. 2d 1011 (D.C. Cir. 1978), does not support EPA's position (See 76 Fed. Reg. 72535). In that case, the court was discussing a "technology forcing" standard, rather than one, like MACT, that is to be based on what is already being "achieved" or has been demonstrated to be achievable. Also, the SSM events that EPA acknowledges are expected to occur at sources subject to the Proposed Standards are a far cry from the "'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication, or insanity" that the Court was considering in the passage quoted by EPA, (See 76 Fed. Reg. 7535, col. 1). Industry is not requesting that the MACT standards provide relief from numerical emission limitations during those unusual types of events. Perhaps most importantly, the *Weyerhaeuser* decision came long before *NRDC v. EPA,* 859 F.2d 156 (D.C. Cir. 1988) which, as noted above, affirmed the need for an upset provision to address circumstances where compliance with effluent limitations is impossible through no fault of the permittee, and which endorsed *Marathon Oil*.

section 112(d) or a design, equipment, work practice, or operational standard under section 112(h)).[38]

Thus, despite EPA's implications to the contrary, the *Sierra Club* decision expressly recognized that different standards, including non-numerical standards, may (and in some cases must) apply during non-standard operating conditions, such as SSM.

C. EPA Must Fully Justify Applying the Same Emission Limitations During Startup and Shutdown as During Normal Operations

In the preamble to the Proposed Rule, EPA does not say that it is precluded from adopting different emission limitations that would apply during startup and shutdown periods. Rather, EPA states that "Nothing in the record suggests that the operations (and attendant emissions) are significantly different during startup or shutdown than during normal operations. Periods of startup, normal operations and shutdown are all predictable and routine aspects of a source's operations" (See 76 Fed. Reg. 81346).

As an initial matter, this falls far short of the "reasoned analysis" that an agency must supply before changing a prior decision. See, e.g., *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 42 (1983) ("an agency changing its course by repealing a rule is obligated to supply a reasoned analysis for the change"); *Williams Gas Processing-Gulf Coast Co. v. FERC*, 475 F.3d 319, 326 (D.C. Cir. 2006) ("it is axiomatic that agency action must either be consistent with prior action or offer a reasoned basis for its departure from precedent") (internal quotation marks and brackets omitted). In promulgating the Subpart S regulations, EPA specifically considered the need for special provisions to address higher emissions occurring during startup and shutdown (as reflected in EPA's decision to include startup and shutdown periods in the excess emission provision for condensate treatment but not for LVHC and HVLC NCG controls (See 63 Fed. Reg. 18529-30). If EPA wishes to change its prior determinations with respect to startup and shutdown provisions, it would have to explain how the Agency erred in arriving at those prior determinations, or how available information has changed since that time. The cursory treatment of this issue in the preamble to the Proposed Rule certainly is not sufficient justification for reversing EPA's prior determinations with respect to startups and shutdowns.

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[38] The statement in the majority opinion that "Congress gave no indication that it intended the application of MACT standards to vary based on different time periods," 551 F.3d at 1028: (1) is contradicted by other statements in the opinion, referenced above, that a MACT standard need not continuously apply a single emission limitation, (2) is *dicta*, because that was not the situation presented by the challenged regulations and argued by EPA, (3) ignores the extensive case law about technology-based limitations referenced above, and (4) does not in any event say that the CAA precludes EPA from adopting different emission limitations that apply during SSM events.

As EPA has acknowledged in other rules, there are numerous reasons why a source might not be able to comply, during periods of startup or shutdown, with emission limitations established based on performance during steady-state operation, even if the control devices used are started up before the process units and are operational during the shutdown phase of a process. For example, a control device may be less efficient until it reaches its design operating temperature, or it may be less efficient when the pollutant concentrations in the gases to be treated are lower than during steady-state operation (as they often will be when a process is starting up or shutting down) (See 68 Fed. Reg. 1276 at 1287-88 (Jan. 9, 2003)). On the other hand, until a manufacturing process reaches steady-state operation, that process may generate substantially higher emissions, either on a total mass basis or on a mass per unit of production basis (See 76 Fed. Reg. 63878, 63883 col. 2 (Oct. 14, 2011)).

EPA claims that ""Nothing in the record suggests that the operations (and attendant emissions) are significantly different during startup or shutdown than during normal operations" (See 76 Fed. Reg. 81346). There is no indication, however, that EPA has actually analyzed sufficient data on emissions during startup and shutdown to justify that conclusion, as opposed to merely assuming it is correct. EPA cannot conclude that special provisions for emissions during startup and shutdown are not needed based on "mere speculation." See *NRDC v. EPA*, 859 F.2d 156, 210 (D.C. Cir. 1988). The default assumption must be that they *are* needed. EPA previously determined, in establishing the existing Subpart S standards, that the best performers on which the MACT standards were based may not achieve those standards during startup and shutdown. EPA cannot simply change its mind about this sort of assessment without providing a factual analysis supporting EPA's new conclusion that MACT standards can be achieved during all startup and shutdown periods as well. See, e.g., *Transactive Corp. v. United States*, 91 F.3d 232, 237 (D.C. Cir. 1996). AF&PA doubts that emissions data representative of startup and shutdown events exist that would be sufficient for EPA to conduct a reasoned analysis to demonstrate the achievability of the MACT emission limits established for normal operations during startup and shutdown events (contrary to EPA's prior rulemaking), because of likely limitations in the available data.

There are several reasons why adequate data often do not exist to allow EPA to conclude that an emission limitation established for normal operations also represents the performance of the best demonstrated control technology during startups and shutdowns. To the extent emissions data come from required performance tests, the applicable regulations generally prohibit testing during SSM conditions, and require that data not be used for compliance purposes if obtained during a startup, shutdown,

or malfunction event.[39] To the extent EPA evaluates emissions data collected through continuous monitoring, the applicable regulations often require or allow the source to exclude from its reporting of continuous monitoring data those data reflecting SSM conditions. Also, atypical pollutant concentrations and other stack conditions that may exist during startup and shutdown can result in the continuous monitoring system producing unusable data because the pollutant concentration may be outside of the monitoring equipment's span or the stack conditions may not meet monitoring system QA/QC parameters, or the data may be truncated on the high end because of limitations of the monitoring equipment.[40]

These factors would cause EPA to understate emissions occurring during startup and shutdown. An additional problem is that it can be unclear whether a condition that leads to excess emissions should be characterized as a startup or shutdown event or a malfunction event. Without a clear demarcation (both in EPA regulations and in practice), EPA could be analyzing data sets that exclude events that were treated as malfunctions but that EPA would say should be included in calculating average performance as startup or shutdown conditions.

While EPA may not be able to calculate average HAP emissions during startup and shutdown periods, EPA certainly has available to it information that indicates that pulp and paper mills utilizing the MACT "floor" technologies and complying with the Subpart S standards during normal operations would not be able to comply during at least some startup and shutdown conditions. The simplest example is the requirement in 40 C.F.R. § 63 .443(c) that emissions from specific processes be vented into a closed-vent system and routed to a control device. As explained above, because these gases can be explosive, they cannot be routed to an incineration device unless the concentration and volume of the vent gas and the conditions in the incineration device meet certain conditions necessary to prevent explosions ("permissives"). When pulping processes are starting up or shutting down, the NCGs generated by the process may not meet permissives for a period of time, and the NCGs will have to be vented for safety reasons due to the increased variations in the process during starting up and shutting down. The same thing is true of startup or shutdown of a primary or

[39] See, for example, the NESHAPs General Provisions, which state that performance tests can only be conducted under representative conditions and which specify that: "Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test…." 40 C.F.R. § 63.7(e)(1); see also 40 C.F.R. § 60.8(c) (same for performance testing for NSPS).

[40] Note that data from periods when the monitoring system is outside of control limits are required to be excluded from emission averages under the NESHAPs General Provisions. See 40 C.F.R. § 63.8(c)(7)(ii).

backup incineration device (which may be a boiler, recovery furnace, lime kiln, or other combustion unit that is also part of the pulp mill operation), during which the conditions in the incineration device may not meet permissives for a period of time and it will be necessary to bypass the NCGs around that device to avoid explosion.

Another clear example has to do with requirements in 40 C.F.R. § 63.453 to monitor operating parameters in lieu of or in addition to monitoring emissions. Operating parameters established to represent proper operation during normal operating conditions will often be different from the operating parameters that apply when a unit is being started up or shut down.

In short, EPA already is aware of information that supports its determination in the original Pulp and Paper MACT rulemaking that these standards applicable to normal operations are not representative of performance (even of the best performers) during startup and shutdown conditions. AF&PA is aware of no information supporting EPA's suggestion in the preamble to the proposed rule that the opposite is true, and it does not appear from the record that EPA has conducted (or could conduct) any analysis to overturn its prior determination.

D. EPA Is Required To Take Malfunctions into Account When Adopting Emission Standards

EPA asserts that "EPA's approach to malfunctions" in setting emissions standards "is consistent with CAA section 112 and is a reasonable interpretation of the statute" (See 76 Fed. Reg. 81347). EPA offers very little support for that assertion, however, other than stating its own, often counterintuitive, conclusions. For example, EPA says it "has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards" (See 76 Fed. Reg. 81346). EPA makes little effort to justify that assertion. EPA's statement that "[t]here is nothing in CAA section 112 that directs the agency to consider malfunctions in determining the level 'achieved' by the best-performing or best controlled sources when setting emission standards," (See 76 Fed. Reg. 81326), has it backward. There is nothing in CAA section 112 that allows EPA to ignore malfunctions and set MACT standards based on a level of emissions that even best-performing sources only achieve part of the time.

EPA likewise offers a backwards, results-driven rationale for ignoring malfunctions, which directly contravenes congressional intent that MACT "floor" standards be based on what the best sources actually achieve: "accounting for malfunctions could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source" (See 76 Fed. Reg. 81347). EPA cannot ignore the requirement that MACT "floor" standards reflect performance actually achieved, just

because EPA would like the standards to be more stringent than that actual performance reflects.

EPA acknowledges that even properly designed and operated equipment will sometimes exceed emission limitations that were based on steady-state operation, due to malfunctions (See 76 Fed. Reg. 81347). Even the best-performing units in the source category covered by the Proposed Rule (like any technologies), are subject to a wide variety of potential malfunctions (e.g., power failures, equipment breakdowns) (See 76 Fed. Reg. 81346). The operators of these processes and equipment must treat malfunctions as very distinct events from steady-state operations, depending on the severity of the malfunction, requiring anything from shutdown of the unit to emergency fire response actions. AF&PA agrees with EPA's conclusion that the factual complexity of differing processes and of the severity, frequency, and duration of malfunctions makes standard-setting difficult (See 76 Fed. Reg. 81346). In addition, it is often infeasible to gather emission data during malfunctions – either for standard-setting or for compliance-demonstration purposes. Malfunctions are by definition unexpected and infrequent, so it is not possible to plan to have test equipment in place to measure emissions when one occurs. Even if test or monitoring equipment is in place, emissions during malfunctions often are not routed to a stack where they can be measured, and upsets during stack testing invalidate the test results under EPA's approved test methods.[41]

Rather than supporting EPA's decision to ignore the fact that SSM events can lead to higher emissions even at well-operated facilities with the best control equipment, these findings should lead EPA to its authority under CAA section 112(h) to prescribe alternative design, equipment, work practice or operational standards where it is not feasible to set or enforce a numerical emission limit. EPA cannot rationally defend its articulated view that applying the concept of "best performing" is inconsistent with a source experiencing a malfunction (See 76 Fed. Reg. 81346). This ignores that there are work practices – such as monitoring operating parameters to identify a malfunction and stopping or cutting back the process accordingly – that represent the best practices for minimizing emissions during a malfunction. While the measures that represent these best practices will depend on facility-specific issues, such as process design, pollution control train, and other factors, they nonetheless represent "the maximum degree of reduction in emissions of the hazardous air pollutants...achievable...through application of measures, processes, methods,

[41] EPA acknowledged these potential obstacles to measuring emissions during SSM events in the preamble to final emission standards for medical waste incinerators, (See 74 Fed. Reg. 51368, 51394 (Oct. 6, 2009)): ("It would be very difficult to do any meaningful testing during such an event because the exhaust flow rates, temperatures, and other stack conditions would be highly variable and could foul up the isokinetic emissions test methods (thus invalidating the testing).")

systems or techniques" and reflect "the emission control that is achieved in practice by the best controlled similar source[s]" CAA § 112(d)(2) and (3).

EPA claims that it somehow "presents significant difficulties" to attribute malfunctions to a "best performing" source (See 76 Fed. Reg. 81346). To the contrary, it "presents significant difficulties" when EPA ignores the undisputed existence of malfunctions even at best-performing sources, and claims falsely that the best performing sources "achieve" emission levels that they undisputedly do not achieve part of the time. Since EPA describes malfunctions as being sometimes unavoidable or "not reasonably preventable," despite proper design and maintenance of equipment, there is no basis for EPA's conclusion that malfunction events are not representative of best-performing sources (See 76 Fed. Reg. 81346). True, one goal (although not "*the* goal") "of best performing sources is to operate in such a way as to avoid malfunctions of their units" (See 76 Fed. Reg. 81347). But that is all the more reason why EPA must acknowledge the fact that those sources nevertheless experience malfunction events, rather than assume those emissions away.

By proposing MACT standards that EPA recognizes even the best-performing existing sources cannot achieve part of the time, EPA is going beyond the MACT "floor", yet without making the demonstrations that the statute and case law require the Agency to make in order to impose beyond-the-floor MACT standards. This is especially obvious when one considers the multitude of conditions EPA proposes to impose on sources during malfunctions, in order to be excused from civil penalties: EPA makes no attempt to justify those conditions as reasonable "taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements…." See CAA section 112(d)(2).

Nor does EPA present any substantiation for its belief that "[a]pplying the concept of 'best controlled' or 'best performing' to a unit that is malfunctioning presents significant difficulties" in setting CAA section 112 standards (See 76 Fed. Reg. 81346). It is indefensible for EPA to acknowledge that malfunctions are inevitable, even for the best performing sources, and yet refuse to include emissions data representing malfunctions in calculating the MACT "floor" (See 76 Fed. Reg. at 81346), and then require that those MACT "floor" limitations be met even during malfunctions.

If it is possible to gather sufficient representative data reflecting emissions during malfunctions, then EPA is obligated to consider those data in its MACT "floor" calculations for steady-state operating conditions. To the extent EPA had access to continuous monitoring data for emission units covered by the NESHAP, EPA could

have conducted analyses of emissions levels during malfunction events.[42] Also, many types of sources are required by many state agencies to submit deviation reports or malfunction reports when they experience a malfunction that causes an exceedance of an applicable limitation. EPA does not appear to have made any attempt to obtain and analyze such reports, in order to assess what type of requirement might reasonably apply to the subject emission units during malfunctions.

There are several options EPA could use for setting MACT standards under CAA section 112 that would apply during malfunction events. For example, EPA might be able to establish an emission limitation that applies at all times, but that has an averaging time of sufficient duration that short, infrequent spikes in emissions due to malfunctions would not cause the source to exceed the emission limitation (while at the same time ensuring that the source does not operate in a way that causes frequent, lengthy excursions above the normal controlled emission rate). EPA also could use the flexibility accorded by CAA section 302(k) (defining "emission limitation" and "emission standard" to include "any requirement relating to the operation or maintenance of a source to ensure continuous emission reduction, and any design, equipment, work practice or operational standard promulgated under" the CAA) to address emissions during malfunction events through operational requirements rather than by applying the same limits on pollutant concentrations in exhaust gases that apply during normal operations. EPA could have concluded, as explained above, that it has grounds to exercise its authority under CAA section 112(h) to promulgate a design, equipment, work practice, or operational standard, or combination thereof, because it is not feasible to prescribe or enforce an emission standard. EPA might also use several of these approaches in combination.

There is no indication in the Proposed Rule that EPA gave much, if any, consideration to these types of options. In short, there are ample reasons to reject EPA's conclusory assertions that it cannot take malfunctions into account when setting MACT standards for the subject source category. EPA's failure to evaluate these options thoroughly renders the Proposed Rule arbitrary and requires EPA to develop a new proposal.

[42] Even if the continuous monitoring data are for parameters not regulated by the Proposed Standards, analysis of monitoring data for those other parameters during malfunction events might form a reasonable basis for EPA's assessment of what standards are achieved or achievable during malfunctions.

E. The Proposed Affirmative Defense Is Not a Substitute for Addressing Malfunction Events in the Emission Standards Themselves

EPA acknowledges that the sources subject to the NESHAPs covered by the Proposed Rule sometimes will be unable to comply with the Proposed Standards because of malfunctions, even if their equipment is properly designed and maintained, through no fault of the source (See 76 Fed. Reg. 81347). Rather than promulgate an emission standard that eliminates that situation, so that the regulated emission sources will be subject to differentiated requirements, achievable with the identified best technology during malfunction events, EPA offers instead an "affirmative defense." The proposed affirmative defense shifts the burden to the source to prove that a myriad number of criteria are met and actions were taken by the source (which criteria bear no direct relation to the statutory factors for MACT standards under CAA sections 112), in order to avoid "civil penalties." Inclusion of the affirmative defense does not cure EPA's failure to set emission standards that are achievable during SSM events. The Proposed Standards, incorporating the affirmative defense, still do not represent emission limitations "achieved" by best-performing existing sources under CAA section 112(d)(3), nor do they meet the criteria for establishing beyond-the-floor emission standards under CAA section 112(d)(2).

It is unclear where EPA finds the legal authority in the CAA to shift the burden to the regulated community of proving (or disproving) essential elements of an alleged violation. The statute is silent as to the issue and "the ordinary default rule [is] that plaintiffs bear the risk of failing to prove their claims." *Shaeffer v. Weast*, 546 U.S. 49 (2005), *quoting* McCormick on Evidence §337, at 412 ("The burdens of pleading and proof with regard to most facts have and should be assigned to the plaintiff who generally seeks to change the present state of affairs and who therefore naturally should be expected to bear the risk of failure or proof or persuasion"); C. Mueller & L. Kirkpatrick, Evidence § 3.1, p. 104 (3d ed. 2003) ("Perhaps the broadest and most accepted idea is that the person who seeks court action should justify the request, which means that the plaintiffs bear the burdens on the elements in their claims"). While the Supreme Court has recognized exceptions such as affirmative defenses, courts retain the authority to establish such rules unless Congress acts to delegate that authority.

In this instance, EPA has not provided any statutory authority, nor any real justification, for requiring a source to prove its innocence, including fully demonstrating its innocence within 45 days of the event, without even being charged. Rather, if EPA adopts an approach along the lines of the proposed affirmative defense, it should be

stated instead in terms that, once a source has claimed that its excess emissions were related to a malfunction, it will not be considered to be in violation of the standards unless the enforcement authority demonstrates that the source is not entitled to claim the malfunction.

In addition, having determined to include an affirmative defense in the Proposed Rule, EPA offers no defensible rationale for excluding startup and shutdown events from the proposed affirmative defense. As noted above, EPA has for decades recognized in NSPS regulations that it may not be possible for a source to meet normally applicable emission limitations, even using the best demonstrated technology, during startup, shutdown, and malfunction events. . During periods of startup and shutdown the process is inherently more variable due to changes in operating conditions required as part of the startup and shutdown sequence. If EPA persists in its proposal not to provide less-stringent separate emission limitations for startup and shutdown of the regulated units, and if in fact excess emissions from those units cannot reasonably be avoided during a startup or shutdown, not because of failure of a process or equipment but because of the nature of conditions while starting up or shutting down the source, there is no rational basis for EPA not to provide the same kind of affirmative defense that it proposes to provide for malfunctions.

Even if the proposed affirmative defense was not unreasonably restrictive, as discussed in the following portion of these comments, being able to assert a defense obviously is not the same as complying with emission limitations that are properly set in accordance with CAA section 112. Even though a source believes it qualifies for the affirmative defense, it may be considered to have violated the standards—and may have to report violations, certify noncompliance, etc.—until there has been an enforcement proceeding and the source has successfully asserted the affirmative defense. The affirmative defense places the source in the position of proving its innocence, rather than EPA or another enforcement authority having to prove that the source violated the CAA.

Furthermore, it is not even clear what the affirmative defense covers. In the Proposed Rule, EPA states that the affirmative defense is "to a claim for civil penalties for exceedances of such standards that are caused by malfunction, as defined in § 63.2."[43] Is the term "civil penalties," which is not defined in the Proposed Rule, intended to apply as well to a "civil administrative penalty" imposed by EPA under CAA section 113(d)? (The term "civil penalty" in other contexts means only penalties imposed by a court.) Does the affirmative defense apply to "noncompliance penalties"

[43] Proposed 40 C.F.R. § 63.456

under CAA section 120 (which apply, *inter alia*, to noncompliance with a section 112 NESHAP)? To meet the purported purpose of the affirmative defense, which is to provide relief from emission limitations that cannot be met at times even with equipment that is properly designed and maintained (see 76 Fed. Reg. 81347), the affirmative defense would need to apply to civil and administrative penalties, including noncompliance penalties.[44]

It is unclear as well how the affirmative defense would apply to enforcement actions by state and local governments, or to private citizen enforcement actions under CAA section 304. The preamble to the Proposed Rule, for example, speaks only in terms of application of the affirmative defense in an EPA enforcement action.[45] An affirmative defense should clearly state that it is applicable to enforcement actions by states or citizen-suit plaintiffs, as well.

The Proposed Rule states that: "The affirmative defense shall not be available for claims for injunctive relief." Proposed § 63.456. EPA does not give any explanation for why the affirmative defense would not apply to injunctive relief. If in fact the excess emissions associated with the equipment or process failure are not reasonably preventable, then there is no apparent reason why an affirmative defense to a claim for injunctive relief should not be available, as well. In fact, as a matter of law, injunctive relief may not be available in cases where a civil penalty cannot be imposed. See *Sierra Club v. Otter Tail Power Co.*, 615 F.3d 1008 (8th Cir. 2010) (under concurrent remedy doctrine, injunctive relief for a CAA violation is barred when civil penalty is barred by statute of limitations).

Maintaining liability for injunctive relief renders the affirmative defense particularly ineffective with respect to citizen suits. If the source is even potentially subject to injunctive relief, and therefore could be required to pay the citizen-plaintiff's attorneys fees even if the source successfully demonstrated that it otherwise qualified for the affirmative defense, then the affirmative defense would not accomplish EPA's stated objective of providing relief in situations where the emission limitations cannot be met despite proper design and operation of process and control equipment.

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[44] In the preamble to the Proposed Rule, EPA states that, if a source cannot prove its entitlement to the affirmative defense, "appropriate penalties could be assessed in accordance with section 113 of the CAA (see also 40 CFR 22.27)" (See 76 Fed. Reg. 81347). This does not answer the questions stated above. The Proposed Rule, therefore, is unclear on this key issue of what the affirmative defense is intended to cover.

[45] See 76 Fed. Reg. 81347 ("In any judicial or administrative proceeding, the Administrator would be able to challenge the assertion of the affirmative defense….") (emphasis added).

EPA has not addressed these and other apparent limitations and shortcomings of the affirmative defense, which make it an entirely inadequate substitute for setting MACT standards that include provisions for SSM events. Moreover, EPA has provided no analysis that would supersede its long-standing determination that it is not desirable to rely on enforcement, rather than regulatory language, to address the inability to comply with technology-based standards during SSM events (See 37 Fed. Reg. 17214, (Aug. 25, 1972)) (establishing SSM provision in NSPS). The courts have adopted the same view. See, e.g., *National Lime*, 627 F.2d at 431 n.46 ("the flexibility appropriate to enforcement will not render 'achievable' a standard which cannot be achieved on a regular basis, either for the reasons expressly taken into account in compliance determination regulations (here startup, shutdown and malfunction), or otherwise.").[46]

At a minimum, then, EPA should state that the affirmative defense applies to civil penalties, civil administrative penalties, noncompliance penalties, and injunctive relief, in an action brought by EPA, a state, or a citizen-suit plaintiff. EPA also should reword the "affirmative defense," so that it states that a source "will not be deemed in violation of" the MACT standards for excess emissions or other deviations from the standards, associated with a startup, shutdown, or malfunction event, unless the event, and the source's response to the event, do not meet the criteria spelled out in the regulations.[47] Configured in that way, this provision for malfunction should be called something other than an "affirmative defense," such as an "alternative standard for SSM events."

F. The Proposed Affirmative Defense As Written Is Unreasonable and Impracticable

If EPA refuses to set alternative emission standards that apply during SSM periods and continues to rely instead on the proposed affirmative defense, the affirmative defense must be substantially modified for it to provide any significant relief. First, as noted above, the affirmative defense needs to state clearly that a source that qualifies for the affirmative defense shall not be deemed to have violated the applicable standards during that time. If EPA does that, it may be unnecessary to state also that the

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[46] See 37 Fed. Reg. 17214 (Aug. 25, 1972) (establishing SSM provision in NSPS). See also *Marathon Oil Co. v. EPA*, 564 F.2d at 1273 (explaining why EPA's statement that it would not take enforcement action against sources that exceeded effluent limitations because of upset events was "not an adequate response" to the argument that standards that cannot be met during unavoidable upsets fail to reflect available technology). Also for these reasons, EPA's statements in the Proposed Rule preamble that EPA will "determine an appropriate response" to reported exceedances of the Proposed Standards, based on whether the exceedances were avoidable, minimized, etc. (which seems to be in addition to providing the affirmative defense) are not in any way a substitute for EPA setting the standards at an achievable level to begin with (See 76 Fed. Reg. 81347).

[47] *Compare, e.g.*, 40 C.F.R. § 80.613 (stating that persons demonstrating specified defenses "will not be deemed in violation" and are not "deemed liable for a violation" of diesel fuel sulfur program regulations).

affirmative defense relieves the source from liability for all types of penalties and injunctive relief (save criminal penalties), but that should be the clear effect of qualifying for the affirmative defense.

The affirmative defense should be available not only for malfunctions, but also for excess emissions during startup and shutdown. There is no logical reason why a source that experiences excess emissions during startup or shutdown that were not reasonably preventable (either because the source experienced conditions EPA did not anticipate in setting the standards, or because EPA's assumption about the achievability of those standards during startup and shutdown periods was wrong) should be excluded from the affirmative defense.

Additionally, many aspects of the affirmative defense would make it unavailable as a practical matter for many, if not most malfunctions. EPA needs to substantially revise and streamline the proposed affirmative defense for it to be of practical value.

Several of the conditions for establishing an affirmative defense in proposed 40 C.F.R. § 63.456(a) list numerous items which may be appropriate considerations in determining whether excess emissions during a malfunction should be considered a violation, but which ought not to be listed as mandatory criteria, all of which have to be met in order for a source even to raise an affirmative defense. For example, proposed § 63.456(a)(1)(i) requires that the excess emissions must have been "caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner…." There is no apparent reason why a "sudden" and "unavoidable" equipment failure or process upset leading to emissions greater than the MACT emission limitation should be considered a violation of the standards if it is not "infrequent," even though it is "not part of a recurring pattern indicative of inadequate design, operation, or maintenance" and "[c]ould not have been prevented through careful planning, proper design or better operation and maintenance practices." See proposed § 63.456(a)(1)(ii)&(iv).

A number of the conditions for establishing an affirmative defense use phrases that are subject to a wide range of interpretations, and that on their face do not recognize any need for reasonableness or cost-effectiveness. How will the enforcement authority, or a judge, determine whether "proper design" or "better operation and maintenance practices" could have prevented a malfunction (§ 63.456 (a)(1)(ii)), whether a recurring malfunction is a result of "inadequate design"(§ 63.456(a)(1)(iv)), whether repairs were made "as expeditiously as possible" (§ 63.456(a)(2)), whether the source took "all possible steps" to minimize the impact of the excess emissions (§ 63.456(a)(5)), *and*

whether emissions control systems "were kept in operation if at all possible"(§ 63.456(a)(6))?

In some cases, it may have been possible to prevent the malfunction, or to have further reduced the excess emissions, if the source had spent huge amounts of money with little emission reduction or had imposed economically impracticable constraints on its operation. The affirmative defense, as proposed, leaves open the possibility that a source will be considered to be in violation because the enforcement authority decides subjectively that in one or more respects it would have been "proper" or "possible" for the source to take further steps to prevent or minimize the malfunction.[48]. In effect, EPA or the court may impose an extreme version of MACT during malfunction periods, without any application of the beyond-the-floor factors in CAA section 112(d)(2). At a minimum, the vague and unqualified descriptors in the criteria for demonstrating the affirmative defense will inevitably lead to varying conclusions as to whether a violation has occurred, resulting in inconsistency from one jurisdiction to the next.

Proposed § 63.456(a)(6) requires, as a condition for the affirmative defense, that all emissions "control systems were kept in operation if at all possible." The phrase "if at all possible" should not be used because it is an extreme term that bears no relation to good air pollution control practices. Additionally, this provision should be qualified, as EPA has qualified similar provisions in the NESHAP General Provisions in 40 C.F.R. § 63.6. For example, these conditions should be qualified with caveats that the operation must be consistent with safety and good air pollution control practices, that it does not require the source to make further efforts to reduce emissions below what the standards require, and that it does not require regular operation of backup or standby pollution control equipment.[49] In an analogous setting, EPA has long recognized, in the General Provisions applicable to NSPS, that it is appropriate to require sources to operate the affected facility and related air pollution control technology "to the extent practicable…consistent with good air pollution control practice for minimizing emissions" during SSM periods, not "if at all possible." See 40 C.F.R. § 60.11(d)); see also, e.g., 40 C.F.R. § 63.480(j)(4) (during SSM events, Group I Polymer & Resin plants are required to use "to the extent reasonably available, measures to prevent or minimize excess emissions to the extent practical."). EPA cannot abandon those rational approaches and adopt the kind of absolute requirements implied by the

[48] In contrast, EPA has included provisions in other NESHAPs explicitly recognizing that back-up control devices are not required. See, e.g., 40 C.F.R. § 63.480(j) ("Back-up control devices are not required, but may be used if available.").

[49] EPA also determined it was appropriate to include those kinds of caveats in its regulation requiring proper operation and maintenance of wastewater treatment facilities, in 40 C.F.R. § 122.41(e).

Proposed Rule, without an explanation of why it is necessary and appropriate to do so. Indeed, EPA recently agreed to insert language in several NESHAPs to clarify that the general duty to minimize emissions "does not require the owner or operator to make any further efforts to reduce emissions if levels required by this standard have been achieved" (See 76 Fed. Reg. 22566, 22583, col. 3 (April 21, 2011)).

Proposed § 63.456(a)(4) would preclude a facility from taking advantage of the affirmative defense if the malfunction involved bypassing control equipment or a process and the bypass was not "unavoidable to prevent loss of life, severe personal injury, or severe property damage." This language is stated in such strong terms that it may be difficult or impossible for a source to demonstrate that it meets this criterion, even though bypassing the control equipment or the process was an appropriate exercise of good air pollution control practices. For example, a bypass can constitute the best air pollution control practice in response to an upset in order to prevent excess emissions, e.g., to avoid fouling of pollution control equipment media that in turn would result in reduced pollution control equipment efficiency or increased pollution control equipment downtime. There can be substantial room for disagreement about what constitutes "severe" property damage. And what degree of injury to employees must the bypass avoid in order to qualify as avoiding "severe" personal injury? Besides the unclear and subjective nature of these criteria, there is nothing inherent to standards under CAA section 112 that requires a source to avoid bypassing control equipment to such a degree. Lastly, it is not apparent, and EPA has not attempted to explain, why the CAA would disfavor bypassing "a process" in this way.

Under proposed § 63.456(a)(5) a source claiming the affirmative defense must prove that: "All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health." In addition to the subjective term "all possible steps," this provision again presents a disconnect between the absolute and extreme requirement of the affirmative defense and the provisions of the CAA designed to attain ambient air quality standards and protect human health and the environment. The CAA does not require sources to take "all possible steps" to control emissions, even to minimize the impact of hazardous air pollutant emissions on human health under CAA section 112(f). In addition, it is unclear how this criterion for qualifying for the affirmative defense differs from proposed § 63.456(a)(3) which requires that the frequency, amount, and duration of excess emissions "were minimized to the maximum extent practicable." Unless EPA explains what additional showing would be needed by § 63.456(a)(5), that paragraph should be eliminated.

The requirement in proposed § 63.456(a)(9) that the source "have prepared a written root cause analysis to determine, correct and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue" again does not implement the statutory criteria for standard-setting under section 112. Moreover, read literally it would mean that a source could never take advantage of the affirmative defense if the source was unable to determine the primary cause of the malfunction or was unable to correct that cause. EPA has defined a malfunction as an event that is "unavoidable" and unforeseeable, and "not reasonably preventable." See proposed § 63.456(a)(1)(ii)&(iii)and 40 C.F.R. § 63.2. It therefore should be expected that in many cases the primary cause(s) of the malfunction will not be ascertainable, or it will not be possible to identify a way to ensure the malfunction will not recur.[50] In addition, requiring the facility to eliminate the primary causes of the malfunction, without regard to "taking into consideration the cost of achieving such" elimination and the "non-air quality health and environmental impacts and energy requirements" associated with its elimination is unreasonable and entirely inconsistent with the criteria for standards established under CAA section 112(d).[51]

Finally, the requirement in proposed § 63.456(b) to notify the Administrator by telephone or fax as soon as possible, but no later than two business days after the malfunction begins, and then to submit a written report within 45 days of the initial occurrence of the malfunction that demonstrates, "with all necessary supporting documentation," that the source met all of the multitude of criteria for the affirmative defense, is unreasonable and unnecessary. It is novel at best for a person to be determined to have acted unlawfully unless the person has submitted his entire defense before he is even notified of a potential enforcement action. In many cases, it would be obvious to the enforcement authority, based on the kind of short malfunction or deviation report sources already submit under many air programs, that an exceedance of the Proposed Standards resulted from an unforeseen and unavoidable equipment failure or process upset. It is extremely inefficient and burdensome, for both

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[50] EPA has long acknowledged this reality in the General Provisions applicable to NSPS, which requires that written reports of excess emissions include the "nature and cause of any malfunction, if known…." See 40 C.F.R. § 60.7(b)(2) (emphasis added). It would be arbitrary and capricious for EPA not to include similar language here.

[51] For example, it might be theoretically possible to eliminate the excess emissions associated with the malfunction by installing totally redundant pollution control equipment, or pollution control equipment with far more capacity than needed for normal operations. But this would not reflect the performance of the best performers on which the MACT "floor" is to be based, nor would it appear to take cost and other factors into consideration as the statute requires for beyond-the-floor MACT standards. Moreover, the proposed requirement to eliminate "the primary causes of the malfunction" and not just to eliminate "the excess emissions resulting from the malfunction event" lies entirely outside of EPA's authority under the CAA, which is limited to establishing and enforcing emission limitations, not dictating plant operations.

sources and regulators, to require a complete justification of the affirmative defense before the enforcement authority has indicated any need for further investigation.

Since the affirmative defense is only available if all criteria are met, including the 48-hour and 45-day notifications, and since sources will have no way of knowing whether there might be an enforcement action or citizen suit at some point in the future addressing the period affected by a malfunction, sources will need to submit notifications of the malfunction, with all the supporting documentation, whenever a malfunction defense could be claimed. This will swamp EPA and state agencies with unnecessary paperwork, and for no clear benefit. (Note that, if EPA ultimately were to conduct a rulemaking to eliminate the excess emission provisions discussed in Section V above, despite AF&PA's arguments for retention of those provisions, there would be even more oral and written reports under the proposed affirmative defense. As explained above, the events covered by the excess emissions may occur often and, although they may last only a few minutes, a mill would have no way of knowing whether those incidents might later be part of an enforcement action, so the mill may feel compelled to report each of them under the affirmative defense notification requirements.)

AF&PA notes that EPA recently proposed almost identical affirmative defense requirements in its proposed reconsideration of various provisions of the Chemical Manufacturing Area Source Rule (see 77 Fed. Reg. 4522, January 30, 2012), but omitted the 2-day notification requirement. AF&PA hopes this indicates that EPA has been persuaded by comments submitted by the SSM Coalition (of which AF&PA is a member) and others that the 2-day notification requirement is onerous and burdensome. AF&PA also understands that EPA may be revisiting some of the other requirements in the affirmative defense provisions in order to further reduce the burden on facilities. AF&PA requests that, at a minimum, EPA abandon the 2-day notification requirement in the final pulp and paper RTR rule, consistent with its proposal for the provisions for Chemical Manufacturing Area Source Rule.

Additionally, allowing only 45 days to provide the kind of extensive documentation required by the affirmative defense as currently written, including a completed root cause analysis, is unreasonable. As we pointed out above, EPA's whole "guilty until proven innocent" approach of requiring complete documentation that an event qualifies for the affirmative defense at the time of the event is unnecessary and burdensome. But if EPA persists in requiring such reporting ninety days is the minimum time that should be allowed for the written report, unless EPA substantially streamlines the criteria for the affirmative defense, consistent with these comments.

Note that the proposed 45-day period for submitting a written report demonstrating that the source qualifies for the affirmative defense commences on the date of "the initial occurrence of the exceedance of the standards." See proposed § 63.456(b). This presents several problems. Much of the required content of that written report could not be created until the malfunction event ceased—which could be many days after the malfunction commenced. For example, if a biological wastewater treatment system stops providing sufficient HAP removal efficiency, it may take days to identify the nature of the problem, and then it could take weeks to reestablish a sufficient microorganism community to again meet treatment requirements. This could make the amount of time the source would have, in practice, to prepare the report much less than 45 days.

Also, the provision in the Proposed Rule for requesting and obtaining an extension of the reporting deadline of up to 30 days would provide little practical relief: the source would have to submit the report within 45 days unless the EPA Administrator (or his or her authorized representative, see 40 C.F.R. § 60.2) granted the extension request before the expiration of the initial 45-day period, which is not likely to happen until shortly before, if not after, the report would otherwise be due. At a minimum, the rule should provide that a request for extension of the reporting deadline that the Agency has not acted on within 10 days is considered granted.

Because of the problems associated with the timing of required reporting described above, AF&PA requests that malfunction reporting be required on a semi-annual basis for malfunctions that occurred during the preceding six months (the same frequency as similar reports pursuant to NESHAPs and Title V permit requirements). This would enable EPA to review the source's compliance history and the measures being taken to address malfunctions without imposing unworkable reporting deadlines (or potentially encouraging sources to bombard the Agency with reports for malfunctions that may not ultimately result in the source exceeding the 30-day average emission limitation). Nowhere has EPA justified departing from its conclusion, reflected in the current Subpart S standards, that semi-annual reporting of malfunctions is sufficient. See 40 C.F.R. § 63.455(a).

G. General Provisions that Should No Longer Be Referenced

In the preamble on page 81346, the Agency requests comments "on whether there are any such provisions that we have inadvertently incorporated or overlooked" in reference to the proposed changes in SSM language. While AF&PA takes issue with the proposed changes as noted above, the organization has reviewed the rule and is not aware of any cases where the proposed rule is inconsistent with the intent of the Agency's actions.

VIII. Other Comments

A. The Proposed Concentration Limit for Condensate Treatment for Bleached Mills Is Inconsistent with the Background Documents

In the preamble to the proposed rule (76 Fed. Reg. 81345) and EPA's memo dated October 23, 2011, Table 2 states that the equivalent concentration for bleached mills is 248 ppmw[52]. However, in the proposed rule, the concentration is listed as 210 ppmw[53]. The proposed rule needs to be modified to be consistent with the analysis in the docket.

B. The New Requirement for Electronic Reporting of all Monitoring Data Is Burdensome and Unnecessary

EPA has included a new reporting requirement in the December 2011 proposed amendments to the rule that will be excessively burdensome to industry. This requirement is not justified. Proposed § 63.455 (h)(2) and (3) states that within 60 days of completing each performance test and CEMS performance evaluation test, the owner/operator must submit the test data to the EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) when the data and methods are compatible with the ERT.

Performance tests conducted under Subpart S are unique and unlike traditional stack tests. The data collected and the standards that must be met are specific to the systems used to collect and treat condensates. There is no reason for EPA to require the submittal of this test data. Facilities are required to submit performance test data to regulatory agencies and provide certifications on their semi-annual compliance reports that they have performed the required monitoring and will provide information on any deviations from the testing requirements. Additional performance test reports provide no useful purpose, environmental or otherwise, to anyone and are an additional administrative burden on operating facilities. The ERT continues to be revised and updated due to various flaws. It is unreasonable to put sources at risk of violations (late reporting) because of EPA reporting tool issues or availability.

.A number of states already specify that performance test results be submitted in an electronic format. EPA should remove its reporting format requirement from the rule and

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[52] Summary of Kraft Condensate Control Technology Review," EPA Memorandum to Docket – EPA-HQ-OAR-2007-0544-0128, John Bradfield and Kelley Spence, October 23, 2011, page 7.

[53] 76 Fed Reg 81354, Proposed Rule § 63.443(4)

work more closely with states to develop a universal reporting system that is not costly or redundant, does not require, different electronic reporting formats, and that is not problematic and labor-intensive for data entry. As proposed, the rule's requirement is an extra, excessive burden for mills and stack testing vendors. EPA needs to defer any electronic collection of data until the CDX and WebFIRE systems are fully functional, user-friendly, and streamlined with States.

C. Compliance Deadline

1. Electronic Reporting Effective Date Is Incorrect

In the preamble to the rule, on page 81349 under "E. Compliance Dates" it states that electronic reporting is "effective upon promulgation of the final rule." However, the revised language of the rule in 40 CFR § 63.335(h)(2), states that "As of January 1, 2012 and within 60 days after the date of completing each performance test, you must submit performance test data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT)..." This language is confusing in that it could be concluded that once the rule is effective, all test reports since January 1, 2012, should have been submitted within 60 days of testing prior to the rule being effective.

2. Compliance Deadline Should Be Three Years for All Rule Changes

In the preamble to the rule, EPA proposes that "existing facilities must comply with all of the requirements in this action (other than affirmative defense provisions and electronic reporting, which are effective upon promulgation of the final rule) no later than three years after the effective date of this rule" (See 76 Fed. Reg. 81349). EPA should not promulgate a final rule containing significant new requirements with two compliance dates, and three years is the appropriate compliance deadline for all new requirements. For example, to eliminate the SSM provisions of the existing rule, which apparently would be effective immediately upon promulgation of the final rule. EPA has not really assessed the effect of eliminating that provision, but it could require mills to make significant changes to their HAP collection and treatment systems, such as installing redundant equipment not currently required, which would take significant time for design, engineering, acquisition, and installation. There would be no justification for making such a change in the existing regulations effective immediately, as EPA has proposed (See proposed sections 63.443(e) and 63.446(g).

D. EPA's Proposed Requirement that the Administrator Specify Test Conditions Is Unreasonable

Proposed section 63.457(o) states that performance tests shall be conducted under "such conditions as the Administrator specifies to the owner or operator based on representative performance of the affected source for the period being tested. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests."

Depending on what "conditions" the Administrator specifies it may be impossible to conduct performance testing in the time frame required, while simultaneously meeting all the conditions the Administrator or her designee may specify. This new provision makes it unnecessarily difficult to develop testing protocols and successfully conduct performance tests. A performance test should be conducted under normal operating conditions, taking into account real-world constraints and considerations. For example, the actual load or capacity to which any digester, pulp washing line, or bleach plant (and their supporting steam stripper or wastewater treatment plant) can operate depends on the capacities of tanks holding pulp and the demand for pulp from pulp and paper machines (unless the pulp is discharged to the sewer, a highly undesirable outcome). A number of other short-term process fluctuations and unplanned events can have an impact on pulp production and supporting operations. Mills provide stack test notice 60 days in advance and plan for stack tests in good faith to run under conditions that represent normal operation. Normal operation includes many load conditions and load mixes at mills with multiple lines. The language in the rule should simply require that performance tests be conducted under normal operating conditions.

Special conditions and alternative operating scenarios (such as running only one scrubber in a series of two scrubbers) are addressed in Part 70 operating permits, which also address the compliance demonstration requirements for these scenarios

IX. Conclusion

AF&PA appreciates the opportunity to submit these comments on the proposed revisions to the NESHAP for the Pulp and Paper Industry. We agree with EPA's conclusions that current risks are acceptable and no advances in controls have occurred. However, we strongly disagree with EPA's proposed changes in the emission limits including the lb/ODTP limits which are based on a misinterpretation of industry data, are very costly (9 to 23 times more expensive than EPA estimates), and not cost-effective as section 112(d)(6) requires. In addition, the excess emission allowances should be retained as essential to the safe operation of mills (we plan to provide more information on venting experiences by June 27, 2012). As a result, EPA should retain the current requirements in Subpart S.

AF&PA stands ready to assist as EPA continues its work on this rule. If you have any questions about these comments or need additional information, please do not hesitate to contact Tim Hunt at 202-463-2588.

Environment

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Review of the HEM3 Modeling Conducted by EPA for the Pulp and Paper Industry RTR

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Review of the HEM3 Modeling Conducted by EPA for the Pulp and Paper Industry RTR

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1.0 Introduction

AECOM, on the behalf of American Forest and Paper Association (AF&PA), conducted a review of the air emissions modeling information used by U.S. Environmental Protection Agency (EPA) in the evaluation of acute and chronic inhalation risk associated with Subpart S MACT sources at pulp & paper mills throughout the U.S. In this evaluation EPA applied an updated and enhanced version of the Human Exposure Model (HEM3) that includes substantive changes to the public version of HEM3 currently posted on the internet and last updated in 2007. Specifically for this assessment, EPA did not apply the public domain version of HEM3 (available at http://www.epa.gov/ttn/fera/hem_download.html) but developed an enhanced version of the program which implements the current version of AERMOD. In applying this updated version of HEM3 that is not available to the public, EPA also applied a more robust set of hourly meteorological data than the sets of metrological data that are presently available on the HEM3 Website. In addition, EPA revised the population-based receptor files in HEM3 to exclude receptors that appear to be on-site and to add receptors in nearby residential areas. While modeling enhancements may be appropriate for EPA to have incorporated into the RTR, EPA's use of this unpublished version of HEM3, along with receptor and meteorological data sets that are not presently in the public domain, prevents AF&PA and paper companies from independently verifying and fully interpreting EPA's risk findings as well as evaluating the effects of possible model corrections and refinements. To help interpret EPA's findings and review modeling data on behalf of AF&PA, AECOM requested and received access to EPA's HEM3 input data for each of the mills modeled for the 2011 draft residual risk assessment. EPA has also shared detailed HEM3 output and data analyses. This review is based on AECOM's and National Council for Air and Stream Improvement's (NCASI) s examination of this HEM3 modeling data.

In addition to the data files provided by EPA, AECOM's review included pertinent reports and memoranda provided by EPA in support of proposed rule for National Emission Standards for Hazardous Air Pollutants From the Pulp and Paper Industry (40 CFR Part 63) published in the Federal Register on December 27, 2011:

- *Inputs to the Pulp and Paper Industry October 2011 Residual Risk Modeling* (RTI, November 11, 2011)
- *Draft Residual Risk Assessment for the Pulp & Paper Source Category* (EPA, December 2011).

AECOM's review focused on information regarding location and characterization of emission sources and placement of model receptors that substantially influence the modeled short- and long-term average modeled concentrations and, in-turn, the associated acute, chronic and cancer risk. These elements are by no means the only elements affecting the modeled risk. NCASI reviewed hazardous air pollutant emission factors and emission rates used in the modeling analysis. Other principal risk assessment elements that were not independently reviewed were dose-response factors applied by EPA in the HEM3 modeling.

This report describes the data and information sources and findings of the modeling review and a brief discussion of EPA's selection of HAPs for the RTR risk assessment.

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2.0 Data and Information Sources

Table 2 of *Appendix 5 Detailed Risk Modeling Results* in the EPA's *Draft Residual Risk Assessment for the Pulp & Paper Source Category* lists each mill according to NEI inventory identifier and the associated modeled lifetime maximum inhalation cancer risk and non-cancer hazard index. These risks represent the highest modeled risk among population-based receptors (2000 census block centroids with some modifications and additions) used in HEM3. From this list, all 42 of the mills with Subpart S source category modeled cancer risk of two chances in a million and greater were selected for review. These 42 mills include all of the mills with a chronic hazard risk of 0.22 and greater. Table 3 of *Appendix 5* provides the maximum predicted acute modeled with HEM3 by applying a factor of 2 to estimate maximum hourly emissions from annual emissions. The modeling information for the nine mills with modeled acute hazard quotients exceeding 1.5 was also reviewed.

EPA also provided AF&PA access to the detailed HEM3 modeling files for each of the mills. The review included the following types of information:

- *GoogleEarth™* kmz files displaying sources and population-based receptors and the maximum impact receptor. As illustrated in Figures 1 and 2, clicking on a receptor provides a pop-up box with the modeled cancer risk or hazard index, depending on the layer chosen and associated HAP contributions.
- A large access database file containing the HEM3 source input information for all mills
- A variety of HEM3 output in DBF files (readable in Excel) and Excel spreadsheets containing source data, maximum modeled risks by HAP and source as well as total population risk.

The complete list of HEM3 file names and a description of their contents is provided in Table 1.

Table 1: Key HEM3 Data Spreadsheets

File Name	Description
acute_breakdown	maximum 1-hour concentration per HAP and Source
acute _chem_pop	total maximum 1-hour concentration per HAP and benchmarks at population receptors
acute_chem_unpop	total maximum 1-hour concentration per HAP and benchmarks among all receptors
all_polar_receptors	HAP concentations at all polar receptors
allreceptors_risk	Google Earth kmz file
cancer_risk_exposure	individual cancer risk levels and corresponding population exposed
incidence	lifetime cancer incidence for each HAP and source
maximum_indiv_risks	maximum cancer risk, chronic HI and toxic organ specific HI at population receptors
maximum_offsite_impacts	maximum cancer risk, chronic HI and toxic organ specific HI among all receptors
noncancer_risk_exposure	total chronic HI levels and corresponding population exposed
ring_summary_chronic	cancer risk and chronic His at each ring receptor
Final NEI-HEM3 Emission Inventory Crosswalk	listing of source parameters and HAP emissions used in HEM3

For each mill the focus of the review of modeling information focused on the following model input considerations:

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- HEM3 parameter data base was filtered to select the appropriate mill and its Subpart S sources.
- The source parameters were examined in terms of source type, location, number of sources, height, release temperature, diameter for point sources; length, width, and angle from true north for area sources.
- The corresponding “kmz” files were opened to review the source locations, extent and orientation of area sources and location of receptors used to compute chronic hazard index and cancer risk.

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Figure 1: Example *GoogleEarth™* kmz File Displaying Cancer Risk

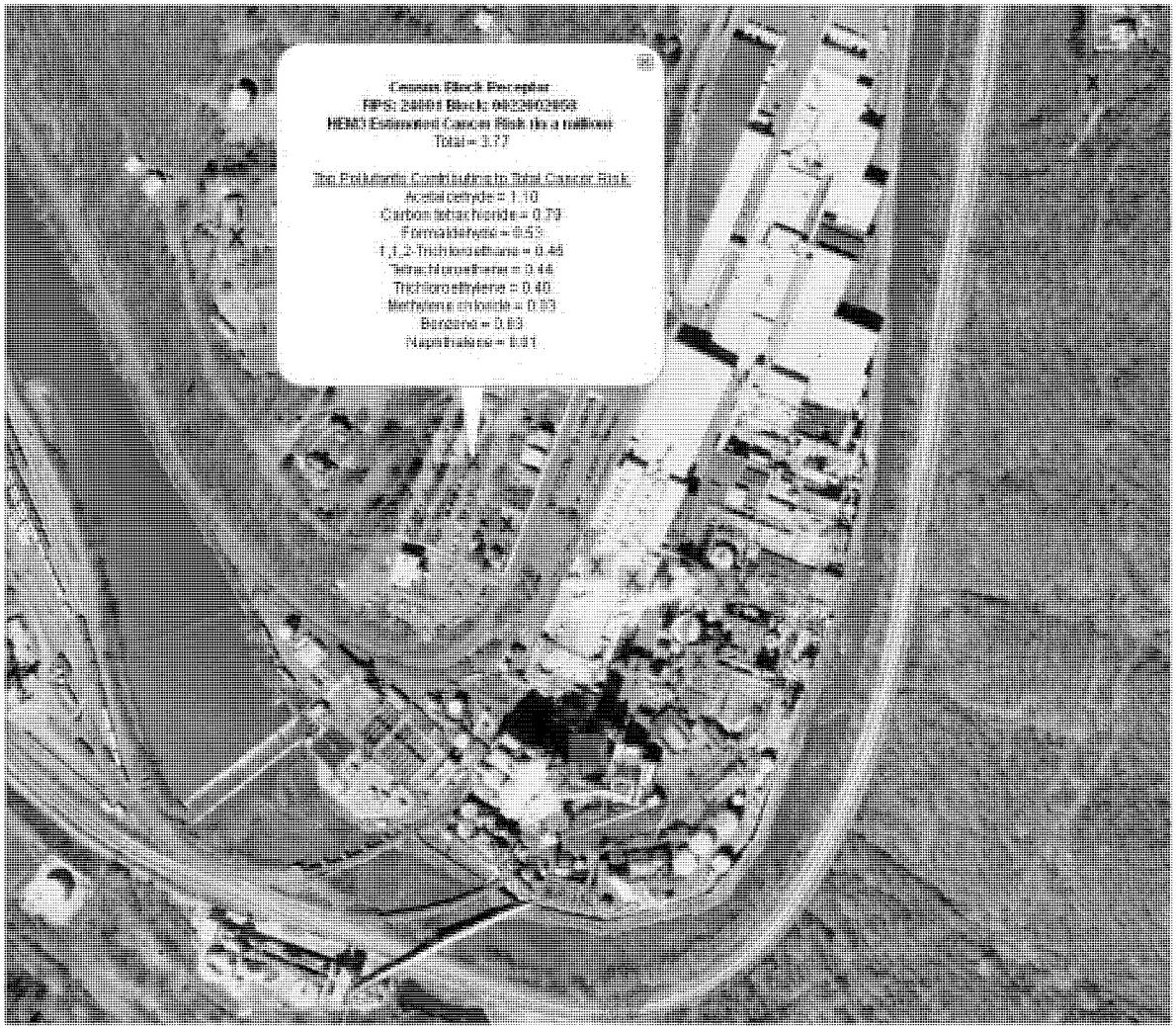
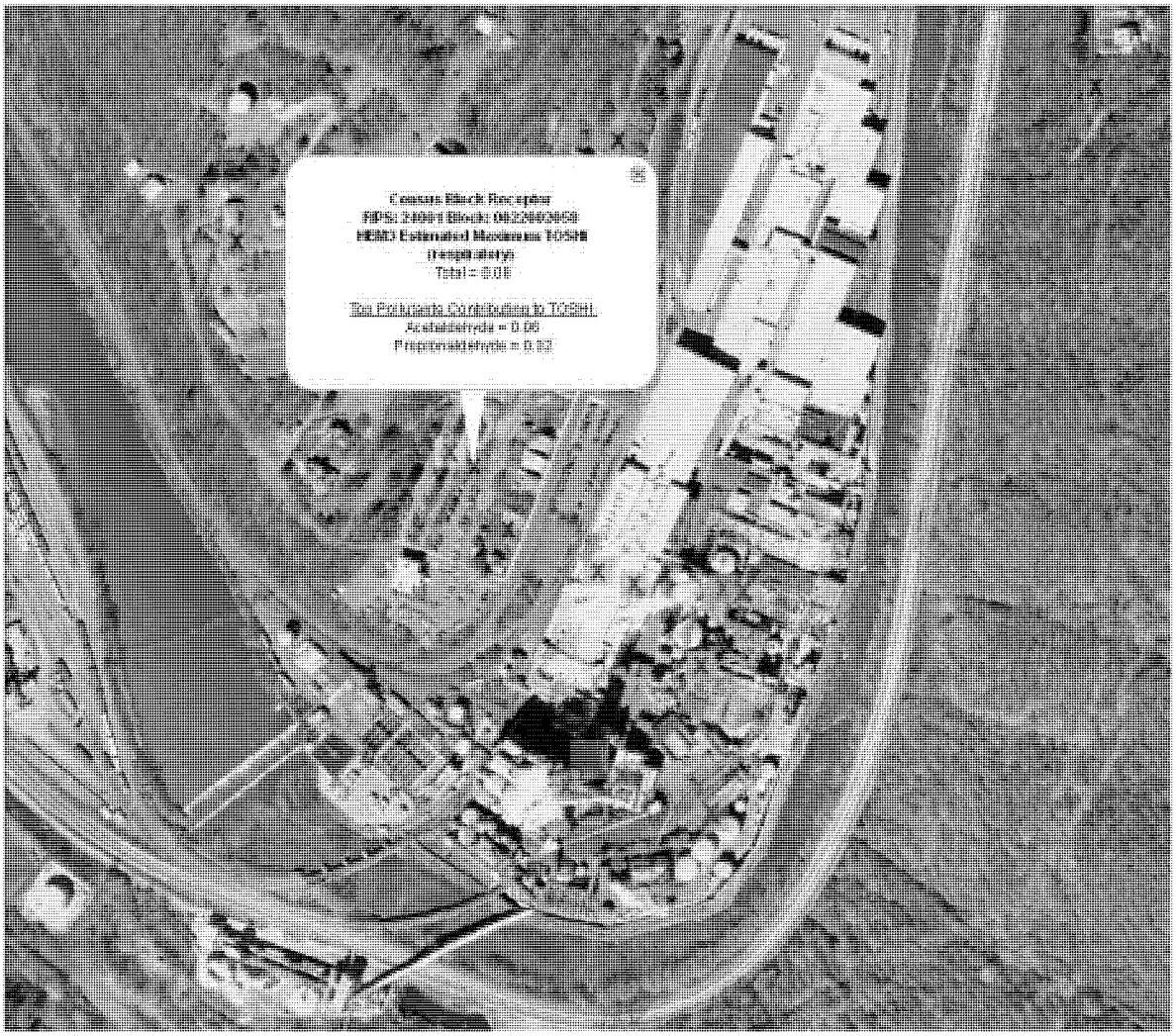


Figure 2: Example *GoogleEarth*™ kmz File Displaying Hazard Index



3.0 Results of the Modeling Review

The results of the review are summarized in Tables 2 and 3 for all 42 facilities assessed that had a Subpart S chronic modeled inhalation risk greater than or equal to 2 in a million and the 9 facilities assessed with acute non-cancer health effects, respectively. It is AECOM's conclusion that EPA has applied suitable modeling tools for the RTR assessment and the use of the ICR data has improved the accuracy of dispersion modeling and risk estimates from earlier EPA assessments. However, limitations and errors in the input data still exist and affect the ability of the RTR assessment to accurately characterize maximum off-site risk. Experience in dispersion modeling has shown that in the vast majority of cases, a more accurate and detailed characterization of emissions sources results in lower, more realistic risk estimates. As noted, AECOM's ability to independently verify EPA's modeling, and to assess the effects of improving the input data is limited because the risk assessment platform used by EPA is not in the public domain and has not been made available by EPA.

In the RTR risk assessment, EPA incorporated information provided by mills in response to the recent Information Collection Request (ICR). It has been relayed to AECOM through NCASI that there are instances that a mill's source characterization used in the RTR may not match the information in the ICR submittals. Although we do not know the extent to which this is the case or the contributing factors, it is acknowledged that if the mill emissions are characterized in a simplistic fashion, such as combining all emissions into a single source, the resultant concentrations and associated risks will be overestimated. A detailed examination of the modeling data used by EPA for mills with greater modeled risk identified some of the same issues previously encountered by AF&PA and discussed with EPA during the review of National Emissions Inventory (NEI) data.

The following is a description of the model input parameters that were found to be in error, among the mills with higher modeled risk. It is expected that these types of errors are common among all of the mills and thereby may contribute to a general overestimation of modeled risk from this industrial sector.

- In EPA's assessment of the potential health effects due to long-term inhalation exposure from Subpart S sources, 42 mills had a modeled maximum individual lifetime cancer risk of 2 chances in a million or greater. Predicted hazard indices for all mills were less than 1 for Subpart S sources. For the 42 mills , the following observations can be made:
    - Risks at more than 64 % of these mills (27 of 42) are primarily associated with emissions from mill sources characterized as area sources, simplistically representing a large number of discrete emission sources. In dispersion modeling it is commonly found that a more detailed source characterization materially reduces modeled concentrations and associated modeled maximum off-site risk. This is largely because modeling as area sources inherently assumes that all emissions in the area are released at a single height and no credit is given for plume rise associated with individual point sources.
    - About 17% of the mills (7 of 42) were characterized as single point emission sources or with consolidated releases emitted from only a few points. This simplistic method insufficiently characterized the spatial distribution of source

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emissions at the mill, and would be expected to result in overestimates of off-site concentrations and associated risk.

- About 26% of the mills (11 of 42) had incorrectly located one or more of the sources that contributed substantially to the modeled risk. It is expected that more accurately locating these sources would result in lower modeled risk.
- Three of the 42 mills had maximum modeled risk at a population-based receptor that was erroneously placed in an uninhabited and inaccessible location close to a major emissions source.
- About 26% of the mills (11 of 42) had erroneously calculated emissions, input the total facility emissions for a category into multiple sources rather than the contribution of each source, or used an emission factor based on questionable data. It is expected that more accurately locating these sources would result in lower modeled risk.
- About 19% of the mills (8 of 42) had characterized sources with very low or default fugitive release heights. This simplistic method insufficiently characterized the dispersion of these source emissions at the mill, and would be expected to result in overestimates of off-site concentrations and associated risk.

Appendix A has Google Earth images for all of the 42 mills listed in Table 2.

- In EPA's refined assessment of the acute risk of Subpart S sources, four HAPs, acetaldehyde, formaldehyde, methanol, and chloroform, contribute to acute HQs >1.5. at nine mills. All modeled acute off-site HQs for these nine mills are due to modeled area sources and for seven of the mills the impact is due to wastewater sources of which four are incorrectly located.

In addition, several mills have notified AF&PA that the input data utilized in EPA's risk assessment were incorrect. Those mills intend to submit corrected or updated data to EPA. Examples of needed corrections include the following:

- HEM3 input data were off several orders of magnitude due to either mistakes in the NEI submittals or transcription errors from the NEI to the HEM3 model
- Updated NEI emission estimates based on revised bleached paper machine emission factors issued by NCASI[1] in late June 2011were not submitted to EPA
- Unrepresentative meteorological data were used in the HEM3 assessment

Appendix B lists the mills that have or will be submitting corrections to EPA.

[1] The National Council for Air and Stream Improvement (NCASI) is an independent, non-profit research institute that focuses on environmental topics of interest to the forest products industry.

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Table 2: Source Category Chronic Risk

Facility NEI ID	Cancer MIR	Non-cancer Max HI	Risk Driver (% of Risk)	Risk Driver Source Group(s)	Comments on Source Contribution and Characterization
21091NEI32869A	**1.21E-05**	0.17	Hexachloroethane (80%)	Kraft Pulp Storage	Area Sources HCE emissions were estimated from a trade group emission factor based on limited and questionable data, the majority of which was non-detect. (configuration appears realistic)
01023NEI18334	**1.04E-05**	0.20	Acetaldehyde (18%), Formaldehyde (17%), Carbon tetrachloride (14%), Naphthalene (13%)	Kraft Pulping: Evaporator LVHC, Kraft Pulping: BL Tanks HVLC, Wastewater (Kraft), Kraft Pulping: Washing, Kraft Pulping: Decker, Bleaching: Kraft	Area sources and point sources Point sources were not correctly coded, so emissions were modeled as fugitives. Additionally, the lime kiln was mapped to causticizing: misc and included in the Subpart S risk assessment. (configuration appears realistic)
41071NEI40648	**9.01E-06**	0.44	Acetaldehyde (70%), Naphthalene (18%)	Paper Stock Prep	Point sources and large area source (10' Release Height) (configuration appears realistic)
37087NEI40282	**8.98E-06**	0.29	Acetaldehyde (44%), Formaldehyde (32%)	Papermaking, Kraft Pulping: O2 Delig HVLC	PMs are point sources (configuration appears realistic)
55141NEIWI7720116	**8.51E-06**	0.41	Acetaldehyde (79%), Formaldehyde (12%)	Wastewater (Kraft)	Mostly area sources Estimated total facility emissions were erroneously input for each clarifier and basin, rather than the contribution of each basin or clarifier to the total, resulting in massive over-reporting of emissions. Census block receptor with MIR is located on company property (configuration appears realistic)
23025NEIME0250002	**7.58E-06**	0.31	Naphthalene (60%), Acetaldehyde (23%)	Mechanical Pulping	General MP Area Source 10' Release Height Point sources were erroneously modeled as

Facility NEI ID	Cancer MIR	Non-cancer Max HI	Risk Driver (% of Risk)	Risk Driver Source Group(s)	Comments on Source Contribution and Characterization
					area sources (oversimplified configuration may lead to overestimated risk)
55141NEI42695	**7.42E-06**	0.29	Beryllium compounds (84%)	Kraft Pulping: Digester LVHC	Most risk contributed by area sources Mistakenly reported results of SARA 313 threshold calculations as emissions. Under SARA 313, facilities must consider whether trace amounts of certain compounds occurring naturally in wood are 'processed' in sufficient quantity to require reporting under this regulation. Beryllium is not emitted from the kraft pulping process.
47071NEI41552	**7.14E-06**	0.36	Acetaldehyde (98%)	Wastewater (Kraft)	Point and WW area sources (WW area is mislocated too close to a receptor)
22073NEI6057	**5.27E-06**	0.22	Acetaldehyde (59%), Naphthalene (21%)	Papermaking, Paper Stock Prep	All sources shifted south several hundred meters
12123NEI47091	**5.22E-06**	0.16	Hexachloroethane (78%)	Kraft Pulping: Washing, Bleaching: Kraft	Point sources WW area source Bleach plant source appears to be mislocated and may lead to overestimated risk HCE emissions were estimated from a trade group emission factor based on limited and questionable data, the majority of which was non-detect.
41041NEI40600	**4.94E-06**	0.15	Acetaldehyde (33%), Formaldehyde (12%), 1,1,2-Trichloroethane (11%), Tetrachloroethene (10%)	Papermaking, Kraft Pulping: BL Tanks HVLC, NSSC Pulping	PP Area Sources have most of contributing emissions (configuration appears realistic)
23029NEI46835	**4.86E-06**	0.20	Acetaldehyde (74%), Naphthalene (16%)	Wastewater (Kraft)	WW area source located incorrectly across the river Modeled risks would be affected
55087NEI43207	**4.32E-06**	0.22	Acetaldehyde (90%)	Papermaking	Risk associated with point sources

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Facility NEI ID	Cancer MIR	Non-cancer Max HI	Risk Driver (% of Risk)	Risk Driver Source Group(s)	Comments on Source Contribution and Characterization
					(configuration appears realistic)
53053NEI13363	**4.30E-06**	0.07	Formaldehyde (71%), Acetaldehyde (18%)	Wastewater (Kraft), Papermaking	Some area sources location slightly incorrect WW area sources drive the risk Mis-reported and over-reported emissions of formaldehyde and acetaldehyde from primary and secondary clarifiers (WW) (configuration otherwise appears realistic)
51019NEI42211	**4.25E-06**	0.20	Acetaldehyde (83%)	Papermaking, Semichem Pulping	PP Area Sources located incorrectly (configuration otherwise appears realistic)
45043NEI41314	**4.25E-06**	0.16	Acetaldehyde (39%), Hexachloroethane (25%)	Kraft Pulping: Decker, Bleaching: Kraft, Causticizing: Slaker, Wastewater (Kraft), Kraft Pulping: LVHC	WW area source located incorrectly Modeled risk would be affected.
42013NEI7104	**4.09E-06**	0.07	1,1,2-Trichloroethane (45%), Carbon Tetrachloride (20%)	Bleaching: Kraft	Point source (Height = 7ft) WW sources incorrectly located Incorrect release height could lead to overestimated risk
42047NEI40686	**3.85E-06**	0.07	Hexachloroethane (50%), Acetaldehyde (22%), Formaldehyde (18%)	Bleaching: Kraft, Causticizing: Misc & Lime Mud	BK: Pt Source C&LM: Pt Source HCE emissions were estimated from a trade group emission factor based on limited and questionable data, the majority of which was non-detect. (configuration appears realistic)
24001NEI33135	**3.77E-06**	0.14	Acetaldehyde (29%), Carbon Tetrachloride (21%), Formaldehyde (14%)	Kraft Pulping: Decker	Area source (Height = 10 ft) Low release could lead to overestimated risk Emissions from multiple sources were reported as both point and fugitive releases, resulting in significant double-counting

Facility NEI ID	Cancer MIR	Non-cancer Max HI	Risk Driver (% of Risk)	Risk Driver Source Group(s)	Comments on Source Contribution and Characterization
47163NEI41599	**3.62E-06**	0.14	Hexachloroethane (50%), Acetaldehyde (42%)	Bleach Plant, Wastewater	BP: Pt Source, WW: Area Source HCE emissions were estimated from a trade group emission factor based on limited and questionable data, the majority of which was non-detect. Wastewater emissions were mapped to an SCC code for miscellaneous, rather than 30701202 (configuration appears realistic)
13103NEI8178	**3.34E-06**	0.06	Acrylonitrile (66%), Acetaldehyde (21%)	Papermaking, Wastewater: General	Point Sources, Area Source (configuration appears realistic)
13127NEI8196	**3.27E-06**	0.14	Acetaldehyde (73%)	Wastewater: Kraft	WW Area Source Located and Sized Incorrectly May affect modeled risk
48241NEI6450	**3.25E-06**	0.09	Acetaldehyde (47%), Formaldehyde (29%)	Papermaking	Area Sources Located Incorrectly, Receptor may be on Property, WW sized incorrectly and could affect modeled risk
13115NEI26495	**3.18E-06**	0.09	Formaldehyde (42%), Acetaldehyde (42%)	Papermaking	NCASI Default Parameters (configuration appears realistic)
53031NEI42357	**3.10E-06**	0.18	Acetaldehyde (97%)	Wastewater: Kraft	Area source and point sources (configuration appears realistic)
05081NEI18660	**3.04E-06**	0.08	Formaldehyde (35%), Acetaldehyde (33%), Hexachloroethane (30%)	Kraft Pulping, Papermaking, Bleaching	Stack point sources erroneously modeled as fugitive sources (Height=10 ft) are major contributors. Likely to overestimate risk
17021NEIIL0215971	**3.00E-06**	0.15	Acetaldehyde (100%)	Papermaking	Single emission point (Height = 50 ft) Oversimplified and likely to overestimate risk
41039NEI45182	**2.80E-06**	0.05	Formaldehyde (75%), Acetaldehyde (16%)	Kraft Pulping: Digester LVHC	Point and area sources are mis-located (configuration otherwise appears realistic)
37083NEI47104	**2.73E-06**	0.12	Acetaldehyde (86%)	Papermaking	Most risk from paper machine erroneously modeled as fugitive area sources (Height=10') Low release could lead to overestimated risk

Facility NEI ID	Cancer MIR	Non-cancer Max HI	Risk Driver (% of Risk)	Risk Driver Source Group(s)	Comments on Source Contribution and Characterization
27145NEI12407	**2.72E-06**	0.09	Cadmium (26%), Formaldehyde (20%), Nickel (13%), Acetaldehyde (13%), Arsenic (13%)	Kraft Pulping: Incinerator, Mechanical Pulping, Papermaking	Three point sources (40 ft to 80 ft) (configuration appears realistic)
37047NEI40247	**2.69E-06**	0.09	Acetaldehyde (40%), Formaldehyde (38%), Hexachloroethane (19%)	Kraft Pulping: Washing, Bleaching: Kraft, Kraft Pulping: Digester LVHC	Multiple point sources (configuration appears realistic)
51580NEI759	**2.62E-06**	0.08	Acetaldehyde (40%), Carbon Tetrachloride (19%), Formaldehyde (19%), 1,1,2-Trichloroethane (14%)	Kraft Pulping (Digester LVHC, Knotter), Wastewater	Fugitive sources (Height=10 ft) Low release heath could lead to overestimated risk
01001NEI8560	**2.58E-06**	0.10	Acetaldehyde (68%), Formaldehyde (26%)	Wastewater, Papermaking	Receptor located in unpopulated area. Risk in populated area is 2.3E-06
55009NEI42482	**2.46E-06**	0.03	Formaldehyde (87%)	Bleaching	Point sources Emissions of 13 ton/yr was result of miscoding (should be 0.00013 ton/yr)
51009NEIVA00022	**2.32E-06**	0.10	Acetaldehyde (79%), Benzene (21%)	Papermaking, Semichem Pulping	Modeled as four point sources (two co-located) and six overlapping area sources Incorrect sources characterization likely to overestimate risk
27061NEI34030	**2.30E-06**	0.04	Naphthalene (57%), Formaldehyde (20%)	Papermaking	Modeled as a single point source Oversimplification likely overestimates risk
12005NEI8278	**2.28E-06**	0.07	Hexachloroethane (27%), Acetaldehyde (20%), Formaldehyde (14%), Tetrachloroethane (10%)	Bleaching, Kraft Pulping: Washing, Papermaking, Causticizing:	Point sources and WW area source (configuration appears realistic) HCE emissions were estimated from a trade group emission factor based on limited and questionable data, the majority of which was non-detect.

Facility NEI ID	Cancer	Non-cancer	Risk Driver	Risk Driver	Comments on Source Contribution and Characterization
	MIR	Max HI	(% of Risk)	Source Group(s)	
39061NEI11610	**2.27E-06**	0.05	Naphthalene (43%), Acetaldehyde (29%), Formaldehyde (28%)	Papermaking	Modeled as one point source and two large overlapping area sources composed of various emission sources. Oversimplification likely overestimates risk
23007NEI6261	**2.22E-06**	0.12	Acetaldehyde (67%), Naphthalene (27%)	Wastewater, Mechanical pulping, Papermaking	Point sources with dominant WWTP area source Estimated emissions of acetaldehyde and naphthalene from WW sources are over-stated (configuration appears realistic)
45031NEI43472	**2.19E-06**	0.11	Acetaldehyde (100%)	Papermaking	Paper machines represented by single stack Oversimplification likely overestimates risk
26041NEI33883	**2.04E-06**	0.12	Acetaldehyde (49%), Formaldehyde (27%), Naphthalene (14%)	Wastewater treatment	Fugitive area source is incorrectly located and may affect risk estimate
13051NEI8186	**2.00E-06**	0.03	Formaldehyde (72%), Acetaldehyde (13%)	Kraft Pulping: LVHC, Wastewater	Fugitive and point sources (configuration appears realistic)

4.0 Discussion of HEM3 Modeling Data

A number of modeling issues were identified in the subset of EPA's October 2011 residual risk modeling that was reviewed by AECOM. Issues identified included incorrectly characterized or misplaced sources at facilities identified with elevated risk. Experience in dispersion modeling indicates that the application of more refined source characterization, correction of misplaced sources, and removing unrepresentative receptors are expected to result in substantial reductions of modeled risks. Therefore, making these types of corrections to the HEM3 modeling performed in EPA's 2011draft risk assessment are expected to result in lower modeled risk levels and thereby strengthen the basis of EPA's determination that the residual risk levels are acceptable for this industrial sector.

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5.0 Comments on EPA's Selection of HAPs in the RTR Risk Assessment

The value of a risk assessment can be greatly diminished if it includes parameters that are largely unknown or highly uncertain and also have the potential to drive the risk estimates. An example of such a parameter is acrolein, and as such we support EPA's decision to exclude this HAP from the RTR risk assessment. EPA states that it removed acrolein emissions from the risk assessment due to a high degree of uncertainty in the emissions data. The uncertainty regarding acrolein actually involves two parameters that proportionately affect modeled risk: emission rate and dose-response value. The emissions uncertainty stems from the level of difficulty in measuring this highly reactive chemical at the very low levels at which it may be present in Subpart S air releases. Emission rates based partly or entirely on detection limits would greatly exaggerate what may be virtually non-existent emissions. There is also uncertainty in the appropriate Reference Concentration (RfC) to apply as the current value is inappropriately low and should be replaced by an RfC based on more recent studies by the Hamner Institute using pharmacokinetic models. For acrolein the combined effect of greatly overestimated emissions and its currently very low Reference Concentration (RfC) could result in modeled risks that do not reflect reality as they overshadow and mask the real risk, i.e., the risk of HAPs for which emission rates have been firmly established. As such, including acrolein in the RTR risk assessment would render the assessment useless for risk based decision-making. EPA's decision to exclude acrolein in this assessment represents sound science and is supported by risk assessment principles.

Another sound risk assessment decision made by EPA in the RTR was to not include dioxin/furan as a chemical of potential concern in the multi-pathway risk assessment because Dioxin/furan emissions are not expected from Subpart S sources. It well known that risk assessments for some types of combustion sources, such a waste incineration, dioxin/furan has commonly been determined to contribute substantially to modeled cancer risk because it bioaccumulates in the environment and through the food chain. In contrast to acrolein, methods have been developed that can detect dioxin/furan at low levels. Because the there are no established formation mechanisms related to Subpart S sources and no reliable emissions testing that indicates that dioxin/furan are emitted at detectable levels from these sources, EPA's basis for not including dioxin/furan in the multi-pathway risk assessment is firmly established.

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Appendix A

RTR Figures

Figures for all Pulp and Paper facilities with Cancer Risk greater 2 in a million.

Key:

- Point Source

- Area Source

- Census Block Receptor Location

- Maximum Impact Receptor Location

Figure 1. Facility 21091NEI32869A

Figure 2. Facility 01023NEI18334

Figure 3. Facility 41071NEI40648

Figure 4. Facility 37087NEI40282

Figure 5. Facility 55141NEIWI7720116

Figure 6. 23025NEIME0250002

Figure 7. 55141NEI42695

Figure 8. 47071NEI41552

Figure 9. Facility 22073NEI6057

Figure 10. Facility 12123NEI47091

Figure 11. Facility 41041NEI40600

Figure 12. Facility 23029NEI46835

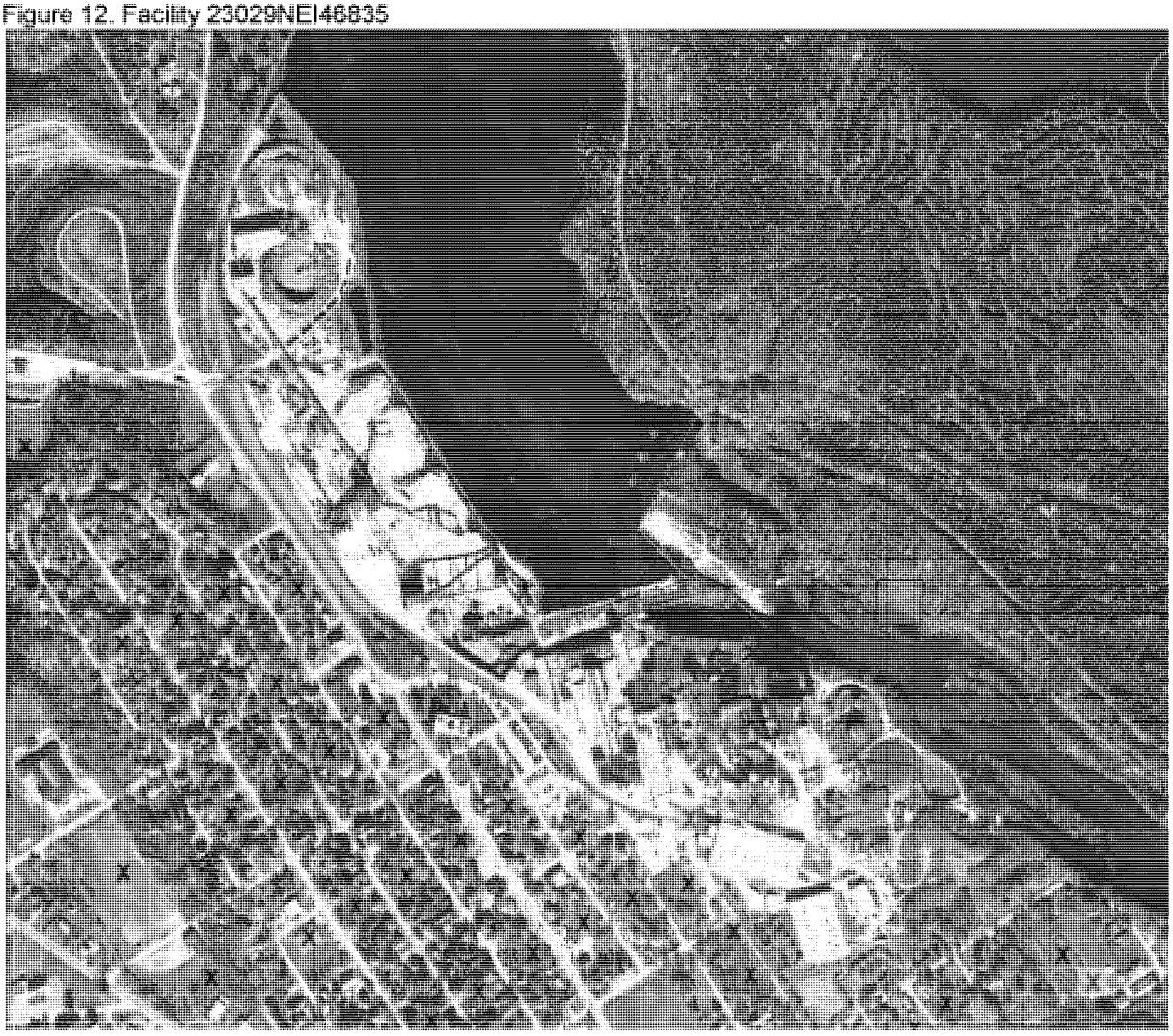

Figure 13. Facility 55087NEI43207

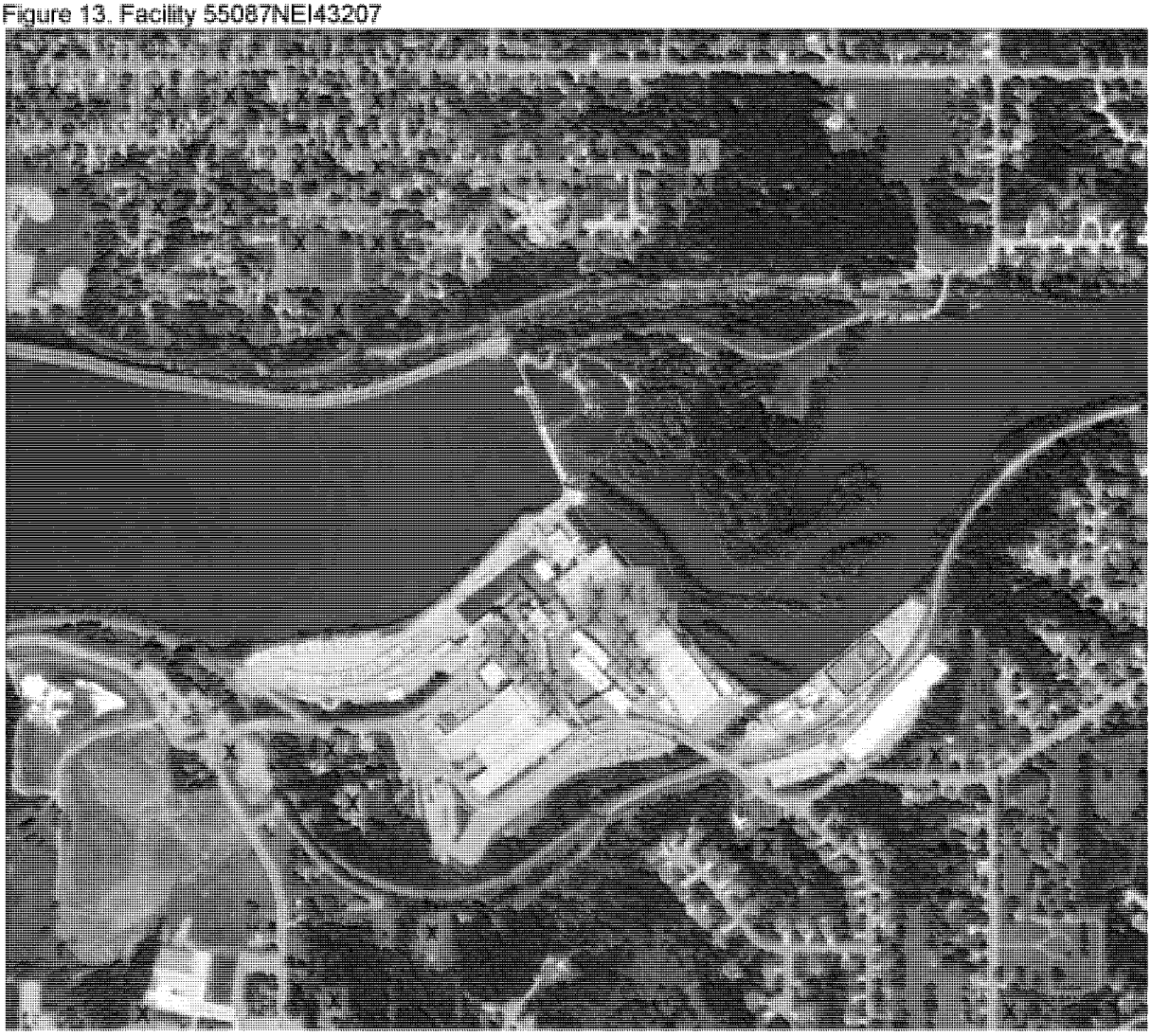

Figure 14. Facility 53053NEI13363

Figure 15. Facility 51019NEI42211

Figure 16. Facility 45043NEI41314

Figure 17. Facility 42013NEI7104

Figure 18. Facility 42047NEI40686

Figure 19. Facility 24001NEI33135

Figure 20. Facility 47163NEI41599

Figure 21. Facility 13103NEI8178

Figure 22. Facility 13127NEI8196

Figure 23. Facility 48241NEI6450

Figure 24. Facility 13115NEI26495

Figure 25. Facility 53031NEI42357

Figure 26. Facility 05081NEI18660

Figure 27. Facility 17021NEIIL0215971

Figure 28. Facility 41039NEI45182

Figure 29. Facility 37083NEI47104

Figure 30. Facility 27145NEI12407

Figure 31. Facility 37047NEI40247

Figure 32. Facility 51580NEI759

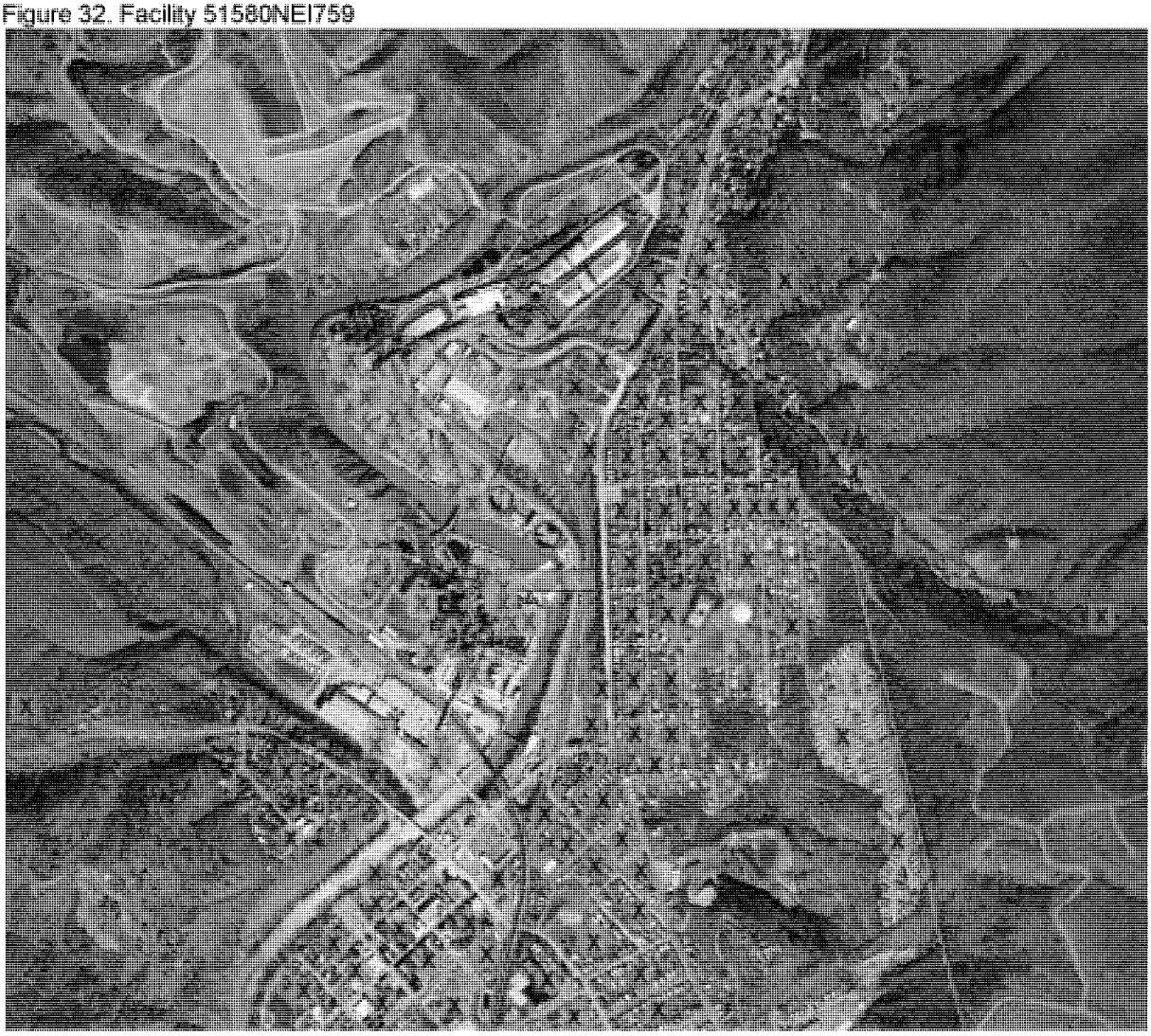

Figure 33. Facility 01001NEI8560

Figure 34. Facility 55009NEI42482

Figure 35. Facility 51009NEIVA00022

Figure 36. Facility 27061NEI34030

Figure 37. Facility 12005NEI8278

Figure 38. Facility 39061NEI11610

Figure 39. Facility 23007NEI6261

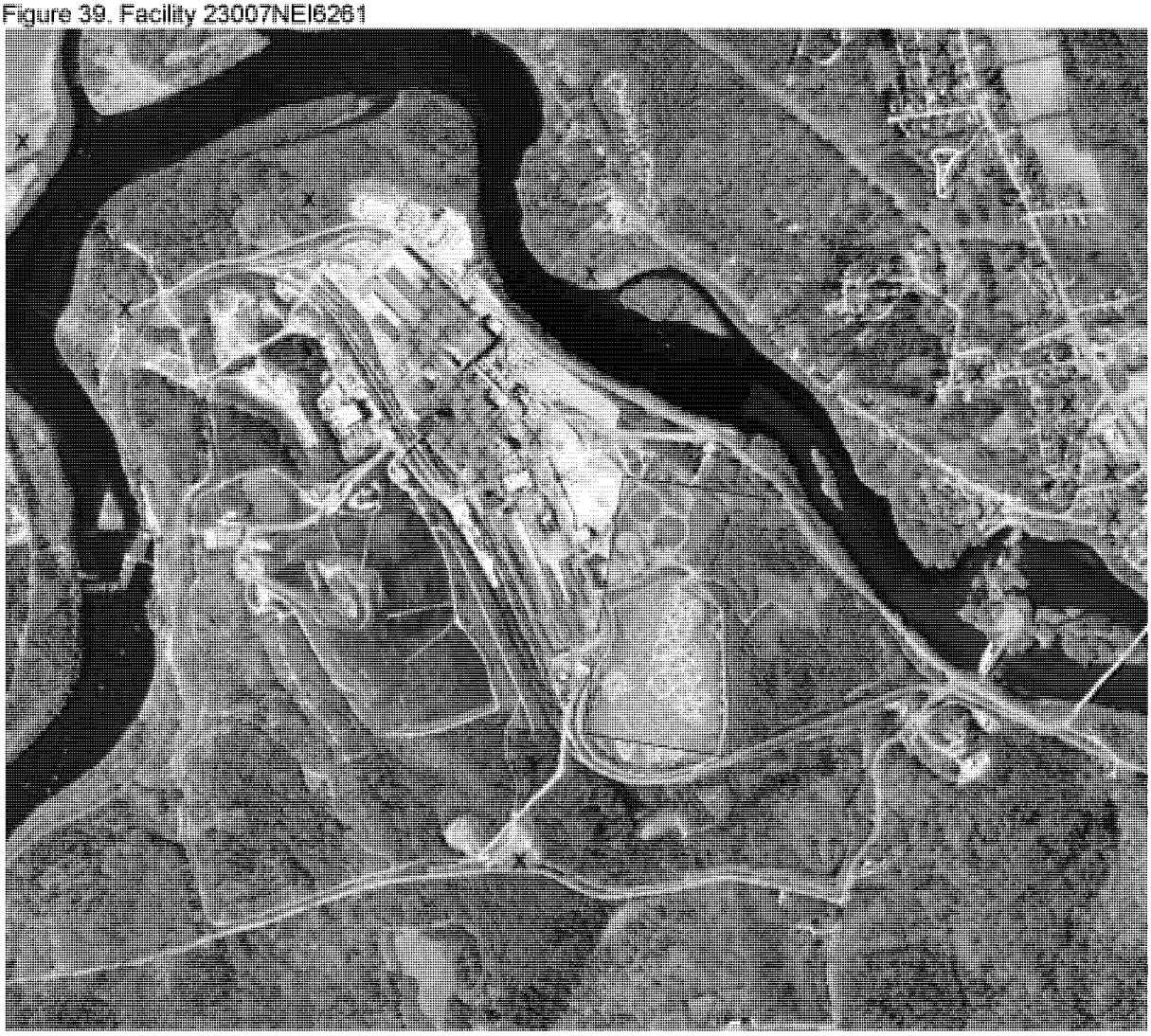

Figure 40. Facility 45031NEI43472

Figure 41. Facility 26041NEI33883

Figure 42. Facility 13051NEI8186

Appendix B

RTR Tables

List of Facilities Submitting Data Corrections to the2011 Residual Risk Modeling as of 1 pm 2/27/2012

	Facility NEI ID	Subpart S Source Category Chronic Risk	Facility-Wide Chronic Risk	SC% of Facility-wide Cancer Risk	Submitted Revision?
1	21091NEI32869A	**1.21E-05**	**1.23E-05**	98%	Y
2	01023NEI18334	**1.04E-05**	**1.64E-05**	64%	Y
3	41071NEI40648	**9.01E-06**	**9.07E-06**	99%	--
4	37087NEI40282	**8.98E-06**	**3.36E-05**	27%	Y
5	55141NEIWI7720116	**8.51E-06**	**8.65E-06**	98%	Y
6	23025NEIME0250002	**7.58E-06**	**8.78E-06**	86%	Y
7	55141NEI42695	**7.42E-06**	**7.44E-06**	100%	Y
8	47071NEI41552	**7.14E-06**	**7.94E-06**	90%	pending
9	22073NEI6057	**5.27E-06**	**8.40E-06**	63%	--
10	12123NEI47091	**5.22E-06**	**2.88E-05**	18%	Y
11	41041NEI40600	**4.94E-06**	**6.74E-06**	73%	Y
12	23029NEI46835	**4.86E-06**	**5.35E-06**	91%	--
13	55087NEI43207	**4.32E-06**	**1.02E-05**	42%	
14	53053NEI13363	**4.30E-06**	**4.85E-06**	89%	Y
15	45043NEI41314	**4.25E-06**	**5.62E-06**	76%	Y
16	51019NEI42211	**4.25E-06**	**4.27E-06**	100%	Y
17	42013NEI7104	**4.09E-06**	**7.91E-06**	52%	pending
18	42047NEI40686	**3.85E-06**	**4.43E-06**	87%	Y
19	24001NEI33135	**3.77E-06**	**8.69E-06**	43%	Y
20	47163NEI41599	**3.62E-06**	**5.13E-06**	71%	Y
21	13103NEI8178	**3.34E-06**	**3.91E-06**	86%	Y
22	13127NEI8196	**3.27E-06**	**3.57E-06**	91%	Y
23	48241NEI6450	**3.25E-06**	**4.03E-06**	81%	Y
24	13115NEI26495	**3.18E-06**	**5.02E-06**	63%	Y
25	53031NEI42357	**3.10E-06**	**3.18E-06**	98%	
26	05081NEI18660	**3.04E-06**	**3.42E-06**	89%	
27	17021NEIIL0215971	**3.00E-06**	**3.18E-06**	94%	--
28	41039NEI45182	**2.80E-06**	**3.59E-06**	78%	Y
29	37083NEI47104	**2.73E-06**	**7.08E-06**	39%	Y
30	27145NEI12407	**2.72E-06**	**2.75E-06**	99%	Y
31	37047NEI40247	**2.69E-06**	**4.56E-06**	59%	Y
32	51580NEI759	**2.62E-06**	**5.80E-06**	45%	Y
33	01001NEI8560	**2.58E-06**	**3.67E-06**	70%	Y
34	55009NEI42482	**2.46E-06**	**2.70E-06**	91%	Y
35	51009NEIVA00022	**2.32E-06**	**2.58E-06**	90%	--
36	27061NEI34030	**2.30E-06**	**2.39E-06**	96%	Y
37	12005NEI8278	**2.28E-06**	**3.54E-06**	64%	
38	39061NEI11610	**2.27E-06**	**6.84E-06**	33%	
39	23007NEI6261	**2.22E-06**	**2.72E-06**	81%	Y
40	45031NEI43472	**2.19E-06**	**2.36E-06**	93%	
41	26041NEI33883	**2.04E-06**	**2.31E-06**	88%	Y
42	13051NEI8186	**2.00E-06**	**2.41E-06**	83%	Y
43	13051NEI26476	**1.91E-06**	**1.95E-06**	98%	
44	47107NEI41565	**1.89E-06**	**3.44E-06**	55%	

	Facility NEI ID	Subpart S Source Category Chronic Risk	Facility-Wide Chronic Risk	SC% of Facility-wide Cancer Risk	Submitted Revision?
45	42131NEI40738	**1.86E-06**	**2.15E-06**	86%	--
46	40089NEI11251	**1.84E-06**	**2.32E-06**	79%	Y
47	28077NEI11172	**1.71E-06**	**5.74E-06**	30%	Y
48	05003NEI54342	**1.68E-06**	**2.58E-06**	65%	Y
49	16069NEI26581	**1.49E-06**	**5.65E-06**	26%	Y
50	28111NEI34066	**1.44E-06**	**1.90E-06**	76%	Y
51	21107NEI11367	**1.42E-06**	**6.94E-06**	20%	
52	05069NEI18658	**1.39E-06**	**1.88E-06**	74%	pending
53	42133NEI7181	**1.35E-06**	**2.07E-06**	65%	Y
54	28149NEI34070	**1.32E-06**	**2.05E-06**	64%	Y
55	41043NEI13340	**1.29E-06**	**1.59E-06**	81%	
56	13305NEI26526	**1.28E-06**	**2.51E-06**	51%	
57	55073NEI54400	**1.18E-06**	**1.39E-06**	85%	Y
58	12107NEI8265	**1.16E-06**	**1.45E-06**	80%	Y
59	53015NEI42341B	**1.15E-06**	**1.15E-06**	100%	
60	22117NEI46814	**1.10E-06**	**3.40E-06**	32%	
61	22049NEI33023	**1.10E-06**	**1.59E-06**	69%	
62	22069NEI33025	**1.10E-06**	**1.30E-06**	84%	Y
63	23017NEI6273	**1.09E-06**	**1.37E-06**	80%	Y
64	53011NEI46599	**1.05E-06**	**2.73E-06**	38%	Y
65	01131NEI8619	**1.04E-06**	**1.79E-06**	58%	Y
66	51101NEI42254	**1.02E-06**	**2.45E-06**	42%	
67	45069NEI47074	**1.02E-06**	**1.40E-06**	73%	Y
68	13099NEI26491	9.95E-07	**2.21E-06**	45%	
69	12089NEI8261	9.31E-07	**1.24E-06**	75%	
70	12033NEI26309	9.23E-07	**2.76E-06**	33%	Y
71	45019NEI41252	8.85E-07	**1.29E-06**	69%	
72	37049NEI45206	8.85E-07	9.54E-07	93%	Y
73	22011NEI7559	8.80E-07	**1.51E-05**	6%	
74	22031NEI33013	8.44E-07	**1.30E-06**	65%	Y
75	39031NEI11461	8.18E-07	**3.13E-06**	26%	
76	26101NEI33945	8.16E-07	8.98E-07	91%	
77	41007NEI40554	8.00E-07	**1.78E-06**	45%	Y
78	13185NEI26504	7.94E-07	**5.49E-06**	14%	Y
79	01047NEI18335	7.69E-07	**1.08E-06**	71%	Y
80	21007NEI11338	7.44E-07	**1.80E-05**	4%	Y
81	05029NEI46852	7.35E-07	7.96E-07	92%	
82	01121NEI18390	6.85E-07	**6.34E-06**	11%	
83	54037NEI23	6.53E-07	7.11E-07	92%	--
84	53015NEI42341A	6.47E-07	7.19E-07	90%	
85	22033NEI46817	6.43E-07	**1.98E-06**	32%	Y
86	45091NEI47077	6.42E-07	**1.55E-06**	41%	
87	13021NEI26471	6.28E-07	**1.56E-06**	40%	--
88	23019NEI33103	5.54E-07	**1.23E-06**	45%	--
89	55073NEI42689	5.50E-07	6.66E-07	83%	
90	47085NEI46866	5.40E-07	**1.23E-06**	44%	

	Facility NEI ID	Subpart S Source Category Chronic Risk	Facility-Wide Chronic Risk	SC% of Facility-wide Cancer Risk	Submitted Revision?
91	55009NEI42486	5.12E-07	9.07E-07	56%	
92	25017NEI6175	5.08E-07	5.08E-07	100%	
93	53009NEI42329	5.05E-07	**1.04E-06**	48%	
94	12089NEI26382	5.05E-07	8.00E-07	63%	
95	53015NEI42338	5.02E-07	7.80E-07	64%	
96	01113NEI46931	4.77E-07	**1.47E-06**	32%	
97	37117NEI9201	4.73E-07	9.90E-07	48%	
98	54057NEI706	4.65E-07	5.36E-07	87%	
99	48067NEI41628	4.52E-07	**1.02E-06**	44%	Y
100	27071NEI12411	4.44E-07	9.42E-07	47%	
101	01053NEI18338	4.31E-07	**1.24E-06**	35%	Y
102	01079NEI18357	4.29E-07	**1.26E-06**	34%	Y
103	13245NEI26514	4.17E-07	8.98E-07	46%	Y
104	55141NEI46739	4.00E-07	**1.11E-06**	36%	Y
105	28087NEI34064	3.90E-07	4.89E-07	80%	
106	48361NEI12492	3.83E-07	**1.95E-06**	20%	
107	23025NEI33118	3.83E-07	5.14E-07	74%	--
108	05069NEI18657	3.70E-07	8.80E-07	42%	
109	25003NEIMA10626	3.62E-07	**1.26E-06**	29%	--
110	01071NEI18347	3.57E-07	9.64E-07	37%	
111	51085NEI208	3.54E-07	6.04E-07	59%	--
112	45079NEI46760	3.49E-07	8.71E-07	40%	Y
113	55085NEI43202	3.35E-07	**1.02E-06**	33%	
114	01025NEI8601	2.93E-07	8.23E-07	36%	
115	01099NEI18373	2.92E-07	3.54E-07	82%	Y
116	51670NEI42317	2.83E-07	4.51E-07	63%	
117	13095NEI26487	2.79E-07	2.90E-07	96%	--
118	55087NEI42710	2.73E-07	3.23E-07	85%	
119	13245NEI8122	2.62E-07	5.38E-07	49%	
120	55099NEI42730	2.40E-07	**1.44E-06**	17%	
121	55009NEIWI4050324	2.18E-07	2.22E-07	98%	Y
122	26147NEI33981	2.13E-07	**3.16E-05**	1%	Y
123	53071NEI42410	1.93E-07	5.56E-07	35%	
124	27137NEIMN14904	1.89E-07	1.89E-07	100%	
125	36113NEI39968	1.86E-07	8.38E-07	22%	
126	04017NEI13216	1.76E-07	4.14E-07	43%	--
127	27017NEI12368	1.73E-07	7.29E-07	24%	--
128	13193NEI26506	1.59E-07	**2.22E-06**	7%	
129	28043NEI11108	1.57E-07	4.84E-07	32%	
130	55141NEI42963	1.56E-07	1.57E-07	99%	
131	55009NEI42495	1.51E-07	4.97E-07	30%	
132	40101NEI12980	1.49E-07	6.35E-07	23%	Y
133	23019NEI33104	1.48E-07	3.16E-07	47%	
134	55115NEI42800	1.47E-07	**1.91E-06**	8%	--
135	55073NEI42690	1.45E-07	6.81E-07	21%	
136	05041NEI18652	1.29E-07	3.59E-07	36%	Y

	Facility NEI ID	Subpart S Source Category Chronic Risk	Facility-Wide Chronic Risk	SC% of Facility-wide Cancer Risk	Submitted Revision?
137	36031NEI35908	1.17E-07	5.54E-07	21%	Y
138	55097NEIWI7500086	1.13E-07	1.16E-07	97%	
139	55079NEIWI0793640	1.12E-07	1.22E-07	92%	--
140	45041NEI7933	1.08E-07	2.17E-07	50%	
141	13179NEI8177	1.07E-07	3.97E-07	27%	--
142	23009NEI6284	1.05E-07	1.97E-07	53%	
143	55069NEI46750	9.83E-08	5.27E-07	19%	
144	27035NEI34020	9.79E-08	2.87E-07	34%	
145	39017NEI11602	7.40E-08	1.19E-07	62%	--
146	18165NEI2INT16350	6.75E-08	6.75E-08	100%	
147	47105NEITN1050093	6.34E-08	7.54E-08	84%	--
148	39113NEI11645	6.13E-08	1.75E-07	35%	
149	39017NEI11600	5.51E-08	**6.55E-06**	1%	--
150	36045NEI36019	5.18E-08	1.82E-07	28%	--
151	09011NEICT3102	5.01E-08	6.09E-08	82%	--
152	55139NEIWI4710355	4.43E-08	5.56E-08	80%	--
153	55141NEI42961	4.32E-08	6.39E-08	68%	
154	40031NEW73505	4.22E-08	4.22E-08	100%	
155	39141NEI40488	3.76E-08	**5.25E-06**	1%	
156	13175NEIGAT$3911	3.39E-08	**6.97E-06**	0%	--
157	26043NEI33887	2.88E-08	4.35E-07	66%	
158	01091NEI45474	2.77E-08	6.04E-07	46%	
159	26003NEI33866	2.45E-08	1.08E-07	23%	
160	42013NEI7106	1.40E-08	1.40E-08	100%	--
161	26109NEI33950	8.45E-09	8.45E-09	100%	
162	42101NEI40720	7.58E-09	1.76E-07	4%	--
163	42101NEIPA1013489	7.36E-09	1.30E-07	57%	--
164	12031NEI26304	4.13E-09	4.13E-09	100%	
165	36115NEINY5532600	1.44E-09	9.08E-07	0%	
166	41009NEI40553	4.20E-10	6.70E-10	63%	
167	36115NEINY5533400	3.12E-10	1.02E-07	0%	
168	53061NEI42385	0.00E+00	4.78E-07	0%	--
169	13235NEIGAT$3909	0.00E+00	0.00E+00		
170	53051NEI2WAT18798	0.00E+00	0.00E+00		
171	55097NEIWIT$8597	0.00E+00	0.00E+00		
No. of Facilities Submitting Revisions to Date (includes 'pending'):					66

February 27, 2012

Submitted via email (a-and-r-docket@epa.gov)
EPA Docket Center
EPA West (Air Docket)
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

Re: National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry, Proposed Rule, 76 Fed. Reg. 81328 (Dec. 27, 2011), Docket ID No. EPA-HQ-OAR-2007-0544

Dear Sir or Madam:

The Formaldehyde Panel of the American Chemistry Council (ACC) appreciates this opportunity to comment on the U.S. Environmental Protection Agency's proposed rule for the National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry (Proposed Rule). ACC strives to ensure appropriate product stewardship of chemicals, and as part of its mission, addresses important science and public policy issues related to formaldehyde chemistry, including proposed rulemaking and characterization of formaldehyde risk.

As set forth in these comments, EPA has failed to comport with the explicit Information Quality Act (IQA) Guidelines. The information that serves as a basis for the Proposed Rule is "influential" scientific risk assessment information and therefore must adhere to a rigorous standard of quality. Despite the requirements of the IQA Guidelines, EPA has failed to support key conclusions in the Proposed Rule with the best available science. By applying the outdated Integrated Risk Information System (IRIS) dose-response values in determining formaldehyde inhalation exposure risk, EPA is not basing the Proposed Rule on the best available science.

The critical importance of using best available science as a basis for regulatory decisions is well established. On January 18, 2011, President Obama issued Executive Order 13563, in which the President ordered executive agencies to improve regulation and regulatory review. The President stresses the importance of protecting public health and the environment "while promoting economic growth, innovation, competitiveness, and job creation." 76 Fed. Reg. 3821, 3821 (Jan. 21, 2011). The regulatory system must "be based on the best available science," "identify and use the best, most innovative, and least burdensome tools for achieving regulatory ends," and "take into account benefits and costs, both quantitative and qualitative." *Id.* Importantly, an agency can propose or adopt a regulation "only upon a reasoned determination that its benefits justify its costs." *Id.* Moreover, "each agency shall ensure the objectivity of any scientific and technological information and processes used to

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support the agency's regulatory actions." *Id.* at 3822. In finalizing this rulemaking, EPA must comply with the provisions of the Executive Order.

ACC urges EPA to revise the Proposed Rule to accurately convey the best available science and a weight-of-evidence approach in compliance with the IQA Guidelines and Executive Order 13563. In particular, EPA should reject the 1991 IRIS dose-response value and incorporate the Chemical Industry Institute of Toxicology (CIIT, 1999) cancer dose-response value for formaldehyde.

A. The Proposed Rule is subject to EPA and OMB Information Quality Act Guidelines.

Congress enacted the Information Quality Act, Pub. L. No. 106-554, 114 Stat. 2763A-153 to 2763A-154, to "ensur[e,] and maximiz[e,] the quality, objectivity, utility and integrity of information ... disseminated by Federal agencies" such as the EPA. The IQA required the Office of Management and Budget (OMB) to issue government-wide guidance, which each federal agency was to follow through issuance of its own guidelines. In February 2002, OMB issued its guidelines, and EPA issued its agency-specific guidelines (EPA IQA Guidelines) later that year.[1] The purpose of the EPA IQA Guidelines is to apply the OMB Guidelines to the Agency's particular circumstances, and to "establish administrative mechanisms allowing affected persons to seek and obtain correction of information ... disseminated by the agency that does not comply with the [OMB] guidelines...." The information that serves as the basis for EPA's Proposed Rule must meet OMB's guidelines as well as the Agency's own guidelines.

The information that serves as a basis for the Proposed Rule is influential information and must adhere to a rigorous standard of quality. The Proposed Rule is based on "influential" scientific risk assessment information as set forth in EPA IQA Guidelines[2] because it contains "information disseminated in support of top Agency actions (*i.e.*, rules...)" and is "[m]ajor work product[]" that "will have ... a clear and substantial impact (*i.e.*, potential change or effect) on important public policies or private sector decisions."[3] The information underlying the Proposed Rule, therefore, must adhere to a rigorous standard of quality.[4] The substance of the information must be "accurate, reliable, and

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1 OMB, *Guidelines for Ensuring and Maximizing the Quality, Objectivity, Utility, and Integrity of Information Disseminated by Federal Agencies*, 67 Fed. Reg. 8452 (Feb. 22, 2002) (OMB IQA Guidelines); *see* EPA, *Guidelines for Ensuring and Maximizing the Quality, Objectivity, Utility, and Integrity of Information Disseminated by the Environmental Protection Agency*, available at http://www.epa.gov/quality/informationguidelines/documents/EPA_InfoQualityGuidelines.pdf.

2 Pub. L. No. 106-554. The Information Quality Act was developed as a supplement to the Paperwork Reduction Act, 44 U.S.C. §3501 *et seq.*, which requires OMB, among other things, to "develop and oversee the implementation of policies, principles, standards, and guidelines to ... apply to Federal agency dissemination of public information."

3 EPA IQA Guidelines at 19-20 (internal citations omitted); OMB IQA Guidelines at 8455.

4 Quality includes objectivity, utility, and integrity.

unbiased."[5] EPA must use the best available science and supporting studies, as well as "a weight-of-evidence approach that considers all relevant information and its quality."[6]

Despite the numerous safeguards designed by OMB and EPA to ensure data quality, EPA has failed to rely on the best available science in developing the Proposed Rule. EPA failed to comport with the IQA Guidelines in crafting this proposed rule. In particular, EPA incorporates the 1991 IRIS dose-response model – an overly conservative and outdated model – for determining the level of risk presented by formaldehyde exposure and ignored, without any rationale, nearly 25 years of research. The utilization of the IRIS model is all the more egregious considering the availability of the CIIT biologically-based dose-response (BBDR) model, which better reflects the available science.

B. Contrary to IQA Guidelines, EPA inappropriately applies the outdated IRIS dose-response values in determining formaldehyde inhalation exposure risk in support of the Proposed Rule.

In 2004, EPA determined that "the [formaldehyde] dose-response value in IRIS is based on a 1987 study, and no longer represents the best available science in the peer reviewed literature." 69 Fed. Reg. 18327, 18333 (Apr. 7, 2004). EPA went on to state that "the CIIT modeling effort represents the best available application of the available mechanistic and dosimetric science on the dose-response for portal of entry cancers due to formaldehyde exposure." *Id.* This determination led to the incorporation of the CIIT dose-response value for formaldehyde exposure in risk assessments supporting regulatory action. In the Proposed Rule, EPA states:

> Based on subsequent published research, however, the EPA changed its determination regarding the CIIT model, and, in 2010, the EPA returned to using the 1991 IRIS value. The NAS completed its review of the EPA's draft assessment in April of 2011 (http://www.nap.edu/catalog.php?recordid=13142), and the EPA has been working on revising the formaldehyde assessment. The EPA will follow the NAS Report recommendations and will present results obtained by implementing the BBDR model for formaldehyde. The EPA will compare these estimates with those currently presented in the External Review draft of the assessment and will discuss their strengths and weaknesses. As recommended by the NAS committee, appropriate sensitivity and uncertainty analyses will be an integral component of implementing the BBDR model. The draft IRIS assessment will be revised in response to the NAS peer review and public comments and the final assessment will be posted on the IRIS database. In the interim, we will present findings using the 1991 IRIS value as a primary estimate and may also consider other information as the science evolves.

76 Fed. Reg. at 81335.

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5 EPA IQA Guidelines at 22; OMB IQA Guidelines at 8453.

6 EPA IQA Guidelines at 21.

An expert panel of the National Academy of Sciences (NAS) issued the report of its review of formaldehyde risk in April 2011.[7] The NAS panel was highly critical of EPA's 2010 Draft IRIS Toxicological Review of Formaldehyde Inhalation Assessment (Draft IRIS Assessment), and specifically supported the use of the CIIT BBDR model. *See* NAS Report at 34-44. In fact, the panel concluded that "the BBDR model for formaldehyde is one of the best-developed BBDR models to date" and specifically recommended that "EPA use the BBDR model for formaldehyde in its cancer assessment, compare the results with those described in the draft assessment, and discuss the strengths and weaknesses of each approach." NAS Report at 5.

In 2010, EPA rejected the BBDR model because it asserted that the variability of the model is "not supportive of interpreting the CIIT model results as providing a conservative (health-protective) estimate of human risk." 75 Fed. Reg. 80220, 80228 (Dec. 21, 2010) (citing Crump *et al.*, 2008). However, the sensitivity of the model had been questioned based on inappropriate manipulation. As explained by Conolly *et al.* (2009), while it is important to ensure that the BBDR model is "health protective" in its estimation of cancer risk by performing a sensitivity analysis, such an analysis is only valuable if it is constrained by respect for the biological realism of the model-predicted behavior. The NAS panel agreed, stating:

> EPA explored the uncertainties associated with the model and sensitivities of various model components to changes in key parameters and assumptions and, on the basis of those extrapolations, decided not to use the BBDR model in its assessment. Although the committee agrees that EPA's evaluation of the model yielded some important findings on model sensitivity, some of the manipulations are extreme, may not be scientifically justified, and should not have been used as the basis of rejection of the use of the BBDR model in its assessment. Model manipulations that yield results that are implausible or inconsistent with available data should be rejected as a basis for judging the utility of the model.

NAS Report at 5. *See also id.* at 42 ("Although the committee finds that testing of alternative models and the variability in model parameters is consistent with EPA's cancer guidelines, some of the more extreme model scenarios should not have been used as a basis for rejecting the BBDR approach.... Thus, the committee recommends that manipulations of model parameters that yield results that are biologically implausible or inconsistent with the available data be discarded and not used as a basis for rejecting the overall model.")

The 1991 IRIS value does not constitute the best available science and therefore should not be used in determining formaldehyde inhalation exposure risk in support of the Proposed Rule. The BBDR model, which incorporates over 20 years of research to help characterize the roles of regenerative cellular proliferation (RCP) and DNA-protein cross-link (DPX) formation in formaldehyde carcinogenicity

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[7] National Research Council of the National Academies, *Review of the Environmental Protection Agency's Draft IRIS Assessment of Formaldehyde* (2011) (NAS Report).

(CIIT, 1999; NAS Report at 35), is a superior model for determining the cancer risk associated with formaldehyde exposure. The NAS panel concluded:

> the existing BBDR models were developed from an impressive exposure- and time-dependent database on the modes of actions of formaldehyde in rats and monkeys; exquisitely detailed dosimetry models in rats, monkeys, and humans; and sparse data on humans that required scale-up of key model parameter values from animal studies and other biologic data and epidemiologic observations to constrain the human model predictions. The scope of the research makes this one of the best-developed BBDR models to date for any chemical, even with its acknowledged uncertainties.

NAS Report at 42.

Furthermore, starting with biological data and a bottom-up linear extrapolation model using EPA's assumptions, Swenberg *et al.* (2010) report:

> Our estimates of HL [Hodgkin lymphoma] and LEU [leukemia] risk diverge even more dramatically from the corresponding U.S. EPA estimates.... The marked disparities between the adduct-based and epidemiology-based cancer risk estimates for distant sites suggest strongly that the excess risks of HL and NPC [nasopharyngeal cancer] that have been reported in association with occupational formaldehyde exposures cannot be due to formaldehyde.... Comparison of our risk estimates with corresponding estimates from the U.S. EPA draft document shows the latter to be markedly higher. This discrepancy between results obtained with molecular dosimetry and those that rely on highly uncertain retrospective exposure reconstructions calls into serious question the credibility of attributing increased human mortality from these cancers, particularly at distant sites, to occupational formaldehyde exposures.

Swenberg *et al.* (2010), at S136-S137.

C. <u>The NAS Report should be used in determining what constitutes the best available science.</u>

1. <u>The deference given to the 1991 IRIS Assessment is directly at odds with EPA's mandate to "consider all credible and relevant information" in a rulemaking proceeding.</u>

EPA has repeatedly emphasized that the Agency is required to consider other information, in addition to the IRIS database, when evaluating health effects in a regulatory context. *See Community Nutrition Instit. v. Young,* 818 F.2d 943, 946 (D.C. Cir. 1987), *McLoud Steel Prods. Corp. v. EPA*, 838 F.2d 1317 (D.C. Cir. 1988); *see also* EPA, Residual Risk Report to Congress, EPA-453/R-99-001 (Mar. 1999), at 61 ("As the IRIS assessments for some HAPs are less current than others, the Agency will evaluate the appropriateness of some assessments in light of more recent credible and relevant information.").

In guidance on the use of IRIS for purposes of developing values under the early reduction program of the Clean Air Act, EPA noted:

> It is also important to remember that IRIS is not a comprehensive toxicological database. There may be more recent information available than is contained in IRIS. Moreover, the act of including a value in IRIS is not subject to notice and comment rulemaking, and may not necessarily have been subjected to external peer review.... Accordingly, IRIS values are not entitled to conclusive weight and shall not be made legally binding in the context of any other rulemaking action. In addition, EPA or any State agency that uses IRIS should not rely exclusively on IRIS values but should consider all credible and relevant information that is submitted in any particular rulemaking. If an outside party questions IRIS values during the course of an EPA proceeding..., EPA will consider all credible and relevant information before it in that proceeding.

U.S. EPA, Guidance on the Use of Integrated Risk Information System, Office of Air Quality Planning and Standards (1994).

The importance of considering all recent and relevant information instead of simply using IRIS assessment values as default values in Agency actions is echoed in an EPA Office of Solid Waste and Emergency Response (OSWER) directive, which states:

> IRIS is not the only source of toxicological information, and in some cases more recent, credible and relevant data may come to the Agency's attention.... Such information should be considered along with the data in IRIS in selecting toxicological values; ultimately, the Agency should evaluate risk based on its best scientific judgment and consider all credible and relevant information available to it.

U.S. EPA, Use of IRIS Values in Superfund Risk Assessment, OSWER Directive No. 9285.7-16 (1993).

The need for a careful examination of recent, relevant data and research in determining an appropriate toxicological value is quite evident in the case of the formaldehyde dose-response value where the IRIS dose-response value is based on a study that is over twenty years old. This fact was emphasized in the 2004 proposed rule for the National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, 40 CFR Part 63, where, in its discussion of the formaldehyde dose-response value, EPA states "the dose-response value in IRIS is based on a 1987 study, and no longer represents the best available science in the peer reviewed literature. Since that time significant new data and analysis has become available." 69 Fed. Reg. at 18333. The NAS panel's unequivocal support of the CIIT BBDR model should be considered when determining the best available science.

2. EPA's proposed rule should be based on the best available science *at the time* of the rulemaking.

EPA's reversion to the 1991 IRIS assessment value for use in the Proposed Rule not only violates its own guidance on the use of IRIS for purposes of developing toxicological values, but also fails to meet the rigorous data quality standards for "influential information" outlined in the IQA Guidelines. As stated above, the IQA Guidelines for influential information require EPA to use the best available science and supporting studies, as well as "a weight-of-evidence approach that considers all relevant information and its quality." EPA IQA Guidelines at 21. To determine what constitutes the "best available science," EPA is required to conduct a comprehensive review of the available science, and make a determination based on the weight-of-evidence. EPA overly simplified this process by determining that the only two viable dose-response values were the CIIT value and the 1991 IRIS value. EPA defaulted to the 1991 IRIS value without conducting a comprehensive review of the considerable body of research that has been conducted in the past twenty years that may suggest an alternative value that is supported by the best available science.

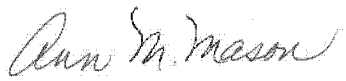
The U.S. Court of Appeals for the D.C. Circuit, in *Chlorine Chemistry Council v. EPA*, 206 F.3d 1286 (D.C. Cir. 2000), further underscored the importance of rulemaking "on the basis of the best available science *at the time* of the rulemaking." *Id.* at 1291 (emphasis in original). In holding that the best available science is the science available at the time of rulemaking, the court unanimously rejected EPA's contention that it would defer the application of the best available science until after input from the Science Advisory Board on the carcinogenic mode of action of chloroform. "The word 'available' would be senseless if construed to mean 'expected to be available at some future date.'" *Id.* Similarly, the research and data considered in the NAS Report of the Draft IRIS Assessment must be incorporated into this rulemaking; EPA cannot legally defer application of the best available science.

* * *

For the foregoing reasons, ACC asks that the EPA reject the 1991 IRIS model and its corresponding dose-response value and incorporate the CIIT dose-response value in accordance with the recommendation of the NAS panel.

If you would like to discuss any of the comments in more detail, please contact me at (202) 249-6704 or Ann_Mason@americanchemistry.com. Thank you in advance for your consideration of these comments.

Yours truly,



Ann M. Mason
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American Chemistry Council

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February 24, 2012

TO: File

FROM: Zach Emerson

RE: Hexachloroethane Emissions from Brownstock Washers and Bleach Plant Sources

Background

In EPA's December 2011 risk-modeling, hexachloroethane (HCE) emerged as a risk-driving compound from brownstock washers and bleach plant sources. After an initial review of available information on HCE emissions from these sources, NCASI has determined that reported emissions are based upon limited emissions data derived from stack tests conducted in 1993.

Many facilities have used the information presented in the NCASI Air Toxics Emissions Database (NCASI 2012) to estimate emissions of HCE from their sources. Tables 1, 2 and 3 present summaries of stack test data that form the basis for the information presented in the database.

Table 1 presents the results of HCE testing at three vacuum drum brownstock washer systems at three facilities. In testing at two softwood and one hardwood pulp mills, HCE was not detected in any vacuum drum washer vent. Emission rates (calculated using the minimum analysis measurement level) ranged from less than 0.043 to less than 0.10 lb/ADTUBP. Note that, in such cases, NCASI does not calculate a recommended emission factor and instead provides the minimum and maximum observed values.

Table 1. Hexachloroethane Emissions from Brownstock Washers – Vacuum Drum

Source Code	Year	Notes	Emissions (lb/ADTUBP)
BSWIF	1993	Softwood – 5 Vents	< 4.3 E-02
BSWIG1	1993	Softwood – 3 Hood Vents	< 8.4 E-02
BSWIG2	1993	Hardwood – 3 Hood Vents	< 1.0 E-01
Average not estimated when data set has all NDs; only min and max DLs provided			

Table 2 presents the results of HCE testing at two diffusion washer systems. HCE was reported as detected at a hardwood diffusion washer vent and in a foam breaker vent at a softwood diffusion washer system. Measured emissions ranged from 0.032 to 0.13

lb/ADTUBP with a mean emission factor of 0.081 lb/ADTUBP. Each HCE result in this dataset was labeled as "suspicious data – needs confirmation" in the Air Toxics Database. This will be discussed in more detail below. In the Air Toxics Database, this dataset is representative of the "Brownstock Washer – Other" process unit group.

Table 2. Hexachloroethane Emissions from Brownstock Washers – "Other"

Source Code	Year	Notes	Emissions (lb/ADTUBP)
BSWIC1*	1993	Hardwood – 1 Diffusion Washer Vent	1.3 E-01
BSWIC2*	1993	Softwood – Diffusion Washer 1 Foam Breaker Vent	3.2 E-02
Mean = 8.1 E-02 lb/ADTUBP			
*data is labeled "suspicious data – needs confirmation" in NCASI Air Toxics Database			

Table 3 presents the results of HCE testing at six non-ECF bleach plant vents and one ECF bleach plant vent. HCE was detected in the lone ECF bleach plant source at 0.025 lb/ADTUBP. HCE was not detected in any of the non-ECF bleach plant vents. Emission factors for the non-ECF vents ranged from less than 0.015 to less than 0.068 lb/ADTUBP.

Table 3. Hexachloroethane Emissions from Bleach Plant Vents

Source Code	Year	Notes	Emissions (lb/ADTBP)
BPIC1a	1993	Non-ECF	< 2.2 E-02
BPIC3	1993	ECF	2.5 E-02
BPIF2	1993	Non-ECF	< 4.1 E-02
BPIG	1993	Non-ECF	< 1.5 E-02
BPIJ1	1993	Non-ECF	< 1.9 E-02
BPIJ2	1993	Non-ECF	<3.8 E-02
BPIF1	1993	Non-ECF	<6.8 E-02

The current data on HCE emissions from these sources (a) is based upon limited data from pre-MACT testing, (b) is predominantly comprised of non-detects and (c) is unconfirmed in many cases due to uncertainties associated with the analytical methodology. More details are provided in the following sections.

Discussion

HCE Emissions from Low-Flow Brownstock Washers and ECF Bleach Plant Vents

Of the relevant process units, hexachloroethane emissions were detected at two diffusion washer system vents and in the lone ECF bleach plant vent. These emissions were labeled "suspect" in the emissions database. NCASI Technical Bulletin No. 973 (2010) serves as the foundational document for the Air Toxics Database; it contains the following passage regarding HCE emissions from brownstock washer sources:

> **Hexachloroethane** (HCE) – This compound was not detected in all three VDW (*vacuum drum washer, ed.*) system vents tested, with DLs ranging from 0.043 to 0.10 lb/ADTUBP. However, HCE was detected in two low-flow (diffusion) washer system vents tested at Mill IC (one hardwood and one softwood line) at levels ranging from 0.032 to 0.13 lb/ADTUBP. Since washer vent emissions are generally related to the chemicals in the liquor trapped within the brownstock or the chemicals in the last stage wash water used, neither of which should contain this chlorinated compound, it appears highly unlikely that this compound would be present. The identity of this compound was not confirmed using GC/MS. As discussed above in Section 4.1, HCE was also detected in the bleach plant scrubber vent at the same mill (Mill IC).

Regarding bleach plant vents, Technical Bulletin No. 973 also says the following:

> **Hexachloroethane** (HCE) was not detected in all six non-ECF bleach plant vents tested. However, it was detected at 0.025 lb/ADTBP in the sole ECF bleach plant tested (not identified or confirmed by GC/MS)...<u>The sole data point for HCE emissions from ECF bleach plants should be used with caution</u>. More testing would be needed to confirm its presence.

Another important factor to consider is the chemistry of hexachloroethane. It is well known that hexachloroethane dechlorinates in a reducing environment (Curtis and Reinhard 1994). Thus, there is no potential for its formation during the kraft pulping process, and it would not be expected to be present in sources such as brownstock washers, which are associated with kraft pulping. Relative to HCE formation in an ECF bleach plant, it should be noted that HCE is manufactured through the chlorination of tetrachloroethylene in the presence of ferric chloride at elevated temperature. HCE is also a co-product in the production of tetrachloroethylene by pyrolysis of carbon tetrachloride at 800-900˚C (U. S. Dept. of Health and Human Services 1997). ECF bleaching conditions do not provide conditions that are conducive to the generation of the precursors of HCE nor is there significant availability of free chlorine to further chlorinate the precursors, if they are present.

Based upon the above and our understanding that HCE is not expected to be present in pulping/bleaching additives, it is our view that there are significant uncertainties associated with the HCE emissions data in NCASI's database. NCASI is planning to conduct emissions testing studies at several facilities to evaluate this; such studies will take some time. The goal will be to test for HCE at two diffusion washer system vents and two bleach plant scrubber vents.

Summary

Until new test results become available, HCE emissions from brownstock washer sources and bleach plant vents should be removed from EPA's risk model inputs for the following reasons:

- HCE was not detected at three vacuum drum washer systems. In general, HAP emissions from vacuum drum washer vents are higher than diffusion washers. HCE was also not detected during (unquantified) screening studies at other washer system vents.
- HCE was not detected at six non-ECF bleach plant system vents.
- HCE is not expected to be present in the black liquor in the brownstock.
- HCE is unstable in highly reductive environments, such as black liquor.
- In stack tests at two diffusion washer systems and one ECF bleach plant scrubber, the suggested presence of HCE in vent gases was not confirmed on mass spectrometer.

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February 18, 2012

TO: Robin Dunkins, Sector Policies and Programs Division, OAQPS
John Bradfield, Sector Policies and Programs Division, OAQPS
Bill Schrock, Sector Policies and Programs Division, OAQPS

SUBJECT: **Interim comments on rationale and methodologies used to evaluate and propose increased treatment requirements for kraft condensates in the Pulp and Paper RTR**

This memorandum provides interim comments on the rationale and approaches used by the EPA, as part of the technology review, to propose an increase in HAP treatment efficiency from 92% to 94% and calculate numerical treatment standards. These comments are being submitted ahead of the comment deadline, after considering the tight schedule that EPA is committed to, both for review of comments on the December 27. 2011 Federal Register notice and for adoption of EPA's final determination on technology review of the Subpart S NESHAPs for the Pulp and Paper source category. It is hoped that these comments will assist EPA in accurately assessing the control performance of available technology being used for controlling kraft pulping process condensates and to correct, as previously identified, an issue with the equivalency calculation used in December 27, 2011 proposal.

As discussed in the December 27, 2011 *Federal Register* publication [FR 76 (248) 81345], EPA carried out a review of the 2011 Pulp and Paper ICR database and concluded that a majority of the mills were demonstrating greater than the 92 percent minimum level of control of kraft pulping condensates (or any equivalent demonstrations). Subsequently, EPA (a) proposed that the percent treatment requirements be increased from 92% to 94% and (b) utilized an equivalency calculation procedure to convert the proposed % treatment to numerical limits.[1]

- The comments provided here highlight the reasons why it is inappropriate to use the 2011 ICR treatment data as the basis for proposing revised percent removal and numerical treatment standards.
- Attachment A of this document further elaborates on the equivalency calculation issue, previously identified in a meeting with OAQPS on January 12, 2012, and provides two appropriate approaches to recalculating numerical limits.

[1] "Summary of Kraft Condensate Control Technology Review," EPA Memorandum to Docket – EPA-HQ-OAR-2007-0544, John Bradfield and Kelley Spence, October 23, 2011.

ED_000419-0004338

ISSUES WITH USING THE 2011 PULP AND PAPER ICR DATA TO IDENTIFY TECHNOLOGY ADVANCES, OPERATIONAL IMPROVEMENTS, AND PROPOSE INCREASED TREATMENT REQUIREMENTS

Background

OAQPS staff suggested informally, during a meeting with industry representatives on January 12, 2012, that the numerical HAP treatment requirements proposed in this rulemaking can also be justified by ICR data. This is inconsistent with rule language in the proposal which suggests that the proposed numerical limits are based on a supposed equivalency between a 94% removal rate and a lb/ODTP mass reduction. (See FR 76 (248) 81345). We therefore do not have anything in writing explaining the basis for the proposed mass removal rate requirements. This prevents the industry from commenting effectively on the December 27, 2011 proposed rule. Nevertheless, because EPA has suggested in subsequent discussions that information reported by mills in response to the Part I ICR supports the proposed rule, NCASI has attempted to analyze the ICR data to help EPA understand its significance. During the meeting with industry representatives, EPA also provided a spreadsheet summarizing the data EPA had culled from industry responses to the Part I ICR.

Since then, NCASI has been able to access the entire set of responses EPA received to the Part I ICR. In response to EPA's proposal to increase assumed stripper (or biotreatment) efficiency from 92 to 94%, NCASI has determined that the ICR data are not sufficient to support that proposal (or any increase in treatment efficiency above the current MACT standards). With respect to numerical condensate treatment levels, NCASI has analyzed the ICR responses to assess whether they could be used to support a conclusion that technology improvements would allow for more stringent condensate treatment requirements.

Discussion

In its review, OAQPS has subcategorized kraft mills based on the type of treatment performance data provided in the ICR. Specifically, OAQPS reviewed the mass treatment levels (lb/ODTP) reported by both unbleached and bleached mills to ascertain whether operational improvements had been realized by facilities. As discussed in the meeting with AFPA and NCASI on January 12, 2012, several other factors need to be considered while reviewing condensate treatment performance data reported in the ICR and attributing that data to technological or operational improvements. These other factors are provided below:

1. **Facilities using the Clean Condensate Alternative (CCA)** - For facilities complying with the HVLC system requirements under §63.443 using the Clean Condensate Alternative (CCA) (§63.447) or other "equivalency by permit" options, the reported condensate treatment levels reflect compliance with the requirements under both §63.446 and §63.447 (hereafter referred to as MACT Phase 1 and Phase 2, respectively). Therefore, it is inappropriate to attribute the combined treatment values to Phase 1 treatment requirements. (An example CCA compliance option is discussed in Attachment B).

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2. **High performance biological treatment systems** – A handful of facilities demonstrate compliance with Phase 1 by treating hardpiped condensates in high rate biotreatment systems like activated sludge treatment (AST), anaerobic treatment, or UNOX. These dedicated high rate systems can operate at higher treatment efficiencies than traditional Aerated Stabilization Basins (ASB). As a consequence, these systems are generally paired with lower lb/ODTP collection levels (closer to the 11.1 pound per ton collection requirement for bleached mills). The focus in these systems is to collect higher concentration (lower volume) condensates and minimizing flow, a significant determinant in system capital and operating costs. The trade-off is higher treatment efficiency on a smaller (more concentrated and lower volume) amount of HAP for roughly equivalent pound-per-ton-treated performance.

   When percent treatment data from these systems are combined with those of ASBs and the "combined average" is compared against the current 92% standard, there is a potential to erroneously conclude that ASBs are performing at levels above the current standard.

3. **Operational and seasonal variability in biological treatment system performance** – Facilities have the option of collecting additional condensates in their hardpipe in order to maintain compliance flexibility, i.e., demonstrate compliance using either the "percent removal" or "lb/ODTP" treatment options. Additionally, reported treatment levels also reflect safety margins required to demonstrate ongoing compliance with treatment requirements over the wide range of operational situations that exist throughout time typical pulp mills. More details on this issue are provided in Attachment C.

4. **Facilities demonstrating compliance using steam strippers** – The reported percent destruction OR percent removal numbers reflect equipment performance during one or two Initial Performance Tests (IPT). These datasets are snapshots of performance immediately following commissioning or scheduled maintenance and reflect safety factors inherent in equipment design. These design factors are essential to ensure ongoing compliance at the level of the current standard (i.e., 92%). They compensate for the gradual degradation of performance over normal maintenance cycles, largely attributable to fouling or scaling of heat transfer surfaces in contact with process condensates. Initial performance tests would, by nature, capture the high end of designed performance.

From the data requested in the ICR it would be very difficult for EPA to discern the relative importance and contributions of these factors, particularly in the context of the wide flexibility in compliance options, the design variations, and operational differences that exist among individual compliance systems. Recognizing this, responding companies had requested that EPA confer with them in analyzing the data in order to ensure that conclusions reflected a thorough understanding of process variations and realities.

The ICR data provided by OAQPS has been analyzed in order to further illustrate the points reiterated above. Facilities have been divided into three categories for this analysis:

A. Mills reporting only percent removal in biotreatment systems (no lb/ODTP treatment data)
B. Unbleached mills reporting mass treatment (lb/ODTP) levels
C. Bleached mills reporting mass treatment (lb/ODTP) levels

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Background on r-factor and non-methanol HAP treatment when using the biotreatment Option

Facilities demonstrating compliance with methanol/HAP treatment requirements using the biotreatment option are required to also treat non-methanol HAPs to the same treatment level achieved in steam strippers. The following approach was developed by EPA, in conjunction with industry and NCASI representatives, during the original MACT rulemaking and is now used to establish "treatment equivalency" when using the biotreatment option:

1. NCASI characterization studies of kraft condensates identified that acetaldehyde, methyl ethyl ketone (MEK), and propionaldehyde are the predominant non-methanol compounds that exist at concentrations > 1 ppm. These studies also identified ranges for r-factors (refer to Attachment C for a detailed explanation) in kraft condensates.

2. During the timeframe of the original rulemaking, there were uncertainties in quantifying and estimating the biotreatment efficiencies for major non-methanol HAPs. Facilities were therefore given, as part of the rules, the following option to demonstrate equivalency:
    a. As a worst case, assume 0% treatment efficiency for non-methanol HAPs in biotreatment systems.
    b. In lieu of treating these non-methanol HAPs, demonstrate equivalency by treating an additional quantity of methanol equivalent to the amount of non-methanol HAPs.

    This equivalency demonstration in effect means that, in order to demonstrate an ***effective*** methanol treatment efficiency of 92% ($F_{bio,\ adjusted}$), the ***actual*** methanol treatment efficiency ($F_{bio,\ methanol}$) would have to be at 94%. The ***actual*** methanol removal efficiency has to be higher in order to account for the roughly 2% of non-methanol HAPs that would have been treated to some degree in reality but could not be measured as an on-going compliance technique.[2] (More details on this calculation are provided in Attachment D).

A. Mills Reporting Percent Removal in Biotreatment Systems

The discussion provided below is summarized on a mill by mill basis in the "% ASB Removals" tab of the accompanying MS Excel spreadsheet

1. Among the 16 facilities reporting only *percent removal* efficiencies, the following applies
    a. 5 facilities operate UNOX systems
    b. 4 facilities operate Activated Sludge treatment systems, and
    c. 3 facilities comply with MACT 1 Phase 2 using CCA. Therefore, the treatment efficiencies reported by these facilities also reflect compliance with both MACT I Phase 1 and 2 standards.

[2] Using a nominal mass ratio of non-methanol HAPs to methanol HAPs (defined as the r-factor) of 0.02, $F_{bio,\ methanol}$ = 94% in order to achieve an adjusted F_{bio} of 92%

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2. **With the facilities described above removed from this analysis, only 4 mills** remain with reported biotreatment efficiencies corresponding to the requirements under MACT I Phase 1 only. It is inappropriate to use performance data from such a limited number of mills as the basis for identifying operational improvements or proposing revised standards. The following additional aspects are pertinent:
    a. The average $F_{bio,\ methanol,}$ calculated from limited quarterly performance data provided in the ICR, was 95.7 at these 4 mills.
    b. As discussed earlier, the ***actual methanol removal efficiency*** ($F_{bio,\ methanol}$) has to be ~94% in order for facilities to demonstrate compliance with the 92% standard (to account for non-methanol HAPs).
    c. Given the seasonal and operational variability inherent in biotreatment systems (~5% variability in percent treatment efficiency as shown from data in Attachment C), this average falls within the range of operating variability and as such is inappropriate to be the basis for revising the treatment standard.

<u>Conclusion</u>[3]

- Only 4 mills have reported percent removals in biotreatment systems that (a) are representative of Phase 1 compliance and (b) can be compared against the current requirement of 92%. This is too limited a list from which to draw substantive conclusions on over-performance.
- Additionally, the percent removal data do not indicate control levels in excess of current requirements (compared against the **actual** $F_{bio,\ methanol}$ of 94%).
- This information cannot be the basis for revising the current percent removal standards.

B. Unbleached mills reporting mass treatment levels (lb/ODTP)

The discussion provided below is summarized on a mill by mill basis in the "unbleached lb.ODTP" tab of the accompanying MS Excel spreadsheet

1. Among the 22 unbleached mills reporting *lb/ODTP removal* numbers, the following applies
    a. 13 facilities comply with MACT 1 Phase 2 using CCA
    b. 2 facilities operate high rate UNOX/AST/anaerobic systems
    c. 4 facilities have unique site-specific operating and compliance scenarios (details below)

2. Four (4) facilities with unique, site-specific, operating and compliance scenarios
    a. NEI47104 – Subset of condensates is routed to the steam stripper (achieves 50% removal). Condensates from the steam stripper are subsequently routed to the hardpipe.

[3] These conclusions (and the ones for unbleached mills and steam strippers below) address only the treatment issue and does not speak to the other technical and economic aspects. AF&PA and NCASI are working on more detailed comments on the need for compliance flexibility, the inherent variability in condensate collection levels, and relevant economic arguments. For example, at the January 12 meeting, industry characterized the cost of complying with higher treatment efficiencies as several hundreds of millions of dollars (see page 37 of the meeting handout) which is an order of magnitude more than EPA has estimated.

b. NEI6057 – Facility operates a biotreatment system with seasonal/operational variability (with $F_{bio, methanol}$ dropping to ~ 86% in some quarterly performance tests). Over-collection margins are therefore utilized to demonstrate compliance.
c. NEI18657 – Facility has reported only one set of data from quarterly performance tests ($F_{bio, methanol}$ = 86.4%). Over-collection margins are therefore utilized to demonstrate compliance.
d. NEI 26495 utilizes both the steam stripper and biotreatment to demonstrate lb/ODTP treatment levels.

3. **With the facilities described above removed from this analysis, only 3 mills** remain with reported lb/ODTP treatment values corresponding to the requirements under Phase 1. Once again, it is inappropriate to propose revised standards based on performance data from such a limited number of mills.

4. As anticipated, the average treatment level for the remaining 3 MACT I Phase 1 mills (8.2 lb/ODTP) is statistically different from the average treatment level reported by the 13 CCA mills (10.5 lb/ODTP) on this list.

Conclusion

Only 3 facilities remain on the list with reported *lb/ODTP treatment levels reflective of Phase 1 compliance.* Data from such a limited number of facilities cannot form the basis for revising the numerical condensate treatment standards.

C. Bleached mills reporting mass treatment levels (lb/ODTP)

The discussion provided below is also summarized on a mill-by-mill basis in the "bleached lb.ODTP" tab of MS Excel spreadsheet

1. Among the 35 bleached mills reporting *mass removal (lb/ODTP)* numbers, the following applies
   a. 14 facilities comply with MACT 1 Phase 2 using CCA
   b. 3 facilities operate high rate UNOX, anaerobic, or AST systems
   c. 15 facilities demonstrate compliance using steam strippers. As discussed earlier, control device performance data from steam strippers are obtained from initial performance test data.
   d. 2 out of the 3 facilities that remain have unique site-specific operating and compliance scenarios (details below).

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2. Two of the three remaining facilities have unique, site-specific, operating and compliance scenarios
    a. NEI41628 – This bleached kraft mill operates only batch digesters. All condensates from the Blow Heat system are collected and sent to the hardpipe. Because of the batch operation, condensate collection numbers are highly variable. The ASB operates at ~ 70% Fbio, methanol.
    b. NEI45474 – Collects *all named condensate streams* in the hardpipe and routes it to the ASB

3. **Even without discounting the 2 unique scenarios described above, only 3 mills** have reported lb/ODTP treatment values corresponding to the requirements under MACT I Phase 1. Once again, it is inappropriate to base revised standards on limited performance data from such a limited number of mills.

<u>Conclusion</u>

- For facilities employing Steam Strippers, reported treatment levels reflect equipment performance during one or two Initial Performance Tests (IPT). These datasets reflect performance immediately following commissioning or scheduled maintenance and reflect safety factors inherent in equipment design. These factors are incorporated during equipment design and are essential to ensure ongoing compliance at the level of the current standard (i.e., 92%).
- Given the limited number of mills remaining on this list, it is inappropriate to use treatment information available from these mills as the basis to revise the condensate treatment standards.

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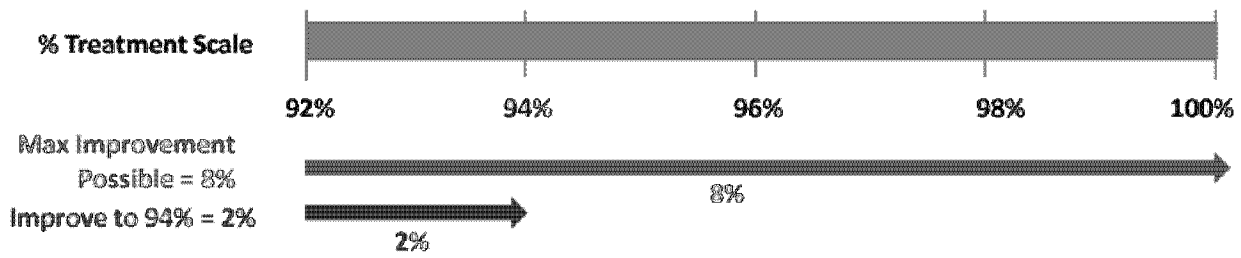
ATTACHMENT A

EQUIVALENCY CALCULATION USED TO ESTABLISH NUMERICAL (LB/ODTP) TREATMENT LIMITS FOR KRAFT PROCESS CONDENSATES

NCASI and AF&PA have previously pointed out to EPA that the numerical HAP treatment levels EPA has proposed, supposedly reflecting an increase in methanol removal efficiency from 92% to 94%, are greater than the current HAP collection requirements (e.g., 40 C.F.R. § 63.446(c)(3) allows bleached and unbleached kraft mills to comply with condensate standards by collecting for treatment condensates from listed equipment that contain a total HAP mass of 11.1 lb/ODTP or more, or 7.2 lb/ODTP or more, respectively. Yet, the proposed sections 63.443(e)(4) and (5) would require those mills to demonstrate that they are removing at least 12.8 lb/ODTP or 8.3 lb/ODTP, respectively). The proposal to increase the required HAP reduction (e.g., from 10.2 lb/ODTP in the current rule to 12.8 lb/ODTP, for bleached kraft mills and from 6.6 lb/ODTP in the current rule to 8.3 lb/ODTP, for unbleached kraft mills) is not consistent with the proposed rule's stated basis: an assumption that the removal efficiency can be increased from the 92% to 94%.

In the equivalency calculation used to arrive at these numerical limits, EPA has calculated the percent increase in control for each 1% increase in treatment efficiency from 92% to 98% (the level of control achieved for mills choosing the condensate recycling option). The rationale is represented graphically below:



The percent ***"standard improvement"*** [4] corresponding to an increase in treatment efficiency from 92% to 94% would be:

- 2% of the maximum possible 8% = 2/8 = 25%

Using this approach, the percent ***"standard improvement"*** for each 1% increase in treatment efficiency (from 93% to 98%) would be:

- At 93% - 1% of max possible 8% = 1/8 = 12.5%
- At 94% - 2% of max possible 8%: 2/8 = 25%
- At 95% - 3/8 = 37.5%

[4] "Summary of Kraft Condensate Control Technology Review," EPA Memorandum to Docket – EPA-HQ-OAR-2007-0544, John Bradfield and Kelley Spence, October 23, 2011, page 4.

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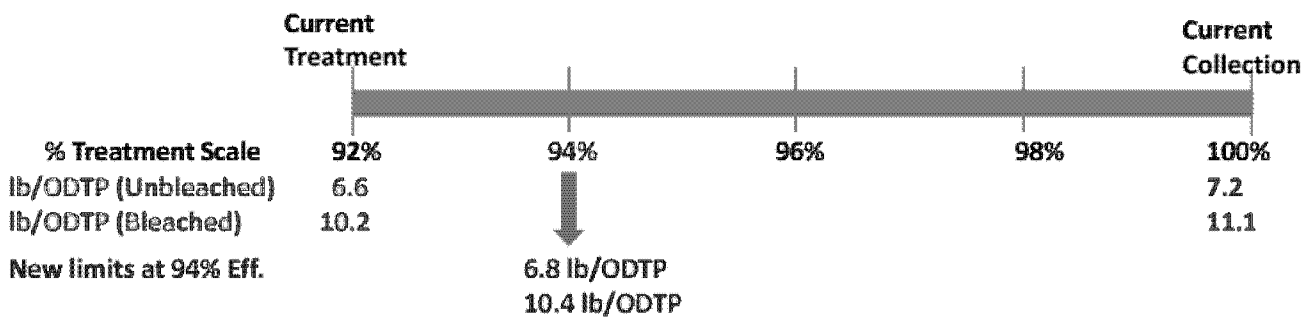
These percent ***"standard improvements"*** were subsequently directly applied as scaling factors to arrive at numerical treatment limits (Table 2 in the October 23, 2011 Memo, reproduced here).

		Recalculated Numerical Limits (lb/ODTP)	
% Treatment (% control improvement)	**Multiplication Factor Used**	**Bleached Mills**	**Unbleached Mills**
92%		10.2	6.6
93% (12.5%)	1.125	11.5 (= 10.2 x 1.125)	7.4 (= 6.6 x 1.125)
94% (25%)	1.250	12.8 (= 10.2 x 1.25)	8.3 (= 6.6 x 1.25)
95% (37.5%)	1.375	14.0	9.1
96% (50%)	1.500	15.3	9.9
97% (62.5%)	1.625	16.6	10.7
98% (75%)	1.750	17.9	11.6

As discussed during the meeting between OAQPS and the Industry Group on Jan 12, 2012, this methodology of calculating numerical limits is inconsistent with the premise behind the equivalency approach. Key insights from the equivalency approach highlight this issue:

- The scale ranging from 92% to 100% is the treatment scale
- Assuming that whatever is not treated/controlled is released as emissions, emissions would reduce from 8% to 0% as treatment increases from 92 to 100%
- The percent ***"standard improvements"*** calculated above are, in effect, ***emissions reductions.***
- In other words, a 2% increase in the numerical treatment efficiency standard is equivalent to a 25% reduction in associated emissions.
- When calculating numerical treatment limits, the applicable scaling factors should therefore reflect the original ***treatment*** scale and not the percent ***"standard improvement" (emissions)*** scale. As done in the original rulemaking, the lb/ODTP treatment requirement is simply calculated by multiplying the collection requirement by the proposed percent control efficiency as shown below.



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Recalculating the Numerical Treatment Standards for Kraft Process Condensates

The numerical treatment standards corresponding to the 94% treatment level can be calculated directly as shown below. They are represented on the treatment scale above.

- 7.2 lb/ODTP x 0.94 = **6.8 lb/ODTP** for unbleached mills
- 11.1 lb/ODTP x 0.94 = **10.4 lb/ODTP** for bleached mills

An alternate approach to calculating these numerical treatment levels that is logically consistent with applying EPA's statements about increasing treatment efficiency from 92 to 94 percent using the percent ***"standard improvement"*** scale would be as follows:

- Collection levels are 7.2 lb/ODTP and 11.1 lb/ODTP (unbleached and bleached respectively)
- At 92%, the treatment levels are 6.6 lb/ODTP and 10.2 lb/ODTP
- Therefore, when increasing the treatment standard from 92% to 94%, you achieve a ***25 percent "standard improvement" (reduction in emissions)***
    - 6.6 + ***25% of*** (7.2 – 6.6) = **6.8 lb/ODTP** - unbleached mills
    - 10.2 + ***25% of*** (11.1 – 10.2) = **10.4 lb/ODTP** - bleached mills

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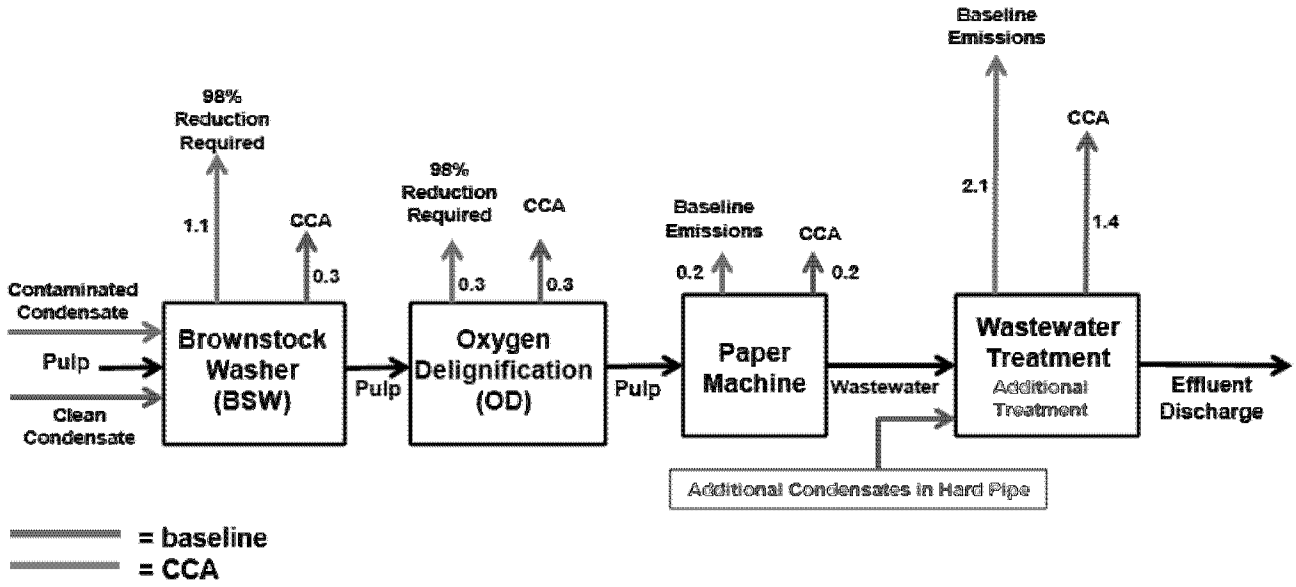
Attachment B

Example Compliance Option for the Clean Condensate Alternative (CCA)



The hypothetical bleached mill above utilizes the hardpiping option to comply with MACT 1 Phase 1 and employs the following CCA compliance strategy. Emission reductions are achieved as follows:

1. In lieu of contaminated condensates, the mill uses clean condensates OR fresh water on BSW showers. Some emission reductions are therefore realized from the BSW area.
2. The mill collects additional condensates and re-routes these condensates to the ASB.
3. Mill may also complete voluntary upgrades to the ASB in order to achieve increased biotreatment efficiencies (over and above those required to demonstrate compliance with MACT I Phase 1). This results in additional emission reductions from the ASB
4. **The total emission reductions achieved (from BSW and ASB in this case) should be ≥ emission reductions achieved by HVLC control (98% of HVLC source emissions).**

Source	Baseline Emissions, lb/ODTP	CCA Emissions, lb/ODTP	Emission Reductions, lb/ODTP
BSW	1.1	0.3	0.8
Oxygen Delignification	0.3	0.3	
Paper Machine	0.2	0.2	
Wastewater Treatment System (ASB)	2.1	1.4	0.7
Total	3.7	2.2	1.5

By comparison, emission Reductions from HVLC control = 0.98 x (1.1 + 0.3) = 1.37 lb/ODTP

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Attachment C

"Intra-mill" variability in Quarterly Performance Tests to estimate $F_{bio,\ methanol}$

Site ID	Quarterly PTs, Fbio, Methanol				Average
NEI11338	0.860	0.890	0.950	0.57	0.900
NEI12492		0.932	0.939	0.924	0.932
NEI13340	0.954	0.921	0.915	0.916	0.927
NEI18334	0.974	0.975	0.987	0.979	0.979
NEI18335	0.964	0.910	0.936	0.951	0.940
NEI18338	0.985	0.978	0.917	0.933	0.953
NEI18652	0.975	0.976	0.963	0.944	0.965
NEI18658	0.996	0.997	0.991	0.998	0.995
NEI18660	0.860	0.970	0.910	0.890	0.908
NEI26506	0.940	0.970	0.960	0.940	0.953
NEI26514	0.999	0.999	0.999	0.998	0.999
NEI26526	0.970	0.970	0.970	0.970	0.970
NEI26581	0.994	0.992	0.995	0.990	0.993
NEI34070	0.977	0.893	0.897	0.987	0.938
NEI40600	0.996	0.997	0.993	0.996	0.995
NEI41314	0.970	0.990	1.000	1.000	0.990
NEI41552	0.950	0.950	0.930	0.920	0.938
NEI41628	0.704	0.690	0.740	0.750	0.721
NEI42357	0.920	0.986	0.989	0.995	0.973
NEI42410	0.786	0.736	0.843	0.898	0.816
NEI47091	0.986	0.961	0.974	0.980	0.975
NEI47104	0.727	0.975	0.981	0.960	0.972
NEI6057	0.864	0.983	0.942	0.973	0.941
NEI6450	0.991	0.991	0.991	0.991	0.991

The above Table is a compilation of data from 4 quarterly performance tests (mostly from reporting year 2009) provided in the ICR for all the hardpiping and CCA mills.

- Excluding obvious outliers and treatment conditions corresponding to process upsets (coded in Red), the average "intra-facility" variability in $F_{bio,\ methanol}$ was ~ 5%.
- This is considered to be a reasonable measure of operational variability in ASBs. In other words, for an ASB operating at an $F_{bio,\ methanol}$ of 94%, it is reasonable to expect operational variability of ~ 5% in treatment efficiencies.

The implication – facilities demonstrating compliance using ASBs need both condensate over-collection and compliance flexibility in order to demonstrate compliance with the treatment requirements.

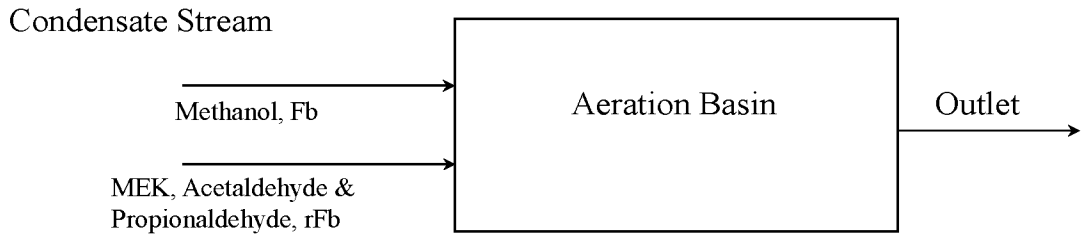
ED_000419-0004349

Attachment D

r-factor and its impact on $F_{bio,\ methanol}$

OAQPS had requested for additional technical information on the development of the r-factor and related equations. The following summary provides this information.

Background behind r-factor development and % removal equations



$$r = \frac{\text{MEK + Acetaldehyde. + Propionaldehyde}}{\text{Methanol}}$$

Given the difficulty in quantifying and modeling the biotreatment efficiencies for major non-methanol HAPs, facilities using the biotreatment option agreed to the following approach during the original MACT rulemaking:

- Assume that non-methanol HAPs are not destroyed in the ASB
- In lieu of non-methanol HAPS, treat an additional amount of methanol that is equivalent to 100% of non-methanol HAPs in condensates (= r F_b)

Therefore, the methanol treatment requirement would be as follows:

$$\mathbf{0.92\ F_b + rF_b} \qquad (1)$$

where,

0.92 F_b	=	methanol treatment level applied towards the compliance requirement
rF_b	=	additional methanol treatment to compensate for non-methanol HAPs

At the required collection levels, F_b = 7.2 lb/ODTP and 11.1 lb/ODTP respectively, for unbleached and bleached mills.

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Therefore, the actual methanol treatment requirements would be

Unbleached mills:	**6.6 + 7.2r**	(2)
Bleached mills:	**10.2 + 11.1r**	(3)
% Treatment requirements:	**92% + 100r**	(4)

As indicated by Equation 4, for a mill demonstrating compliance with the 92% MACT I Phase 1 requirement (and an r-factor of 0.02), the actual $F_{bio,\ methanol}$ = 92+0.02 x 100 = 94%

For an ASB achieving an actual methanol treatment efficiency of $F_{bio,\ methanol}$, the treatment requirement equation can be written as follows:

$$F_b \times F_{bio,\ methanol} = 0.92\ F_b + r\ F_b \qquad (5)$$

In other words,

$$0.92F_b\ (1 + r/0.92) = F_b \times F_{bio,\ methanol}$$

Or

$$0.92F_b\ (1 + 1.087\ r) = F_b \times F_{bio,\ methanol} \qquad (6)$$

In equation (6), the amount of methanol treated (towards Phase 1 requirements) = 0.92 F_b

Therefore

$$F = (F_b \times F_{bio,\ methanol})/(1+1.087\ r)$$

Impacts of the proposed rulemaking on this compliance demonstration procedure:

- A revised % treatment level (94%) would result in a modified equation (1) and, subsequently, a modified adjustment factor (instead of the current factor of 1.087).
- Removing MEK from the calculation of r-factors would result in different values for the r-factor.

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ATTACHMENT 5

Cost Estimate of Potential Changes to 40 CFR 63 Subpart S
Condensate Collection & Treatment

Current Condensate Treatment Options used by Kraft Mills

Stripping	43
Biological Treatment	39
Biological Treatment & Stripping	9
Recycle	5
Thermal Incinerator	1
CCA [6]	38
CCA (dependent upon condensates or clean water substitution) [6]	34

Assumptions		Units	Notes
Stripper Capital Cost (Stand-Alone Unit)	$ 7,400,000	$	3
Stripper Upgrade (Integrated Unit)	$ 5,800,000	$	28
Stripper Upgrade (Stand-Alone Unit)	$ 2,900,000	$	27
New/Replaced Stripper Energy Rating	120	MMBtu/hr	1
Stripper Hours of Operation	8390	hrs/yr	7
Energy Cost	3	$/MMBtu	8
Incremental Energy Required for Stripper for Treatment Increase only	12	MMBtu/hr	9
Annual Maintenance for New Strippers	$ 250,000	$/yr	10
Additional Stripper Maintenance Costs for Existing Strippers	$ 100,000	$/yr	11
Cost to Upgrade Aeration at WWTS	$ 6,000,000	$	30
Power Cost	$ 0 07	hp/hr	3 - ($0.10/kWh)
Annual Power Costs for New Aerators	$ 2,300,000	$	30
Annual Maintenance Cost for WWTS Upgrades	$ 220,000	$	30
Nutrient Costs	$ 60,000	$/yr	15
Installation of HVLC System with Single Treatment Device	$ 15,000,000	$	19
Cost to collect additional condensates	$ 3,000,000	$	13
Cost to convert collection compliance approach from lb./ton to 65%	$ 1,000,000	$	13

Only Increase Treatment Requirement	Notes	Number of Units Affected	Capital Cost	Annual Energy Cost	Annual Maintenance Cost	Total Annual O&M Cost Increase
Stripper Upgrade	20, 29	27	$ 94,000,000	$ 8,200,000	$ 2,700,000	$ 10,900,000
Stripper Installation/Replacement	20	0	$ -	$ -	$ -	$ -
Current Strippers (Energy Only)		25	$ -	$ 7,600,000	$ 2,500,000	$ 10,100,000
Aeration	21	39	$ 230,000,000	$ 89,700,000	$ 8,600,000	$ 98,300,000
Nutrient Addition	21	39	$ -	$ -	$ 2,300,000	$ 2,300,000
HVLC Collection to Single Treatment Device	24	0	$ -			
Total Cost			**$ 324,000,000**	**$ 105,500,000**	**$ 16,100,000**	**$ 121,600,000**

Increase Collection and Treatment Requirements	Notes	Number of Units Affected	Capital Cost	Annual Energy Cost	Annual Maintenance Cost	Total Annual O&M Cost Increase
Stripper Upgrade	20	27	$ 94,000,000	$ 8,200,000	$ 2,700,000	$ 10,900,000
Stripper Installation/Replacement	20	0	$ -	$ -	$ -	$ -
Current Strippers (Energy Only)		25	$ -	$ 8,200,000	$ 2,500,000	$ 10,700,000
Aeration	21	39	$ 230,000,000	$ 89,700,000	$ 8,600,000	$ 98,300,000
Nutrient Addition	21	39	$ -	$ -	$ 2,300,000	$ 2,300,000
HVLC Collection to Single Treatment Device	22	34	$ 510,000,000	$ -	$ -	$ -
Total Cost			**$ 834,000,000**	**$ 106,100,000**	**$ 16,100,000**	**$ 122,200,000**

EPA did not include any information in the preamble to the Dec. 27, 2011 proposed rule or in the docket describing how EPA expected mills to comply with the new proposed new condensate treatment standards. Therefore, AF&PA carefully examined what would be necessary to comply with the proposal. It should be noted that all cost estimates in these comments are based on the best information available, given the limited time to gather data during the 60 day comment period. These are based on conservative estimates of upgrades and number of units affected and not detailed mill-by-mill engineering estimates. Even with these caveats, the estimates are an order of magnitude higher than EPA's. These estimates are somewhat different from those presented to OAQPS on January 12, 2012, because AF&PA made further refinements and gained more information from member companies.

ATTACHMENT 5

Cost Estimate of Potential Changes to 40 CFR 63 Subpart S
Condensate Collection & Treatment

Notes

1. Based on typical steam requirements at mills that currently have steam strippers
2. Assume recycle and thermal incinerator mills will not be affected by treatment increase. Only affected by collection increase
3. Based on cost estimate for stand-alone stripper installation for member company in 1998 dollars adjusted to 2012 dollars.
4. Assumes Mills that treat only with WWTS will require "New Strippers." Mills that have strippers are included in the upgrade/replacement categories
5. Mills that only treat with WWTS and do not install strippers will require WWTS improvements
6. Note that CCA Mills are a subset of Mills that have another form of treatment
7. Based on the Stripper being down 15 days/yr. With need to sustain a higher treatment efficiency, it will be necessary to clean preheaters or install spare preheaters (equipment that will foul) in additional to the annual outage.
8. URS Memo to AF&PA, " Cumulative Cost Burden Analysis of Air Regulations Potentially Impacting the Forest Products Industry", August 2011.
9. Assumes energy requirement for additional stream is 10% of an existing unit, based on a need for a sustained increase of 2% treatment efficiency
10. Mills will need to have an annual outage for stripper maintenance (10 days)
11. Assume must shutdown stripper for maintenance one additional time per year to maintain increased treatment efficiency. Hydroblasating is approximately $50K plus labor, materials, etc. (5 days)
12. Assumes that existing WWTS have the electric capacity to install additional aerators (no new Motor Control Centers) and dredging will not be necessary for installation.
13. Based on estimate from member company
14. Will need to increase aerator hp by 25% to achieve an additional 2% in treatment efficiency
15. Assume add Nutrients (Nitrogen and Phosphorus containing nutrients 1/quarter for upsets at a cost of $15 K/quarter)
16. Costs developed by Rich Lowe, URS Corporation, January 2012.
17. Assumes dredging material to allow for another day of retention time based on average flow of 19 2 MGD
18. Average wastewater flow from ICR Data collected from NCAS
19. Cost ranges from $10-20MM. Assumes that 4% vent allowance remains
20. Based on EPA estimates of systems that will need to be upgraded, Memo from RTI to EPA, November 17, 2001, "Cost and Environmental and Energy Impacts for Subpart S Risk and Technology Review. Assumed all mills with only Stripper Treatment at or below 96% (23 mills) will need upgrades. Of the 6 mills with stripping/bio and the 2 mills with stripping/recycle - 1/2 will need to upgrade their stripper.
21. Based on all biological treatment systems requiring upgrades to meet 94% treatment, which equates to an Fbio for methanol of 96%. Assume these mills will need to increase aeration and nutrient addition.
22. Assume all CCA Mills will need to install HVLC controls (assumes all CCA mills using lb./ODTP treatment approach at 4% vent allowance remains). Note that data was not available to determine the O&M costs for these systems. From EPA's information, it appears the CCA approach for 4 mills will not be affected.
23. Assumes that all Mills that utilize the lb./ODTP collection approach will convert to the 65% collection approach. Conversion based on cost from member company. Note that data was not available to determine the O&M costs for these systems.
24. For increased treatment from 92% to 94% only for Phase I (no increase in collection), assume that all CCA Mills will be able to comply if only upgrade their treatment devices.
27. Stripper upgrade costs based on cost from a AF&PA member facility for an upgrade to a non-integrated stripper in 2010

28. Assumed that the cost to upgrade an integrated stripper is double to upgrade a stand-alone unit. It is unknown if it is even possible to upgrade an integrated stripper, or if another stripper would need to be installed. These costs are a best estimate given the limited time for analysis.

29. Based on a limited survey of AF&PA members, it is assumed that 10 of the currently installed strippers (52 total) are integrated rather than stand-alone units. For these cost estimates, it is assumed that if upgrades are required, 20% of the units will be integrated and 80% of the units will be stand-alone.
30. An AF&PA member company calculated high level estimates for four facilities. This was the average cost for aeration upgrades at those facilities. Note this estimate is not refined given the time to respond to EPA's comments.

ATTACHMENT 5

Cost Estimate of Potential Changes to 40 CFR 63 Subpart S
Elimination of Excess Emission Allowances

Assumptions		Units	Notes
Current Condensate Treatment Options used by Kraft Mills	$ 5,000,000	$	24
Install redundant collection/control systems to eliminate venting	$ 7,500,000	$	25
Stripper Capital Cost	$ 7,400,000	$	3

	Notes	Number of Units Affected	Capital Cost
HVLC Redundant Control Costs	24	97	$ 500,000,000
Redundant LVHC/HVLC Collection Systems	25	97	$ 700,000,000
Back-up Strippers	26	52	$ 400,000,000
TOTAL			$ 1,600,000,000

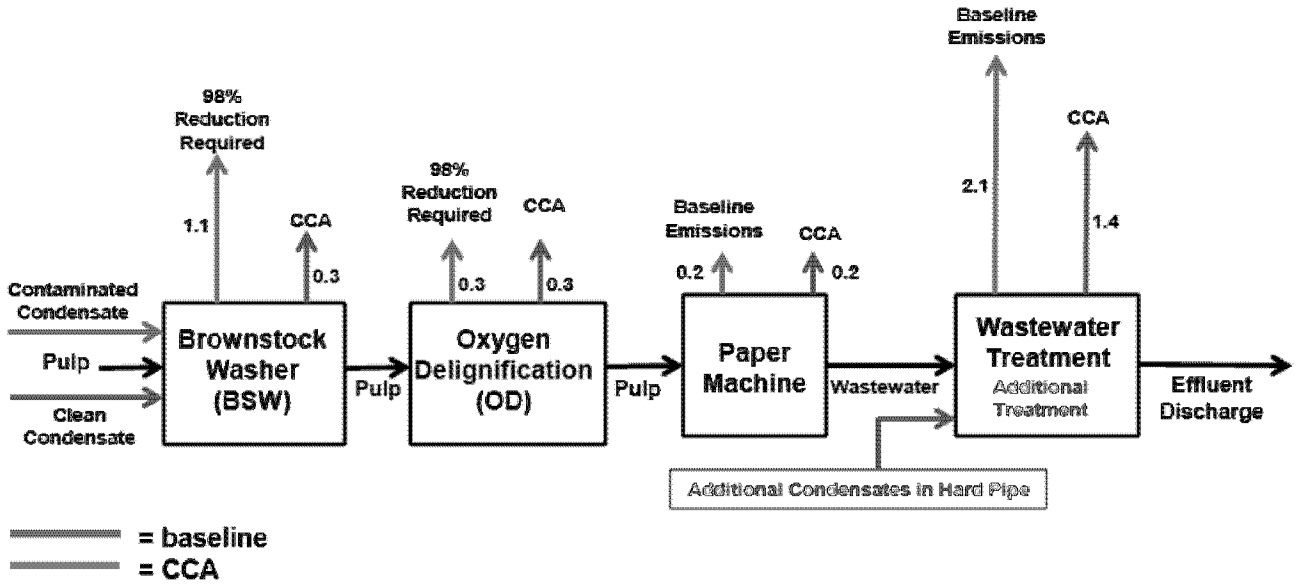
EPA did not include any information in the preamble to the Dec. 27, 2011 proposed rule or in the docket describing what EPA believes mills would have to do to comply if EPA modified or eliminated the excess emission allowances in 40 CFR 63.443(e), 63.446(g), and 63.459(b)(11)(ii). Therefore, AF&PA carefully examined what changes mills might need to make if the excess emission allowances were removed. (Obviously, it is impossible even to speculate what costs would be incurred if the excess emission allowances were modified, since EPA gave no hint of how it might modify them.) It should be noted that all cost estimates in these comments are based on the best information available, given the limited time to gather data during the 60 day comment period. These are based on conservative estimates of upgrades and number of units affected and not detailed mill-by-mill engineering estimates. These estimates are somewhat different from those presented to OAQPS on January 12, 2012, because AF&PA made further refinements and gained more information from member companies.

Notes

24. Assumes all units will need to have a backup incineration device and this device is available (i.e., no new incinerator, oxidizer, etc.)
25. Redundant collection systems necessary to eliminate venting. The cost per facility during MACT I Phase I was $5-10 M.
26. Assumes that all facilities with a stripper will need to install a back-up stripper for control.

Attachment 6

Example Compliance Option for the Clean Condensate Alternative (CCA)



The hypothetical bleached mill above utilizes the hardpiping option to comply with MACT 1 Phase 1 and employs the following CCA compliance strategy. Emission reductions are achieved as follows:

1. In lieu of contaminated condensates, the mill uses clean condensates OR fresh water on BSW showers. Some emission reductions are therefore realized from the BSW area.
2. The mill collects additional condensates and re-routes these condensates to the ASB.
3. Mill may also complete voluntary upgrades to the ASB in order to achieve increased biotreatment efficiencies (over and above those required to demonstrate compliance with MACT I Phase 1). This results in additional emission reductions from the ASB
4. **The total emission reductions achieved (from BSW and ASB in this case) should be ≥ emission reductions achieved by HVLC control (98% of HVLC source emissions).**

Source	Baseline Emissions, lb/ODTP	CCA Emissions, lb/ODTP	Emission Reductions, lb/ODTP
BSW	1.1	0.3	0.8
Oxygen Delignification	0.3	0.3	
Paper Machine	0.2	0.2	
Wastewater Treatment System (ASB)	2.1	1.4	0.7
Total	3.7	2.2	1.5

By comparison, emission Reductions from HVLC control = 0.98 x (1.1 + 0.3) = 1.37 lb/ODTP

ATTACHMENT 7

ESTABLISHING AVERAGING PERIODS FOR CONDENSATE HAP COLLECTION

Ashok K. Jain, NCASI

Studies have shown that there is high variability in the methanol content of condensate streams at kraft mills. Consequently, mills which elect the lb/ODTP option to comply with the condensate collection and treatment requirement must have a reasonable averaging time to demonstrate compliance during the initial performance test and any subsequent compliance test. The averaging time has to be established prior to the initial performance test to allow the mill to develop its compliance plan and performance test procedure. Based on available data, a number of states are considering a 15 to 30 day averaging period as reasonable for compliance demonstration. However, in some cases a statistical approach is considered more appropriate. This document discusses one such statistical approach and provides a simple method for establishing the averaging time for demonstrating compliance with the lb/ODTP option.

The averaging time required to achieve a certain probability of compliance with the lb/ton standard is affected by two parameters: standard deviation of stream methanol content and percent over-collection of methanol. For example, a mill which is required to collect 11.1 lb MeOH/ODTP and on an average collects 12.1 lb MeOH/ODTP with a standard deviation of 6.05 lb MeOH/ODTP (RSD = 50%) would have a compliance probability of 56.6% if the averaging time was one day. The compliance probability for the 1-day averaging period would increase if the standard deviation was lower, as shown in Table 1. To achieve 95% compliance probability, the standard deviation would have to be 0.66 lb MeOH/ODTP. However, methanol is a byproduct of pulping, and the daily variability in the methanol content of the condensate streams is a function of process parameters such as furnish, cooking conditions and process operating parameters which may not be controlled.

One way of reducing the variability in the methanol content of condensate streams is to increase the averaging period. According to the Central Limit Theorem, "if random samples of n observations are drawn from a population with mean μ and standard deviation, σ, then when n is large, the sample mean will be approximately normally distributed with mean equal to μ and standard deviation $\sigma/\sqrt{n}$. The approximation will become more and more accurate as n becomes larger."[1] Thus, if we consider that the stream methanol content data are random and normally distributed, as the number of days in the averaging period would increase, the standard deviation of average methanol contents of various streams would decrease and the probability of compliance with the standard would increase. For the example mill, Table 2 shows that as the number of days in the averaging period increased, the standard deviation decreased and the probability of compliance increased. The probabilities in Table 2 have been calculated using normal data distribution.

[1] Mendenhall, W. 1971. *Introduction to Probability and Statistics, Third Edition*. Belmont, CA: Duxbury Press.

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Table 1 Compliance Probability as a Function of Standard Deviation (9.6% over-collection, 1-day average)

Standard Deviation, lb MeOH/ODTP	Compliance Probability, %
6.05	56.6
4.00	59.9
3.10	62.7
1.50	74.8
1.00	84.1
0.60	95.2

Table 2 Compliance Probability as a Function of Averaging Time

Averaging Time, days	Standard Deviation, lb MeOH/ODTP	Compliance Probability, %
1	6.05	56.6
5	2.71	64.4
10	1.91	69.9
15	1.56	73.9
20	1.35	77.0
25	1.21	79.6
30	1.10	81.7

The second parameter which affects compliance probability is the degree of over-collection. Table 3 shows example calculations of compliance probabilities for various collection levels for a bleached mill required to collect 11.1 lb MeOH/ODTP with a standard deviation of collection of 3.6 lb MeOH/ODTP. Table 3 shows that as over-collection increased, the probability of compliance with the 11.1 lb MeOH/ODTP collection requirement increased.

Table 3 Compliance Probability as a Function of Over-collection

MeOH Collected, lb/ODTP	Standard Deviation, lb MeOH/ODTP	Compliance Probability, %
12.0	3.60	59.9
12.5	3.60	65.3
13.0	3.60	70.1
13.5	3.60	74.8
14.0	3.60	79.0

The above discussion suggests that in order to have a high probability of compliance with the collection requirement, a combination of standard deviation and over-collection has to be considered. These parameters, however, vary significantly from mill to mill, making it difficult to establish certain minimum acceptable values. One approach which may be used is to establish an averaging period which would ensure a certain probability of compliance with a defined level of over-collection. The following example can be used to illustrate this point.

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A mill is required to collect 11.1 lb MeOH/ODTP. The relative standard deviation of the methanol content of the named streams is 30%. The state and the mills have agreed that the permit would allow an averaging time which ensures 95% compliance probability at 10% over-collection.

For the example mill, 10% over-collection means collecting 12.21 lb MeOH/ODTP. The standard deviation at 12.21 lb MeOH/ODTP would be 3.66 lb MeOH/ODTP (12.21 x 30/100). Table 4 shows compliance probabilities for the mill for different averaging periods at this level of over-collection.

Based on calculations shown in Table 4 and the permit condition which would allow 95% compliance probability at 10% over-collection, the example mill would be granted a 29-day averaging period for compliance determination. The mill may decide to over-collect by more than 10% if it desires a higher probability of compliance.

Table 4 Impact of Averaging Period on Compliance Probability

Averaging Period, days	Standard Deviation, lb MeOH/ODTP	Compliance Probability, %
1	3.66	61.9
5	1.64	75.1
10	1.16	83.1
15	0.95	88.0
20	0.82	91.3
25	0.73	93.5
29	0.67	95.0

The approach outlined above offers several advantages. First, it offers a method for establishing the averaging time for different mills. Second, the approach takes into consideration the variability in methanol content and does not penalize mills with high variability. Third, it establishes a common basis for calculating the averaging time, using a pre-defined level of over-collection. Finally, mills which over-collect beyond the predefined level benefit from over-collection as their compliance probability would be higher than the preselected level, thus reducing the chances of non-compliance in any compliance test.

Procedure for Calculating Averaging Period Corresponding to 95% Compliance Probability at 10% Over-collection

If a mill collects H lb/ODTP of condensates with an average HAP concentration of C ppm and a standard deviation in HAP concentration, based on daily values, of S ppm, the average amount of methanol collected (Q) would be given by:

$$Q = H \times C \times 10^{-6} \quad \text{lb/ODTP} \qquad (1)$$

The standard deviation of HAPs in the condensates, when measured as lb/T, would be given by:

$$S_i = H \times S \times 10^{-6} \text{lb/ODTP} \qquad (2)$$

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If a mill collects Q lb/ODTP of HAPs at a standard deviation of S_i lb/ODTP, and the required HAP collection level is R lb/ODTP, the probability of compliance with the standard in a one-day test can be calculated from the Z table,

$$\text{where } Z = \frac{(Q - R)}{S_i} \tag{3}$$

at 10% over-collection, the amount of HAP collected (Q_{10}) would be equal to 1.1R, i.e.,

$$Q_{10} = 1.1R \tag{4}$$

Assuming that the concentration of HAPs in the collected stream does not change at 10% over-collection (the new stream is a subset of the original stream), the condensate stream methanol content at 10% over-collection (H_{10}) would be such that

$$Q_{10} = H_{10} \times C \times 10^{-6} \tag{5}$$

Substituting for Q_{10} from equation (4) gives

$$H_{10} \times C \times 10^{-6} = 1.1R$$

$$\text{or } H_{10} = \frac{1.1R}{(C \times 10^{-6})} \tag{6}$$

At this new flow rate, the standard deviation in the HAP content of the stream would still be S ppm but would change to a new value (S_{10}) when calculated as lb/ODTP based on the new flow rate H_{10}. The new standard deviation would be given by:

$$S_{10} = H_{10} \times S \times 10^{-6} \tag{7}$$

If the number of days in the averaging period is increased from 1 to d days, according to the Central Limit Theorem, the new standard deviation at 10% over-collection ($S_{10,\,d}$) would be given by the following:

$$S_{10,d} = \frac{S_{10}}{\sqrt{d}}$$

Substituting for S_{10} from (7) in the above equation gives

$$S_{10,d} = \frac{H_{10} \times S \times 10^{-6}}{\sqrt{d}} \tag{8}$$

At 10% over-collection and an averaging period of d days, from equation (3),

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$$Z_{10,d} = \frac{(Q_{10} - R)}{S_{10,d}} \tag{9}$$

Substituting for Q_{10} from (4) in equation (9) above gives

$$Z_{10,d} = \frac{(1.1R - R)}{S_{10,d}}$$

$$= \frac{0.1R}{S_{10,d}}$$

Substituting from (8) for $S_{10,\,d}$ in the above equation gives

$$Z_{10,d} = \frac{0.1R}{\dfrac{H_{10}\ x\,S\,x\,10^{-6}}{\sqrt{d}}}$$

$$= \frac{0.1R\sqrt{d}}{H_{10}\ x\,S\,x\,10^{-6}}$$

Substituting for H_{10} from (6) in the above equation gives

$$Z_{10,d} = \frac{0.1R\sqrt{d}}{\dfrac{1.1R\,x\,S\,x\,10^{-6}}{C\,x\,10^{-6}}}$$

$$= \frac{0.1\sqrt{d}}{1.1\dfrac{S}{C}} \tag{10}$$

Multiplying and dividing (10) by 100 gives

$$Z_{10,d} = \frac{0.1\sqrt{d}\,x\,100}{1.1\dfrac{S}{C}\,x\,100}$$

$$= \frac{10\sqrt{d}}{1.1\dfrac{S}{C}x100} \tag{11}$$

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However, $\frac{S}{C} x 100 =$ percent relative standard deviation (RSD) of the HAP concentration of the condensate stream. Thus, equation (11) above may be rewritten as

$$Z_{10,d} = \frac{10\sqrt{d}}{1.1\,RSD} \qquad (12)$$

At 95% compliance probability in a one-tailed test, Z = 1.645. One can use this value to calculate the number of days in the averaging period required to achieve 95% compliance probability from equation (12). Thus, equation (12) may be rewritten as

$$1.645 = \frac{10\sqrt{d}}{1.1 x\, RSD} \quad \text{, or}$$

$$\sqrt{d} = \frac{1.645 x 1.1 x\, RSD}{10} \quad \text{, or}$$

$$= 0.181 x\, RSD$$

$$d = (0.181 x\, RSD)^2 \text{, where} \qquad (13)$$

d = no. of days in the averaging period

RSD = percent relative standard deviation of daily methanol collection values in lb/ton

$$= \frac{(\text{standard deviation of methanol content of collected streams, lb/MeOH/ODTP})}{(\text{mean methanol collection, lb MeOH/ODTP})} x\, 100$$

For example, if the relative standard deviation of methanol content of the collected streams is 30%, according to equation (13), the mill would be allowed an averaging period of 30 days (29.5 days).

The above equation can, thus, be used to calculate the number of days required to achieve a compliance probability of 95% at 10% over-collection. This equation can be easily modified if the compliance probabilities or levels of over-collection are changed.

ED_000419-0004361

Attachment C

AF&PA Supplemental Comments on Proposed National Emission Standards for Hazardous Air Pollutants From the Pulp and Paper Industry (76 Fed. Reg. 81328, December 27, 2011), June 27, 2012.

American
Forest & Paper
Association

July 27, 2012

Ms. Gina McCarthy
Assistant Administrator for Air & Radiation
United States Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

RE: Docket ID No. EPA–HQ–OAR–2007-0544, National Emission Standards for Hazardous Air Pollutants From the Pulp and Paper Industry (76 Federal Register 81328, December 27, 2011)

Dear Assistant Administrator McCarthy,

The American Forest & Paper Association ("AF&PA") appreciates the opportunity to submit supplemental comments on the Proposed National Emission Standards for Hazardous Air Pollutants From the Pulp and Paper Industry (76 Fed. Reg. 81,328, December 27, 2011) (the "Proposed Rule"). These comments provide additional information in response to EPA statements and requests for comments in the preamble to the Proposed Rule concerning the provisions of the existing Pulp and Paper MACT standards, 40 C.F.R. Part 63 Subpart S, related to excess emission allowances for periods of venting of non-condensible gases (NCGs) and steam stripper downtime, and related provisions for equipment startup, shutdown, and malfunction. See 76 Fed. Reg. at 81,346.

These comments supplement comments AF&PA filed on the Proposed Rule on February 27, 2012 (the "AF&PA RTR Comments"). The Proposed Rule raised issues about the excess emission allowance provisions that had not been discussed with EPA during the development of the Proposed Rule and asked numerous questions about industry practices that called for the collection of additional information. In your February 22, 2012 letter to me, EPA agreed to consider information regarding excess emission allowances, including the results of a survey to be conducted by the National Council for Air and Stream Improvement, Inc. (NCASI) and "any other relevant information" received by June 27, 2012, in deciding how EPA should proceed with the excess emission allowance provisions.

These comments submit the results of that NCASI survey, which was developed with input from EPA's Office of Air Quality Planning and Standards, in the attached NCASI report, "The Collection and Transport of Noncondensible Gases (NCG) in

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NCG Systems at Pulp and Paper Mills." The NCASI Report also provides important explanatory information about the production process and pollution control operations at pulp mills that is critical for an understanding of why the existing Subpart S standards are written the way they are and of the implications of any changes EPA might make to those standards. The following discussion further explains some of the key implications of the NCASI Report and presents AF&PA's position on what actions EPA is authorized to and should take with respect to the Subpart S standards.

AF&PA believes that the information and arguments supplied here strongly support the conclusion that the excess emission allowances and related provisions of the current Subpart S regulations were consistent with the Clean Air Act and with the performance of best-performing mills representing the "MACT floor" when they were promulgated, and that they continue to be so today. We want to emphasize that the OAQPS staff, none of whom were involved in the development of the existing Subpart S regulations, have made a great effort to understand the complexity of chemical pulp mill operations and of the various compliance options the regulations currently provide and the reasons for those options. After your staff have considered the information submitted here, AF&PA is ready and willing to continue our dialogue and attempt to further EPA's understanding of the regulated facilities.

Background

The National Emission Standards for Hazardous Air Pollutants for the Pulp and Paper Industry, 40 C.F.R. Part 63 Subpart S, require that various processes in the pulp mill be enclosed and vented into a closed-vent system and routed to a control device. The regulations provide that periods of excess emissions must be reported but will not be considered a violation if, for each semi-annual reporting period, the time of excess emissions (excluding periods of startup, shutdown, or malfunction) divided by the total process operating time does not exceed 1% for control devices used to reduce emissions from the low volume, high concentration system and 4% for control devices used to reduce emissions from the high volume, low concentration system (or used for both LVHC and HVLC systems). 40 C.F.R. § 63.443(e). For control devices used to treat pulping process condensates (wastewaters) from specified pulp mill processes, the excess emission allowance (including periods of startup, shutdown, or malfunction) is 10%. 40 C.F.R. § 63.446(g). In addition to continuous monitoring of the control devices, the regulations require indicators on closed-vent system bypass lines, periodic inspections for leaks, procedures for prompt repair of defects in the enclosures or piping, inspection and maintenance recordkeeping, and so forth.

As explained in the AF&PA RTR Comments, the excess emission allowance provisions in the current Subpart S regulations reflect EPA's careful determination, after years of study of a large quantity of emissions information and public

comments, that the "MACT floor," representing the emissions of the "best performers," includes emissions during unavoidable periods of releases of uncontrolled or partially controlled pulping process vent gases and unavoidable sewering of untreated or partially treated pulping process condensates. See 63 Fed. Reg. 18,504, 18,529 (April 15, 1998). "EPA established appropriate excess emission allowances to approximate the level of backup control that exists at the best-performing mills and the associated period of time during which no control device is available." *Id.* After "an analysis of the public comments and the available data regarding excess emissions and the level of backup control in the industry," EPA determined that the "best-performing mills achieve a one percent downtime in their LVHC system control devices" and "best-performing mills achieve a four percent downtime in the control devices used to reduce emissions from their HVLC system to account for flow balancing problems and unpredictable pressure changes inherent in HVLC control systems." *Id.* "The allowances address normal operating variations in the LVHC and HVLC system control devices for which the equipment is designed. The variations would not be considered startup, shutdown, or malfunction under the Part 63 General Provisions…." 63 Fed. Reg. at 18,530 (emphasis added). The 10 percent excess emission allowance for steam strippers systems "accounts for stripper tray damage or plugging, efficiency losses in the stripper due to contamination of condensate with fiber or black liquor, steam supply downtime, and combustion control device downtime." *Id.*

EPA adopted the excess emission allowances after reviewing extensive data from continuous monitoring systems and considering industry comments that although some mills had backup combustion devices as part of their LVHC control system, venting of pulping gases is an essential safety practice (because of their explosion hazard) even for those systems with backup control devices, since the startup of, and transfer of vent gases to, the backup controls cannot be immediate or automatic for safety reasons, and operating variability in the control devices themselves was unavoidable for process and other reasons. See, e.g., Pulp, Paper and Paperboard Industry – Background Information for Promulgated Air Emission Standards – Final EIS, EPA-453/R-93-050b (October 1997) ("BID") at 4-81, 4-82 to 4-84. For HVLC systems, few mills had backup controls that could handle the large volume of vent gases, so any standard that required the use of backup devices would have been beyond the MACT floor and would not have been cost-effective due to the low concentration of pollutants in the large gas stream. See 63 Fed. Reg. at 18,529; BID at 4-81 to 4-82. See also BID at p. 1-41 ("EPA established excess emission allowances to approximate the level of downtime and number of backup control devices that exist at the best-performing mills. The Excess emissions allowances are designed to account for periods when the control device is inoperable and when the operating parameter values established during the initial performance test cannot be maintained due to problems with the process.").

In short, the MACT determinations that EPA made when promulgating the Subpart S emission standards correctly concluded that available technology involves unavoidable periods where not all vent gases or condensates can be routed to the control device, and/or when the control device is inoperable or necessarily operating at a reduced rate. The Subpart S emission standards (including the excess emission allowances) were designed to reflect the performance of the MACT technology and the actual performance of the "best performing" mills. Without the excess emission allowances, the remainder of the Subpart S emissions standards would have imposed limitations not achieved even by the "best performers" and not demonstrated as achievable at any facility. The NCASI Report submitted with these comments reinforces those conclusions.

The Proposed Rule

In the December 27, 2011 Proposed Rule, EPA proposed a significant change to the excess emission allowance provisions of the Subpart S standards: EPA proposed to remove the parenthetical clause in 40 C.F.R. § 63.443(e), "(excluding periods of startup, shutdown, or malfunction)." The effect of this proposed change would be to make the excess emission allowance provisions of the Subpart S standards for NCG systems significantly more stringent, because not only would normal operating variations in the LVHC and HVLC system leading to excess emissions have to fall below 1 percent or 4 percent, respectively, of the operating hours, but in addition periods of startup, shutdown, and malfunction (which were not intended to be addressed by the excess emission allowance provisions, see 63 Fed. Reg. at 18,530, quoted above) would have to be less than those percentages, as well.

EPA stated, in the preamble to the Proposed Rule: "In proposing the standards in this rule, the EPA has taken into account startup and shutdown periods and is not proposing a different standard for those periods. Nothing in the record suggests that the operations (and attendant emissions) are significantly different during startup or shutdown than during normal operation. Periods of startup, normal operations and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment or a process to operate in a normal or usual manner * * *" (40 CFR 63.2). The EPA has determined that CAA section 112 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 112 standards." 77 Fed. Reg. at 81,346.

In addition, in the preamble to the Proposed Rule EPA indicated that it was considering changing or removing the excess emission allowance provisions of the Subpart S rule more generally: "We request comment on whether these provisions should be removed or modified in the final rule, as the provisions create time periods during which a source does not have to comply with a CAA section 112-compliant

standard, which we believe is arguably at odds with [*Sierra Club v. EPA, 551 F.3d 1019 (D.C. Cir. 2008), cert. denied, 130 S. Ct. 1735 (2010)*]." 76 Fed. Reg. at 81,346. EPA explained that the excess emission provisions for LVHC, HVLC, and steam stripper systems were intended to reflect the performance of best-performing mills [and therefore reflective of the "MACT floor"], but EPA did not offer any explanation of how it could remove those excess emission provisions without violating Clean Air Act requirements that EPA must either base MACT standards on the performance of the best-performing mills or justify beyond-the-floor standards. See *id.* EPA sought considerable information about how the excess emission allowances in the existing Subpart S. standards are used, how facilities distinguish between routine venting and malfunctions, etc. *Id.* These comments and the attached NCASI Report attempt to respond to those questions. See NCASI Report – discussion in item # 3, p.23.

<u>EPA Lacks Authority To Change the Excess Allowance Provisions</u>

As a threshold matter, AF&PA wishes to reiterate its position, expressed in the AF&PA RTR Comments, that the Clean Air Act does not authorize EPA to revise the excess emission allowance provisions, either by eliminating those provisions or adding additional conditions to them, as EPA has indicated it is contemplating, or by removing the exclusion for SSM periods and thereby forcing mills to use the 1% and 4% venting allowances for SSM periods as well as for routine operating events that trigger intermittent NCG venting, as EPA has proposed.

The Proposed Rule generally reflects EPA's efforts to consider whether additional emission limitations are necessary to address residual risk, under CAA section 112(f), and whether changes to the MACT standards are "necessary" in light of "developments in practices, processes, and control technologies," under CAA section 112(d)(6). EPA has determined that the minimal residual risk after implementation of the MACT standards does not justify additional requirements under section 112(f). With respect to the technology review under section 112(d)(6), nothing has changed about the technology available to control volatile HAP emissions at pulp mills that eliminates the unavoidable excess emission the events that EPA accurately described and addressed when promulgating the current MACT standards—a fact confirmed by the NCASI Report. Absent such new technology, there is no statutory predicate for EPA to go back and change the MACT standards at this time. *Cf. NRDC v. EPA*, 529 F.3d 1077, 1084 (D.C. Cir. 2008) (rejecting contention that CAA section 112(d)(6) requires EPA to "start from scratch" and develop new MACT standards). To the contrary, Congress (1) did not provide for periodic review and revision of MACT standards (other than the 8-year technology review under CAA section 112(d)(6)), as it has for many other types of standards under the Clean Air Act and other environmental statutes, and (2) made the MACT

standards subject to a strict 60-day deadline for seeking judicial review, under CAA section 307(b), so that sources would have certainty about what standards they face.

Note that, even if the Clean Air Act allowed EPA to second-guess and revise the existing MACT standards, EPA has no technical basis for eliminating the Subpart S excess emission allowances. An agency cannot simply change its mind and reach a diametrically opposed conclusion from the determination it made in a prior rulemaking. Rather, EPA must demonstrate sufficient basis for changing its prior conclusions; in this case, technical justification for concluding that mills with MACT do not experience the unavoidable variability accommodated by the excess emission allowance. See, e.g., *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502 (2009) ("a reasoned explanation is needed for disregarding facts and circumstances that underlay…the prior policy"); *Transactive Corp. v. United States*, 91 F.3d 232, 237 (D.C. Cir. 1996).

In the case of standards under CAA section 112(d), EPA not only would have to have a substantial technical basis for reversing its conclusions reflected in the current Subpart S standards, it also would have to demonstrate that the revised standards would reflect the MACT "floor" or are justified as "beyond-be-floor" requirements. As AF&PA's RTR Comments showed, EPA has not made any effort to show that the elimination of the SSM portion of the NCG venting allowances in 40 C.F.R. § 63.443(e) would be consistent with the performance of the best-performing mills that characterized the MACT floor when the Subpart S standards were promulgated (or the current best-performers, for that matter). Nor has EPA assessed elimination of the SSM provision as a beyond-the-floor technology.

The same would be true of eliminating or narrowing the excess emission allowances for NCG systems and steam strippers. Before EPA could propose such a change to the Subpart S. standards, EPA would have to show how emission limitations that did not include those excess emission allowances reflect the MACT floor (despite EPA's conclusion in 1998 to the contrary) or are justified as a beyond-the-floor requirement.

<u>The Excess Emission Allowances Have a Firm Basis in Fact and Law</u>

In the preamble to the Proposed Rule, EPA stated that the existing Subpart S excess emission "provisions create time periods during which a source does not have to comply with a CAA section 112-compliant standard, which we believe is arguably at odds with *Sierra Club*." 76 Fed. Reg. at 81,346. That is simply wrong, on several levels.

First, the *Sierra Club* decision interpreted the NESHAPs General Provisions, not the Subpart S NESHAPs or indeed any categorical NESHAPs. Secondly, the decision addressed an exemption for startups, shutdowns, and malfunctions, while the

Subpart S excess emission provisions for pulping vent gases specifically does not address excess emissions during startup, shutdown, and malfunction (see 40 C.F.R. § 63.443(e)).

Thirdly, the *Sierra Club* decision rejected the General Provisions' blanket, open-ended exemption for emissions during startup, shutdown, and malfunction periods, finding it to be inconsistent with Congress's intention that "there must be continuous section 112-compliant standards" for sources subject to MACT standards, rather than periods where no standard of any kind applies. See 551 F.3d at 1027. The problem with the General Provisions SSM exemption, in the Court's eyes, was that it allowed sources to be exempt from any standard at all, and that it was not derived (by EPA's admission) applying the factors in CAA section 112(d) or 112(h). See *id.* at 1027-28, 1030. The *Sierra Club* opinion did not address a situation, such as the Subpart S standards, where EPA finds that the MACT standard, which applies continuously, must account for periods of higher emissions during unavoidable operational variability to accurately reflect the available technology and the best performers' emissions. In fact, the *Sierra Club* decision explicitly acknowledged that it may be appropriate for MACT standards to have different limitations for different situations. See 551 F.3d at 1021; *id.* at 1027 (standard may "'assure continuous emission reduction' without necessarily continuously applying a single standard").

The excess emission allowances in the existing Subpart S rule are no different conceptually than other emission standards EPA has established for scores of sources that are expressed as an average calculated over a day, a month, or longer.[1] MACT standards that require a source to meet a particular emission rate measured as, e.g., a 30-day average do not require that the source emit at any specific rate during each hour of operation, so long as the 30-day average is below the limit. EPA effectively recognized this in the preamble to the Proposed Rule, asking whether the events currently covered by the excess emissions allowances in the Subpart S rule can be addressed through an emission standard with a longer averaging time. See 76 Fed. Reg. at 81,346. Such emission limitations expressed as averages, about which there can be no reasonable question as to their validity under CAA section 112, are no more (or less) compliant with the D.C. Circuit's

[1] Many MACT standards, including "all past part 63 NESHAPs affecting the chemical and refining sectors," use daily averaging periods (see 77 Fed. Reg. 17,898, 17,963 (March 26, 2012), and it is not uncommon for MACT standards to allow averaging over a month or a year. See, e.g., 40 C.F.R. §§ 63.491(c), 63.3522 (MACT standards for Surface Coating of Metal Cans requires demonstration of compliance with limit on HAP content of coatings, or emission rate if using control equipment, as a rolling 12-month average determined on a monthly basis); 40 C.F.R. § 63.2840 (MACT standards for Vegetable Oil Production require facilities to meet limit on gallons of HAP lost per ton of oilseeds processed, expressed as ratio of actual gallons lost during previous 12 months to allowable); 68 Fed. Reg. 19375, 19378 (Apr. 21, 2003) (Reinforced Plastic Composites Production) (compliance based on weighted HAP emission factor based on a 12-month rolling average calculated monthly).

interpretation that MACT standards must meet a section 112-compliant standard at all times than are the Subpart S standards, which require that, e.g., LVHC systems stay within the specified limits at least 99% of the time for each six-month period.[2]

To put it another way, If one assumes that six months equals 180 days or 4320 hours, the 1% excess emission allowance the existing Subpart S standards provide for LVHC systems means that a mill would be allowed, at most, to exceed the emission limitations for LVHC systems a little over 43 hours in a six-month period. Even if the mill's LVHC NCG emissions were not controlled at all during those 43 hours, and even if the mill's LVHC system were emitting just at the Subpart S emission limitation of 98% volatile HAP reduction for the remaining 4277 hours, that would still be equivalent to an average 97% reduction of volatile HAPs during the six-month period. Since EPA has issued many MACT standards that allow averaging over a day, a month, or more, EPA has no basis for claiming there is something inconsistent with the Clean Air Act about the excess emissions allowances in the Subpart S standards, which are functionally equivalent to, e.g., a 97% reduction standard for LVHC gases, expressed as a six-month average.[3] In fact, EPA has specifically used averaging times to accommodate process variability, as it did with the excess emission allowances in the Subpart S rule, in other MACT rulemakings.[4]

Without the excess emission provisions, the Subpart S standards would not comply with CAA section 112. Section 112(d) standards based upon the performance of the best-performing facilities are supposed to represent "the emissions control that is achieved in practice" by the best performers, which means that the best-performing mills would not violate the standards, which "only results if 'achieved in practice' is

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[2] EPA has promulgated numerous other MACT standards that are even more directly comparable to the excess emission allowances in Subpart S, in that they allow a source to exceed the numerical limit with a certain frequency. See, e.g., NESHAPs for Catalytic Cracking Units at Petroleum Refineries, 40 C.F. R. pt. 63 subpt. UUU Table 6 (sources subject to NSPS must "maintain[] each 6-minute average [opacity] at or below 30 percent except that one 6-minute average during a 1-hour period can exceed 30 percent")—effectively a 10% excess emission allowance.

[3] EPA also has issued many New Source Performance Standards under CAA § 111 that are expressed in terms of long averaging times, and which rely on the same definition of "emission limitation" that the *Sierra Club* court relied on in striking down the NESHAP General Provisions. See, e.g., 40 C.F.R. § 60.72a (emission limit for Nitric Acid Plants expressed "as a 30-day emission rate calculated based on 30 consecutive operating days") 77 Fed. Reg. ___ (signed May 14, 2012).

[4] See, e.g., 66 Fed. Reg. 44217, 44225 (Aug. 22, 2001) (Boat Manufacturing) ("one of our objectives was to provide flexibility to use some higher HAP materials by adopting the averaging provisions and using weighted-average HAP contents in setting the MACT for each operation."); 65 Fed. Reg. 15,690, 15,699 (March 23, 2000) (Secondary Aluminum) (3-day, 24-hour rolling average selected to accommodate variations in cycle times and schedules).

interpreted to mean 'achieved under the worst foreseeable circumstances.'" *Sierra Club v. EPA*, 167 F.3d 658, 665 (D.C. Cir. 1999). The courts (and EPA) have recognized that there is variability in the performance of control technologies, which needs to be accounted for in establishing emission limitations based on the MACT floor. See, e.g., *Cement Kiln Recycling Coalition v. EPA*, 255 F.3d 855, 862-865 (D.C.Cir.2001). As the record (including, now, the NCASI Report) reflects, it is certainly foreseeable that even the best performers would experience violations of the MACT standards, due to process variability and control technology limitations, without an excess emission allowance.

It should be emphasized that the excess emission allowances in the current Subpart S standards do not result in periods where emissions from NCG and condensate streams are subject to no restrictions at all. Obviously, a mill could only tolerate a small amount of equipment downtime or unavoidable venting and still stay under the percentage allowances. The Subpart S regulations contain numerous obligations that continue to apply irrespective of the excess emission allowances, e.g., indicators on closed-vent system bypass lines, periodic inspections for leaks, procedures for prompt repair of defects in the enclosures or piping, inspection and maintenance recordkeeping, and so forth. In addition, the mill's operation remains subject to the "general duty" in 40 C.F.R. § 63.6(e) to operate and maintain the affected sources, and associated air pollution control and monitoring equipment, consistent with safety and good air pollution control practices for minimizing emissions. Similar requirements apply under the laws and regulations of many states, and the mill may also be subject to state emission limitations, or limitations under NSPS or other applicable regulations, that restrict emissions from the mill. (See, e.g., reference to the State of Maine's TRS control regulations in the NCASI Report at p.30) Moreover, since the NCG and condensate systems have the potential for causing releases of objectionable odor to the community, as well as potentially harmful worker exposures, kraft pulp mills must continually strive for reducing emissions from those streams. The potential for triggering releases of reportable quantities under the Emergency Planning and Community Right-to-Know Act provides yet another restraint on venting. The venting events described in the NCASI Report therefore represent the minimal emissions that are unavoidable using best practices, and subject to the restraints not only of the Subpart S standards but also numerous other requirements or incentives for the mills to minimize emissions.

Finally, even if the current Subpart S standards were inconsistent with the *Sierra Club* decision, which the discussion above shows they clearly are not, that fact alone would not allow EPA to change the excess emission allowance provisions in the Subpart S rule. The Subpart S NESHAPs were never judicially challenged, and the time for such a challenge under CAA section 307(b) has long passed. Even if the rationale that the D.C. Circuit used in overturning a different regulation in one of the many cases challenging other NESHAPs is arguably inconsistent with the approach EPA took in promulgating the Subpart S NESHAPs, that would not provide a means

or a justification for reopening the Subpart S standards that were never challenged on that grounds. See *id.* and, e.g., *Sierra Club v. EPA*, 353 F. 3d at 986 (MACT standards must be judged on the adequacy of EPA's explanation in the particular rulemaking, not on what EPA did based on a different record in a different rulemaking).

In short, the excess emission allowance provisions of the existing Subpart S standards not only are permissible under the Clean Air Act, they are necessary. The MACT floor performance includes unavoidable periods when mill operations preclude compliance with the limitations EPA established for steady-state operations, and so to reflect that performance the MACT standards need to accommodate those periods. EPA already has assessed—as past court decisions, including even the recent Sierra Club decision, have indicated it must—whether different emission limitations need to apply to those periods of operational variability and has addressed that need through the excess emission allowances in existing sections 63.443(e) and 63.446(g). No further EPA action is necessary.

The Excess Emission Allowances Are *Not* Unauthorized Exemptions for Malfunctions

In recent discussions with EPA OAQPS staff, EPA's default position seems to be that, with the possible exception of startup and shutdown periods, any venting of NCGs or sewering of condensates under the excess emission allowance provisions of the existing Subpart S standards is the result of a "malfunction," and therefore cannot be allowed by MACT standards. This is wrong on several levels. First, it is directly contrary to EPA's analysis of the facts in support of the current MACT standards, in which EPA stated: "The allowances address normal operating variations in the LVHC and HVLC system control devices for which the equipment is designed. The variations would not be considered startup, shutdown, or malfunction under the Part 63 General Provisions…." 63 Fed. Reg. at 18,530. From everything AF&PA is aware of, EPA's current, diametrically opposite conclusion is not based on any new analysis of data, making it necessarily arbitrary and capricious.

Secondly, both AF&PA's RTR Comments and the NCASI Report submitted with these comments explain, with real-world examples, why the excess emission allowances are necessary to reflect actual performance of even the best-performing mills, because of unavoidable fluctuations in the production processes and the NCG and condensate collection and treatment systems. See AF&PA RTR Comments at pp.53 - 57; NCASI Report at pp.15 - 20. EPA has not presented, and could not present, any factual basis to the contrary.

An easy-to-understand example is availability of a thermal destruction device used to comply with the emission standards for NCGs (and for off-gases from steam strippers used to treat condensates). In the original Subpart S rulemaking, EPA

recognized that most mills did not have backup equipment for incinerating HVLC gas streams, and even if backup equipment was available for treating LVHC gas streams, there would be a period of uncontrolled emissions when switching to a backup thermal destruction device. The primary thermal destruction device might be unavailable for a number of reasons that have nothing to do with malfunctions, such as routine maintenance, the temporary loss of NCG burning permissives even though the device itself is operational, or, if a piece of process equipment is used as the primary thermal destruction device, because the associated process is not operating or is starting up or shutting down. Similarly, a steam stripper will, over time, have to be taken offline because of the temporary unavailability of the thermal destruction device, as described above, or to remediate ordinary clogging of the stripper trays (during which time the condensates typically are routed to the mill's wastewater treatment system, see NCASI Report at p.29). Even the best-performing mills do not have redundant stream strippers to avoid these periods when the stripper has to be offline.

These periods are not periods of malfunction, as defined in 40 C.F.R. § 63.2, because they are not "infrequent," they do not represent a "failure" of equipment "to operate in a normal or usual manner," and they are not "reasonably preventable." As recently as this March, EPA has reiterated that it is appropriate, in comparable situations, to establish alternative MACT standards, rather than claiming, as the preamble to the Proposed Rule implied, that such situations cannot be accommodated by MACT standards and must not only be considered malfunctions but also be treated as violations.[5] The NCASI Report presents numerous examples, in addition to and further explaining the examples in the AF&PA RTR Comments, about why the NCG or condensate collection and treatment systems at a pulp mill may not be able to meet the Subpart S emission limits and performance standards due to routine events that are part of expected process and pollution control variability and for which the system is designed. See, e.g., NCASI Report at pp. 15 - 20.

EPA's position in the original Subpart S rulemaking that the excess emission allowances are necessary "to address normal operating variations in the LVHC and HVLC system control devices for which the equipment is designed" and would not be considered malfunctions, 63 Fed. Reg. at 18,530, is consistent as well with

[5] See 77 Fed. Reg. at 17,923 ("As in current rules, we are proposing to require different standards for periods of planned routine maintenance of the control device. We are not proposing to require compliance with the same standard at all times because the cost of such a requirement would be unreasonable. Instead, we are proposing to prohibit the addition of material to the storage vessel during periods of planned routine maintenance and to limit the time of planned routine maintenance to less than 360 hr/yr. If you need more than 240 hr/yr, you would be required to keep a record documenting why 240 hours is insufficient and the steps you took to minimize the additional time for planned routine maintenance.")

information the industry provided in comments on the proposed Subpart S. regulations. AF&PA's comments stated that the definition of "malfunction" and the malfunction exemption in the NESHAPS General Provisions would not cover the excess emissions for which an allowance was sought for "the process venting we have described since these episodes are not generally considered by the industry or regulatory officials to be malfunctions, in the sense that that term conveys technical limitations of pollution control equipment. These are truly situations of process variability. Thus, the agency must provide for excess emissions venting during these minimal periods of process equipment downtime." AF&PA Comments, April 18, 1994, at MACT-64. Nothing has changed, and in fact the information in the NCASI Report provides further support for this conclusion. NCASI Report at pp. 15 – 20. EPA has no factual basis for concluding otherwise.

Note that EPA has recognized similar situations, where a facility experiences non-standard operating conditions which are not malfunctions. For example, in proposed National Uniform Emission Standards for Storage Vessel and Transfer Operations, Equipment Leaks, and Closed Vent Systems and Control Devices, March 26, 2012, 77 Fed. Reg. 17,898, proposed 40 C.F.R. § 65.925 recognizes that "nonstandard batches" can occur in chemical processing that do not represent "malfunctions":

> Nonstandard batch means a batch process that is operated outside of the range of operating conditions that are documented in an existing operating scenario, but is still a reasonably anticipated event. For example, a nonstandard batch occurs when additional processing or processing at different operating conditions must be conducted to produce a product that is normally produced under the conditions described by the standard batch. A nonstandard batch may be necessary, as a result of a malfunction, but it is not itself a malfunction.

77 Fed. Reg. at 17,984.

Finally, even if none of the facts presented in AF&PA's 1994 comments, the AF&PA RTR Comments, and the NCASI Report existed, and EPA instead had some basis for asserting that all of the (non-startup or -shutdown) events covered by the excess emission allowances in the existing Subpart S rule are malfunctions, that alone still would not justify deleting the excess emission allowance provisions from the rule. Despite EPA's implication, nothing in the 2008 *Sierra Club* decision said that malfunctions cannot be considered when setting emission standards. Nor did the decision say that MACT standards cannot accommodate malfunctions, through a separate numerical standard under CAA section 112(d) or through a design, equipment, work practice or operational standard under CAA section 112(h).[6] To

[6] As AF&PA's RTR Comments noted, in the Proposed Rule EPA did not even consider the latter, which made EPA's proposed decision to treat all malfunctions as *per se* violations arbitrary and capricious.

the contrary, the *Sierra Club* decision acknowledged the possibility of having more than one MACT standard that would apply to different circumstances and of having design, equipment, work practice, or operational standards that applied in lieu of limitations on the amount or concentration of pollutants emitted. See 551 F.3d at 1021, 1027-28.

The Excess Emission Allowances Are Necessary To Address Periods of Startup and Shutdown

The current Subpart S emission standards contain an exemption for excess emissions of NCGs related to startup and shutdown (and malfunction). EPA determined that this exemption was necessary in addition to the excess emission allowance in 40 C.F.R. § 63.443(e). Excess emissions during startup and shutdown are not exempted from the pulping condensate steam stripping requirement, but only because EPA did not have data to distinguish those situations from "normal stripper operating emissions." See 72 Fed. Reg. at 18,529-30. In the preamble to the Proposed Rule, however, EPA stated, without explanation, that it had "taken into account startup and shutdown periods and is not proposing a different standard for those periods. Nothing in the record suggests that the operations (and attendant emissions) are significantly different during startup or shutdown than during normal operation." 76 Fed. Reg. at 81,346. This appears to be just an arbitrary, unsupported rejection of EPA's prior factual determinations.

In any event, it is inaccurate. Supplementing information in the docket for the original Subpart S rulemaking, the NCASI Report documents that startup and shutdown conditions at pulp mills are unlike normal operations and create distinct situations in NCG and condensate collection and treatment systems that result in intermittent venting episodes. NCASI Report at pp. 21 - 23. Additionally, startup or shutdown of a production process can result in unusual variability in the NCG or condensate system, resulting in higher emissions during startup or shutdown conditions, including intermittent venting, than occur during steady-state operations. *Id.*

EPA has repeatedly acknowledged that it has authority under CAA section 112 to promulgate different emission limitations for startup and shutdown periods than for steady-state operations. See, e.g., 75 Fed. Reg. 54,970, 54991-92 (Sept. 9, 2010) (Portland Cement); 76 Fed. Reg.72,220, 72,794 (Nov. 25, 2011) (proposed alternative limits for startup and shutdown in the Mineral Wool and Wool Fiberglass Manufacturing source category) So the Agency's position for the Pulp and Paper Proposed Rule has to be not that it is precluded from establishing separate emission standards for startup and shutdown, but only that there is no need for such standards to accurately reflect the performance of the best performers. As explained above, the facts do not support that conclusion.

Since EPA is permitted to establish separate emission standards for startups and shutdowns, unless the Agency has a clear justification for departing from its decisions in the original Subpart S rulemaking, EPA should not disturb the provisions of the existing rules that address emissions during startup and shutdown. If EPA ignores the admonitions above about revising MACT standards and wishes to revise the standards that apply during startup and shutdown, EPA should develop, and propose for public comment, standards that reflect the criteria in CAA section 112(d) or in section 112(h). If EPA retains the excess emission allowances currently in the Subpart S regulations, it may be possible to fold startup and shutdown periods (as well as malfunctions) into the excess emission allowances for NCG systems, as EPA already did for steam strippers.

The NCASI Report Shows the Subpart S Excess Emission Allowances Are Justified

The NCASI NCG survey was conducted in order to answer specific questions raised by the EPA, in the December 27, 2011 proposal, on intermittent NCG venting that occurs during routine operations and is covered under the venting allowances in the existing Subpart S regulations. The NCASI report also provides a summary of the main characteristics NCG systems. While it is true that each individual NCG system is unique in the types of sources it collects, its configuration, and its accommodation of site-specific constraints, the same basic principles apply in designing and operating these systems. With this heterogeneity and complexity in mind, facilities were requested to provide qualitative information, based on prevailing process knowledge and experience, on the types of events triggering these intermittent venting episodes. Additionally, facilities were also requested to identify operating conditions or threshold operating parameters used to differentiate SSM venting events from those occurring during routine operation. ***A total of 81 kraft mills responded to the survey***. The NCASI report, provided as item #1 in the Appendix, analyzes the survey responses and draws collective conclusions on the types of events triggering intermittent venting.

Survey responses indicate that routine venting events can largely be attributed to process variability. As facilities have gained more experience in operating NCG systems, they have progressed along the learning curve in managing some of this process variability. However, it is impossible to eliminate all sources of process variability – hence the term inherent. Inherent process variability is an expected facet of day-to-day continuous operations, cannot be mitigated through better equipment design, and is inevitable. In fact, system designers expect this inherent variability – this is the reason why they design “fail-safe” / “fail-open” control systems to alarm and subsequently vent when the potential for unsafe conditions exist within these systems. This is the same reason why insurance companies and

technical committees like the Black Liquor Recovery Boiler Advisory Committee provide comprehensive recommendations on how best to design and operate these systems.

The primary objective of the NCG control system and associated interlocks is to (a) prevent NCGs from approaching flammability limits, (b) minimize the potential for unsafe conditions in the transport system and at the thermal destruction device, and (c) maintain safety and system integrity and prevent explosions. The network of alarms designed into NCG systems serves to provide operating boundaries for facilities and greatly minimizes venting episodes. These alarms also facilitate the secondary, but equally important, objective of minimizing the release of TRS compounds that cause objectionable odor in the community. In spite of tight control and operation, circumstances do arise that result in the tripping of vent thresholds. Given the primary objective of promoting safety and preventing explosions, facilities have no option but to mitigate these conditions using "fail-safe" strategies, viz., through intermittent venting.

Key takeaways from the NCASI survey are summarized below. More details and data are provided in the attached report.

1. ***Intermittent venting episodes can occur during routine or normal operation.*** These events are triggered by the expected inherent process variability and by transient conditions in the collection, transport, and conditioning equipment. This results in the tripping of safety and system integrity interlocks. These venting episodes and the events that trigger them are not malfunctions of associated equipment, because the systems continue to operate as designed and within expected ranges. These venting episodes are critical to maintaining system integrity and preventing catastrophic scenarios that could result in unsafe conditions for workers, equipment damage, and explosions.

   Inherent process variability is an expected component of day-to-day manufacturing processes. System designers expect this variability and design control/interlock systems to ensure safe operation in spite of this variability. If this variability were unexpected and uncharacteristic of these systems, there would be no need to design and implement "fail-open" control strategies.

2. ***Intermittent venting can also be caused by Startup and Shutdown (SS) events.*** In the context of the NCG system, Startup and Shutdown (SS) conditions are distinct and therefore unlike routine operations.

   - A subset of SS conditions trigger distinct interlocks and permissives within the NCG transport system or sub-systems, thus resulting in intermittent venting episodes.
   - Some of the intermittent venting during SS conditions can also be attributed to increased levels of process variability not expected or observed during routine operation.

   NCASI survey responses indicate that SS conditions trigger distinct scenarios within the process and within the NCG system. In other words, SS conditions are distinctly different from conditions that prevail during routine operation. Additionally, SS conditions result in unusually high levels of variability within the system, at levels that are not typically observed during normal operation. These high levels of variability during SS conditions cannot be avoided. It is therefore inappropriate to consider SS conditions to be similar to normal operation. EPA's premise in removing the SSM exclusions, specifically SS exclusions for NCG venting, was that "….nothing in the record suggests that the operations (and attendant emissions) are significantly different during startup or shutdown than during normal operation." 76 Fed. Reg. at 81,346. As discussed earlier, the survey results speak to the contrary, as it pertains to unit operations in pulp and paper mills and, specifically, NCG systems. NCASI survey responses indicate that SS conditions are indeed distinct as it pertains to the NCG collection and transport system and can trigger distinct operating conditions, non-steady-state operations, and interlock exceedances. Likewise, SS conditions affect steam stripper operations and justify the excess emission allowance covering steam stripper SS periods that is in the current Subpart S regulations.

3. ***The majority of mills use threshold parameters to differentiate routine operating periods from startup and shutdown (SS) periods. Others have defined specific actions that are required to be carried out in order to startup or shutdown a piece of equipment or process, thus differentiating the two.***

   NCASI survey responses indicate that facilities utilize varying approaches to distinguish SS periods from routine operation. While some

facilities use threshold parameters, others make the distinction by assessing the completion of a pre-defined set of tasks before the process can be termed "normal and ongoing" as opposed to under "SS." Given the fact that SS conditions are distinct, clearly differentiated, and trigger distinct conditions within the NCG system, AF&PA contends that EPA needs to preserve the venting allowances for these periods. Eliminating the SS venting allowances would seriously jeopardize safety and system integrity. It would effectively undo a decade worth of hard work and learning that the industry has developed and implemented, in the design and safe operation of these systems.

4. ***Survey results indicate that problems related to transport system equipment (gas conditioning equipment, sensors, and fiber/liquor separation equipment) are as prevalent as malfunctions related to process equipment and thermal destruction devices.*** Given the ability to isolate sub-systems, the former are less disruptive to overall NCG system operation than the latter. Transport system equipment problems also can be triggered by inherent process variability. Adequate consideration of the triggering events is therefore justified, before classifying all these as malfunctions as defined by the rule.

   NCASI survey results indicate that equipment malfunctions can fall into broadly variant categories. Those related to sensors, NCG conditioning and monitoring equipment etc., are distinctly different from those related to process equipment and control devices. The former are less disruptive, given the ability to isolate sub-systems and continue to operate the remainder of the system normally.

   Additionally, some problems with NCG sensing and conditioning equipment are the direct result of process variability (like foam and fiber carryover, steam supply variability, etc.) and cannot be considered as events that are "sudden, infrequent, and not reasonably preventable." First, given that inherent process variability is not reasonably preventable, these events also would not be reasonably preventable. More importantly, these events also have the potential to recur given that they are directly caused by process variability, i.e. it would be impossible to assure that these events are infrequent. It is therefore inappropriate (and too simplistic) to group all these problems with transport system equipment into a single category.

   AF&PA recommends that EPA draw additional distinctions when categorizing malfunctions and its applicability of affirmative defense provisions. Events related to transport system and conditioning system

equipment that are attributed to process variability should not be categorized as malfunctions as defined in the rule.

5. ***Steam stripper downtimes do not reflect "no HAP control" scenarios.*** Facilities routinely route their condensates to biological wastewater treatment systems during steam stripper downtime periods and thereby continue to achieve high levels of treatment for methanol and major non-methanol HAPs.

6. ***A handful of states impose limits on the duration of individual LVHC system vents.*** An example is the 40 minute limit imposed by the state of Maine.[7] Individual LVHC system vents in Arkansas, Oregon, and Alabama are limited to 30, 60, and 240 minutes, respectively.

Other pertinent takeaways relating to specific technical and operational aspects of NCG systems are as follows:

7. ***Intermittent venting is a consequence of "Fail-safe" systems, interlocks, and system permissives.*** These interlocks and the resulting intermittent venting are an essential "first line of defense" against system failures and potential hazardous conditions, including catastrophic explosions. Some are attributed to inherent process variability, others to SS conditions, and a third category can be the result of malfunctions.

8. ***Interlocks and permissives are essential components of any NCG system.*** These protections are designed into systems in order to prevent equipment damage, injuries, and potential fatalities. These are integrated into system design and considered as "prerequisites of insurability" by insurance companies. As discussed earlier, the BLRBAC recommendations and Factory Mutual Guidelines on the design and operation of NCG systems, both illustrate the importance of these permissives. Their suggested guidelines are widely followed in designing these systems and in carrying out insurance audits.

9. ***Intermittent venting episodes that occur during normal operation frequently resolve themselves or can be resolved through effective system isolation.*** In fact, NCG system interlocks are designed to effectively isolate the source and prevent momentary exceedances from propagating throughout the system and causing a broader venting episode of the entire system. The ability to isolate and vent sub-systems protects overall system integrity and minimizes potential emissions.

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[7] The State of Maine Department of Environmental Protection (Maine DEP), in comments filed for the RTR proposal, has opined that the EPA should maintain the venting allowances.

Given the myriad of other state emission limitations, limitations under NSPS or other applicable regulations, etc. that constrain emissions from the mill, facilities have in place best operating and management practices to identify, as soon as practical, the source of an unresolved venting episode. These operating practices also include troubleshooting procedures, approaches to isolate sub-systems, and instituting corrective actions.

Possible Elimination of Excess Emission Allowances Is Extremely Costly and Unachievable

In the AF&PA RTR Comments, we presented the potential capital costs that might be imposed on mills if the current venting allowances were eliminated - $1.6 billion. The costs included redundant control costs and collection systems for both LVHC and HVLC systems as well as installation of back-up strippers. This analysis was done very quickly in light of the short comment period and reflected the best analysis possible given the available data and input from member companies.

Since February, we have had a little more time to gather information from member companies, discuss other control technology requirements and costs with EPA, and examine the EPA data base in more depth. This has allowed AF&PA to develop a revised estimate of the potential cost of eliminating the excess emission allowances - $750 million. As the cost estimate document explains (see Attachment 8), the number of mills affected and the unit cost of investments were lower for a couple of key categories of costs, especially upgrades to collection systems and existence of alternative control/combustion devices.

While the cost is lower, it is still a very significant cost for the industry, especially considering that EPA has concluded that risks from this source category (in an analysis that included emissions that occur under the current excess emission allowances) are acceptable and there is no legal reason to change the excess emission allowance. Furthermore, investment of these hundreds of millions of dollars will NOT eliminate all venting periods, since some are part of normal operations and cannot be prevented in all circumstances. Thus, our conclusion remains that elimination of the excess emission allowances is cost-prohibitive, unnecessary, and would severely impact the ability of pulp and paper mills to operate.

* * * * * *

AF&PA appreciates the opportunity to comment on these issues. AF&PA wants to acknowledge the tremendous effort that OAQPS staff has taken since the issuance of the proposal to better understand pulp and paper operations and how Subpart S has been implemented and works, since none of the current staff were involved in

the original Subpart S rulemaking. They have made themselves available to discuss the data provided by our mills during the information collection request and the background analyses used to support the rule. As the attached information suggests, as well as our earlier comments, mill operations are very complex and each mill is unique given the array of equipment used, products made, and control options selected. AF&PA, NCASI and its member companies continue to stand ready to help explain the types and causes of venting that are inherent to our mill operations and provide information that is useful to the rulemaking proceedings.

Please direct any questions to Tim Hunt, AF&PA's Senior Director, Air Quality Programs, at (202) 463-2588 or at tim_hunt@afandpa.org.

Sincerely,

/s/
Paul Noe
Vice President for Public Policy

Enclosures

cc: Docket EPA-HQ-OAR-2007-0544
John Bradfield, EPA-RTP
Bill Schrock, EPA-RTP
Robin Dunkins, EPA-RTP
Peter Tsirigotis, EPA-RTP

LIST OF ATTACHMENTS

1. NCASI, The Collection and Transport of Noncondensible Gases (NCG) in NCG Systems at Pulp and Paper Mills: Background and Characteristics of NCG Systems and Summary of NCASI Survey Responses, June 27, 2012

2. Attachment A, NCASI Non Condensible Gas Venting Survey Questionnaire, May 2012

3. Attachment B, Recommended Good Practice Thermal Oxidation of Waste Streams in Black Liquor Recovery Boilers, The Black Liquor Recovery Boiler Advisory Committee (BLRBAC), February, 2012

4. Attachment C, NCASI, Experience with the Collection, Transport, and Burning of Kraft Mill High Volume Low Concentration Gases, August 2003

5. Attachment D, FM Global, Property Loss Prevention Data Sheets, January 2012

6. Attachment E, FM Global, Property Loss Prevention Data Sheets, May 2010

7. Attachment F, FM Global, Property Loss Prevention Data Sheets, May 2006

8. Cost Estimate for Elimination of Excess Emission Allowances, June 2012

    a. Attachment A to Cost Estimate, Excel File, Cost Estimate of Proposed Rules Changes to 40 CFR 63 Subpart S, Elimination of Excess Emission Allowances, June 2012

Attachment 1

NCASI, The Collection and Transport of Noncondensible Gases (NCG) in NCG Systems at Pulp and Paper Mills: Background and Characteristics of NCG Systems and Summary of NCASI Survey Responses, June 27, 2012

The Collection and Transport of Noncondensible Gases (NCG) in NCG Systems at Pulp and Paper Mills: Background and Characteristics of NCG Systems and Summary of NCASI Survey Responses

June 27, 2012

1.0 INTRODUCTION

Pulp and paper manufacturing utilizes an intricate network of interconnected processes. Unit operations are tied together by intermediate product flows, energy reuse, and chemical recovery cycles. Steam generated in power and recovery boilers is delivered to the process to satisfy system heat/energy demands. Recovered chemicals are brought back to the pulping and causticizing systems through the recovery cycle. There can be significant variability in operating rates, material throughputs, noncondensible gas generation, etc. at any one part of the mill. To some extent, throughput variability is ubiquitous and expected in continuous manufacturing operations. The interconnected nature of unit operations also contributes to variability. Many of these unit operations include multiple pieces of equipment, some operating in parallel, that create additional variability in flows, e.g., multiple batch digesters and blow tanks, operating on different cycles; multiple brownstock washers; and multiple pulp storage tanks feeding multiple paper machines.

Non-condensible gases (NCGs) generated in the pulping cycle are collected and transported in a complex and interconnected system, parts of which are under pressure while others are under vacuum. By virtue of their composition, these gases are potentially explosive and require extensive engineering controls to ensure safe handling. ***"Fail-safe" venting systems, interlocks, and permissives***[1] ensure that these gases are transported safely to the combustion device. These systems operate under very strict criteria designed to intermittingly vent to ensure that the system stays in balance and is operated without compromising worker safety or equipment integrity. There is also considerable heterogeneity in the components and configuration of NCG systems, viz., in the types and mix of sources collected, how the transport

[1] ***"Fail-Safe" Systems and Interlocks*** – An automatic control logic that results in an alarm or an automatic venting episode. Condition occurs when monitored parameter falls outside acceptable ranges. These systems are "fail-safe" because the venting event avoids a potential condition that compromises system integrity or results in an explosion. Non control logic / non computer controlled fail safe systems such as rupture disks, water loop seals, and P/V breakers, are also designed to vent if electronic systems fail. ***Permissives*** – A set of active conditions that need to be satisfied before NCG gases are introduced into the collection/transport system OR to the thermal destruction device, e.g., steam flow into steam ejectors and complete steam purge before introducing LVHC gases into transport system and control device.

and conditioning systems are configured to meet system-specific requirements and constraints, and the types of primary and secondary thermal destruction devices used.

As part of proposed amendments to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for the pulp and paper industry [*FR 76 (247) 81328-81358, December 27, 2011*], EPA has proposed to eliminate language pertaining to Startups, Shutdowns, and Malfunctions (SSM) to be consistent with the Agency's interpretation of the ruling in Sierra Club v. EPA. (Sierra Club v. EPA, 551 F.3d 1019, DC Cir. 2008). Additionally, EPA has also requested comments on whether it would be appropriate to remove or modify currently available NCG venting allowances and steam stripper downtime provisions (40 CFR 63.443(e), 40 CFR 63.446(g), and 40 CFR 63.459(b)(11)(ii)) of the 1998 NESHAP). EPA has requested additional information on the characteristics and drivers of intermittent NCG venting and on how facilities differentiate venting that occurs during SSM periods from those that occur during normal operation (intermittent safety-related venting not related to SSM conditions). In response to EPA's request for information, NCASI has conducted a survey to better understand the drivers of intermittent NCG venting episodes at pulp and paper facilities.

2.0 NCASI SURVEY ON PULP AND PAPER NCG VENTING AND STEAM STRIPPER PRACTICES

The NCASI survey on NCG venting (NCASI survey) was distributed to NCASI and AF&PA member companies on April 30, 2012. The survey attempts to answer specific questions posed by EPA on the following aspects of NCG venting:

a. Events during routine or normal operation that trigger intermittent NCG venting
b. Startup, shutdown, and malfunction (SSM) events triggering intermittent NCG venting, and
c. Approaches used by facilities to differentiate normal operation (and associated venting episodes) from SSM conditions

Survey questions were reviewed by technical staff at EPA's Office of Air Quality Planning and Standards (OAQPS) prior to distribution. In response to a specific request by OAQPS during this review, the survey also requested information on other applicable restrictions imposed by States, if any, on recording, reporting, and classifying NCG venting episodes. The survey questionnaire is provided as **Attachment A**.

3.0 ORGANIZATION OF THIS DOCUMENT

This document provides a primer on the background and characteristics of NCG systems at pulp and paper mills, a compilation of available information on NCG constituents, and a discussion of the major design considerations involved in building and operating these systems. Secondly, industry responses to specific questions in the NCASI Survey are compiled along with

associated observations and conclusions. In addition to summarizing the key takeaways from the NCASI survey, this report also includes the following documents in Addenda;

- Technical assessment report developed by the Black Liquor Recovery Boiler Advisory Committee (BLRBAC) on safety and control system considerations while burning flammable NCGs in recovery furnaces. This report further highlights the complexity of NCG transport systems and illustrates the need for adequately designed control systems to maintain system integrity and safety **(Attachment B)**.

- NCASI Special report 03-03 summarizing industry experience with HVLC systems. This report provides additional background information on NCGs and the various components that make-up LVHC and HVLC systems **(Attachment C)**.

- Selected compilations from Factory Mutual Insurance Company on recommended practices for the design, operation, and maintenance of chemical recovery furnaces, wood fuel boilers, and for the combustion of NCGs.[2] Specifically, FM global has provided suggested guidelines for the design of boiler pressure parts and burning of liquid fuels, gaseous fuels, and auxiliary fuels like NCGs. These documents are also used as guidelines when assessing insurability of systems (**Attachments D, E, and F)**.

4.0 BACKGROUND ON KRAFT MILL NCGs AND THEIR COMBUSTIBILITY[3]

Characterization studies carried out on kraft mill NCGs indicate that the main components are methanol, turpentine (predominantly α-pinene), hydrogen sulfide (H_2S), methyl mercaptan (CH_3SH), dimethyl sulfide (DMS) and dimethyl disulfide (DMDS). The sulfur compounds present in NCG are collectively referred to as total reduced sulfur (TRS) compounds. The NCGs are generated and released from pulping systems, turpentine recovery systems, brownstock washers, liquor evaporation, and liquor storage tanks.

4.1 Characteristics of combustible gases

The protection of personnel, public, and equipment remains in the forefront when designing collection and transport systems for NCGs, given its combustible components. Equipment designers evaluate the potential for explosions during the first step of the design phase. Several studies have been carried out in order to better understand the dangers

[2] Designing piping for auxiliary fuel gas and LVHC gases – Data Sheets 6-5, Section 2.2 of 7-32, and 7-54
Designing ductwork for HVLC gases – Data Sheet 7-78.
Data sheets available for download at http://www.fmglobal.com/FMGlobalRegistration/Downloads.aspx

[3] Excerpts taken from NCASI Special Report 03-03 – "Experience with the collection, transport, and burning of kraft mill high volume low concentration gases," Vipin K. Varma, PhD, August 2003.

associated with transporting combustible gases. These studies indicate that the flammability and ignitability of combustibles are dictated by the five characteristics described below.

Lower Explosive Limit (LEL): The lower explosive limit (LEL) of a combustible component in a gas is defined as the minimum concentration by volume at which the gas ignites when provided with enough oxygen and an ignition source and continues to burn when the ignition source is removed.

Upper Explosive Limit (UEL): The UEL of a combustible component in a gas is the maximum concentration above which the gas will not ignite due to a lack of oxygen, even when provided with an ignition source.

Flammability Range: Combustible components in NCGs will ignite when their concentrations are in the range of percentages from the LEL to the UEL, if provided an ignition source.

Flame Propagation Speed: The speed at which the flame travels from the point of ignition, through a flammable vapor, along the length of a long pipe (such as the one used to transport NCGs to the combustion device).

Auto Ignition Temperature (AIT): The approximate lowest temperature at which a flammable gas or vapor-air mixture will spontaneously ignite without a spark or a flame.

4.2 Characteristics of Kraft Mill NCGs

Kraft mill NCGs are characterized based on the composition of the main constituents into four categories, viz., low volume high concentration (LVHC), high volume low concentration (HVLC), stripper off-gases (SOG), and chip bin vent gases. Extensive characterization studies have established the concentration ranges of main combustible components in these various streams.[4] The LEL and UEL values, flame speeds, and auto ignition temperatures for the main kraft mill NCG components are summarized in Table 1.[5] Main characteristics of these gases are summarized below.

LVHC gases (concentrated NCGs)

- Consist of relatively high concentrations of TRS compounds and air depleted of nearly half of its oxygen
- TRS compounds are typically present at concentrations in the flammable range i.e., between the LEL and UEL

[4] Burgess, T. L. 1998. Collecting and Burning Noncondensible Gases. Kraft Recovery Operations Short Course Proceedings. Section 4.2: 1-19. Atlanta, GA. TAPPI Press.

[5] Burgess, T. L., Kjerulf, E. B., and Tenn, T. I. 1984. Design Considerations for High Concentration Low Volume Noncondensible Gas Systems. TAPPI Journal 67(9): 92-96.

- Since these gases do not contain sufficient oxygen to allow for ignition, LVHC systems are designed with the objective of minimizing air ingression and thereby reducing the explosion hazard.
- LVHC gases are therefore transported using steam, instead of air, as the motive force.

Table 1. Combustion Properties of Kraft Mill NCGs in Air [5]

Compound	Explosive Limits, % volume		Flame Speed, ft/sec (m/sec)	Auto Ignition Temp, °F (°C)
	LEL	UEL		
H_2S	4.3	45.0		500 (260)
CH_3SH	3.9	21.8	1.8 (0.55)	
CH_3SCH_3 (DMS)	2.2	19.7		400 (206)
CH_3SSCH_3 (DMDS)	1.1	8.0		572 (300)
α-Pinene	0.8	6.0	500 (154)	487 (253)
Methanol	6.7	36.5	1.5 (0.5)	867 (464)

Stripper off-gases (SOG)

- Mixture of methanol, TRS compounds, turpentine[6] , and saturated steam
- Methanol concentrations in SOGs are typically greater than methanol concentrations in LVHC gases.
- Contain condensible components unlike in LVHC gases.

HVLC gases (dilute NCGs)

- Combustible components in HVLC gases, or dilute NCGs, are typically present at levels well below their individual lower explosive limits (LEL).
- Oxygen levels in HVLC gases approach that of atmospheric air.

Chip bin vent gases

- The combustible components in chip bin vent gases are also present at concentrations well below their respective LELs.

[6] Occasional carryover of turpentine in foul condensates

- Chip bin vent gases are different from HVLC gases in that they have the potential to contain significant quantities of turpentine, sometimes at concentrations approaching its LEL.

5.0 DESIGN AND OPERATING PHILOSOPHIES FOR NCG SYSTEMS [7, 8, 9]

5.1 NCG Collection and Transport Systems

The governing principles for designing NCG collection and transport systems have been established based on years of experience and are well documented in literature. The primary consideration in the design of kraft mill NCG systems is to prevent explosions. ***Explosions in collection and transport systems are caused by the coexistence of all three primary ingredients, viz., combustibles in the flammable range, sufficient oxygen, and an ignition source. Therefore, the strategy adopted for the design and operation of these systems is to prevent explosions by excluding one or more of the above-mentioned components from these systems at all times.*** Key design philosophies are summarized in the following section and additional details are provided in NCASI Special Report 03-03 and NCASI Technical Bulletin 469.

LVHC systems

As discussed earlier, LVHC systems typically include vent gases from turpentine recovery, blow heat recovery, evaporator hotwell, foul condensate storage tanks, and digester relief vents. The combustible components in these gases are typically present within the flammable range (between LEL and UEL). However, LVHC gases, as collected, generally have insufficient oxygen to cause ignition. Hence, the design philosophy for LVHC systems is to prevent air ingression and eliminate the explosion hazard by oxidant concentration reduction. Fans used for transporting LVHC gases have provided ignition sources in the past, due to hot spots in the casing, bearing failure etc. Consequently, steam ejectors are used as motive force for LVHC gases. This provides an additional line of defense against explosions by eliminating ignition sources and providing a safe motive force without air ingression. Condensate accumulation has been known to cause two-phase flows, in the presence of even minimal amounts of turpentine, leading to the buildup of static electricity that could generate a spark and lead to an explosion. Therefore, system designers incorporate an additional line of defense

[7] Allen, T. 2001. NCG handling and incineration concerns drive need for safe system design. Pulp and Paper 2001(3): 43-51.

[8] Barynin, J.A., Berg, L., and Lee, B. 1993. Recent trends in NCG disposal system design. Pulp and Paper Canada 94(12): 74-78.

[9] NCASI Technical Bulletin No. 469 – Collection and burning of kraft non-condensible gases – current practices, operating experience, and important aspects of design and operation, Parts I and II, 1985

against explosions by advising that the system be operated without condensate accumulation and with minimal turpentine entrainment. The latter involves optimal operation of the turpentine recovery system.

SOG Systems

Like LVHC gases, SOGs are collected and transported with minimal air ingression. SOG streams contain increased levels of methanol and saturated steam at temperatures higher than that of LVHC streams. SOG stream can occasionally contain turpentine due to its carryover into foul condensates. SOG streams do contain condensible components, as a result of which they are not combined with LVHC streams prior to incineration. The temperature differential between the streams could result in condensation of SOG constituents, thereby creating two-phase flows and the potential for buildup of static electricity. The prevalent practice is to collect and transport each stream using a dedicated system. Steam ejectors are used as motive forces when steam strippers are operated at or near atmospheric pressure. Some system designers exclude steam ejectors when the steam strippers operate under pressure and provide sufficient motive force at the collection source.

HVLC Systems

Unlike LVHC gases, HVLC gases contain significantly lower TRS concentrations and oxygen levels approaching that of ambient air. Sources of HVLC gases include brown stock washers, deckers, O_2 delignification systems, knotters, screens, intermediate storage tanks, filtrate tanks, and weak liquor storage tanks. The design philosophy with these gases is to eliminate the explosion hazard by ensuring that the combustibles remain at concentrations well below their LEL. This is accomplished by further diluting the sources with sufficient air to ensure that the TRS compound concentrations remain well below their LEL values. Fans are generally used as motive forces for HVLC gases. System designers advise that HVLC gases should not be combined with LVHC gases and SOG prior to incineration since the associated dilution may move the combustible concentrations in the LVHC stream, generally maintained above the UEL, into the flammable range.

Chip Bins

Vent gases from chip bins utilizing flash steam are different from LVHC gases because they contain higher levels of oxygen. They are also different from HVLC gases because they can potentially contain turpentine at levels approaching its LEL. System designers recommend that chip bin vent gases be collected as part of the HVLC system, because the increased levels of

oxygen in these streams make it unsuitable to be collected along with LVHC streams. However, when pulping softwood, it is common practice to remove turpentine by passing these gases through a cooler or a condenser, before introducing them into the HVLC stream. This is because condensate accumulation and turpentine entry into the system can potentially create ignition sources. Since water and turpentine are immiscible, they decant in the pipeline, cause two-phase flows and may build sufficient static charges to ignite the turpentine as it cascades down a pipe run.

It is common practice to design NCG systems to operate at gas velocities above the flame propagation speed of the combustible components. Experience indicates NCG systems can be designed to operate at gas velocities greater than the flame propagation speeds of the TRS compounds and methanol. However, these systems cannot be operated at velocities greater than the flame propagation speed of turpentine. It has been reported that maintaining gas velocities between 50 and 100 ft/sec provides an adequate safety factor during operation. This is another reason why effective turpentine removal is critical when operating these systems. It is also recommended that all systems be adequately grounded in order to prevent the buildup of static electricity. Flow rate and temperature monitoring, with interlocks, immediately upstream of the combustion device protects against flame propagation hazards.

5.2 Thermal Destruction Devices

In addition to the safety considerations associated with the collection and transport of NCGs, system designers need to adequately design the NCG introduction system into the incineration device. Design considerations for NCG introduction (and control) systems for thermal oxidizers, boilers, recovery furnaces, and lime kilns are to ensure that the devices (a) are ready to receive NCGs, (b) can achieve complete combustion, and (c) are equipped with monitoring and control systems to prevent NCG introduction into unsafe combustion environments. As discussed earlier, BLRBAC has provided detailed recommendations on best practices and procedures while burning NCGs in recovery furnaces. Factory Mutual Insurance Company has developed a series of data sheets with recommendations on the construction of NCG systems, the control equipment and permissives that need to be in operation, and on how to operate and maintain boilers and recovery furnaces.[10]

LVHC gases can be transported from the collection point to the incineration device using the two approaches listed below.

a. Vapor phase transfer system

b. Conditioned gas transfer system

[10] Provided as Attachments D, E, and F

In a vapor phase system, NCGs are directly transported from the collection point to the incineration device. These systems are generally heavily insulated and heat traced using steam, in order to prevent the accumulation of condensible components like methanol, water, and turpentine. By contrast, the intent of a conditioned gas transfer system is to reduce the amount of water vapor and condensible components being incinerated. A conditioned gas transfer system includes the following additional components.

a. Gas cooler/Condenser

b. Mist eliminator

c. Indirect steam pre-heater to re-heat gases

The condensates from the cooler/condenser and mist eliminator are typically transferred to the foul condensate treatment system. [11] The gases are re-heated after the condensates are removed so that the operating temperature is increased and process upsets due to further condensation are minimized. Conditioned gas transfer systems are especially critical when burning NCGs in recovery furnaces, as discussed below.

The incineration of LVHC, HVLC, and SOG in recovery furnaces presents operational problems that far exceed the safety, gas flammability, and tube explosion concerns that designers tackle in the case of thermal oxidizers, conventional boilers, and lime kilns. A significant added concern is the possibility of furnace explosions. Furnace explosions can be broadly classified into the three categories listed below.[12]

a. Smelt-water explosion

b. Auxiliary fuel explosion, and

c. Pyrolysis gas explosion

Smelt-water explosions are attributed to the introduction of moisture into the furnace. Although a majority of these explosions are caused by the failure of boiler pressure parts inside furnaces, they can also be the result of introduction of moisture through LVHC, HVLC, and SOGs. Auxiliary fuel and pyrolysis gas explosions are caused by the uncontrolled ignition of auxiliary fuels or pyrolysis gases accumulating in the upper furnace region without being incinerated. LVHC gases are similar to auxiliary fuels in that they have significant heat value. Therefore, explosions can occur when these gases are introduced into the furnace in the absence of a controlled ignition source. Explosions are also possible when HVLC gases,

[11] Barynin, J.A., Berg, L., and Lee, B. 1993. Recent trends in NCG disposal system design. Pulp and Paper Canada 94(12): 74-78.

[12] Grace, T. M. Recovery Boiler Explosion Experience. 1992. TAPPI International Chemical Recovery Conference Proceedings 25-31. Atlanta, GA. TAPPI Press.

generally maintained well below their LEL limits, get concentrated in the furnace to within flammability limits and accumulate without being completely destroyed.

5.3 NCG System Interlocks and Permissives

The primary objective of safety interlocks in NCG systems is to isolate and vent portions of the system during unsafe conditions. Additionally, when the system becomes unstable or when incineration permissives are lost, safety interlocks allow for automatic venting and prevent potential explosions. Interlocks are typically set up to warn (alarm) plant operators when the "low/high" set-point is reached and vent when the "low-low/high-high" set-point is exceeded (***alarm and venting thresholds, respectively***).

The following is a list of common interlocks that result in an alarm, and if unresolved, a venting episode:

1. Steam flow from boiler or recovery furnace falls below predetermined cut-off value (e.g. 30% of Maximum Continuous Rating (MCR) for boilers and 50% for recovery furnaces). Loss of flame, if incineration device is a thermal oxidizer.

2. HVLC gas flow at the outlet of the main HVLC fan falls below acceptable threshold. In the case of LVHC gases, temperature or pressure measurements at the outlet of the steam ejector (or for steam supply into the ejector) fall outside acceptable ranges. Differential pressure alarms are also common as a way to identify plugged flame arrestors.

3. System pressure at the HVLC cooler or re-heater increases above the acceptable threshold.

4. Temperature at the exit of the LVHC or HVLC cooler exceeds acceptable thresholds. In the case of HVLC gas re-heaters, if the temperature at the re-heater exit falls below acceptable thresholds.

5. Temperature at the exit of the HVLC gas re-heater increases above the "high-high" set-point, indicating potential burn-back.

6. HVLC fan speed falls below the "low-low" set-point. When steam ejectors are used (as in the case of LVHC and SOG), when steam flow to the ejector falls below the "low-low" set-point or total system flow exceeds acceptable ranges.

7. When alarm and vent thresholds for LEL meters, when used near the incineration device, are exceeded.

8. Differential pressures across flame arrestors, mist eliminators, or condensate drains exceed acceptable thresholds.

In addition to overall transport system interlocks, portions of the system are also designed to be isolated and vented when unsafe conditions exist without having to take the entire system off-line. For instance, chip bin collection systems are typically equipped with the following dedicated interlocks that prompt localized venting:

1. Temperature at the exit of the cooler/condenser rises above the alarm threshold – this can be a surrogate for turpentine carryover.

2. Measurements from dedicated LEL meters exceed alarm thresholds.

3. Chip bin level falls below acceptable thresholds. In some cases, when the chip bin level reaches the low threshold, flash steam input into the chip bin is cut-off as a preemptive action.

As summarized in this section, the collection, transport, and treatment of NCGs in incineration devices is a complicated endeavor and involves the smooth operation of multiple systems while maintaining safety and system integrity. The primary concern is the potential for explosions. As a consequence, boiler manufacturers and insurance providers recommend the use of comprehensive control systems to ensure the safe operation of these systems. Schematics of system components are provided in Figures 1 and 2 below.

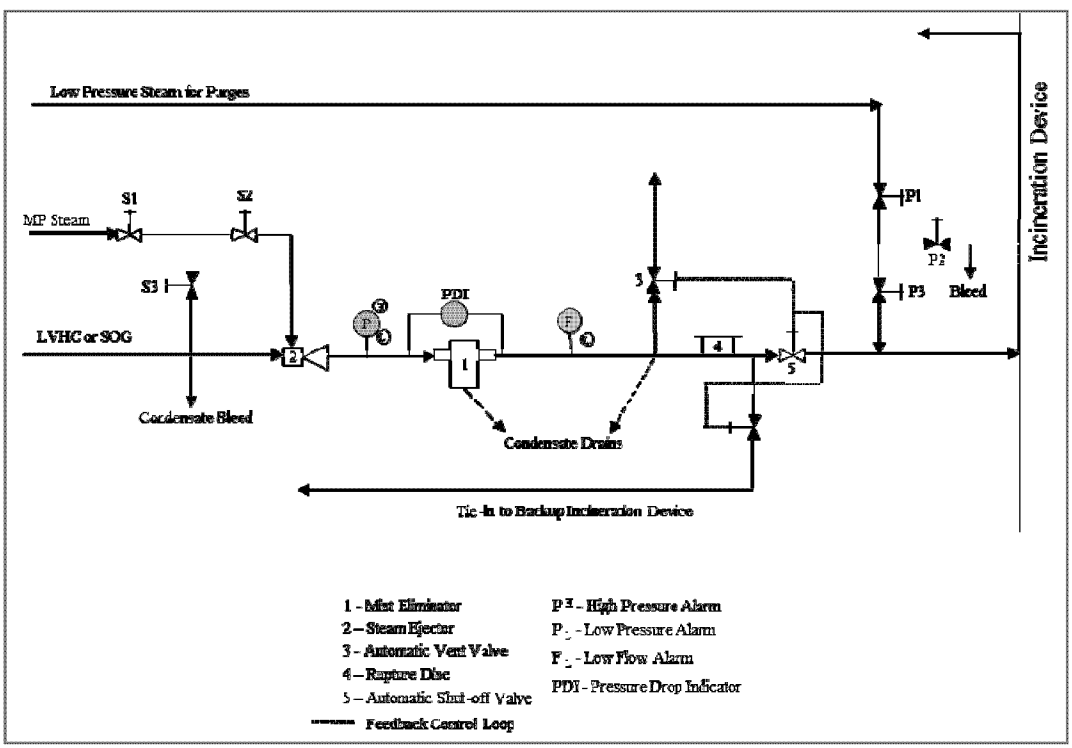

Figure 1. Schematic of typical vapor phase NCG Transport and Introduction System

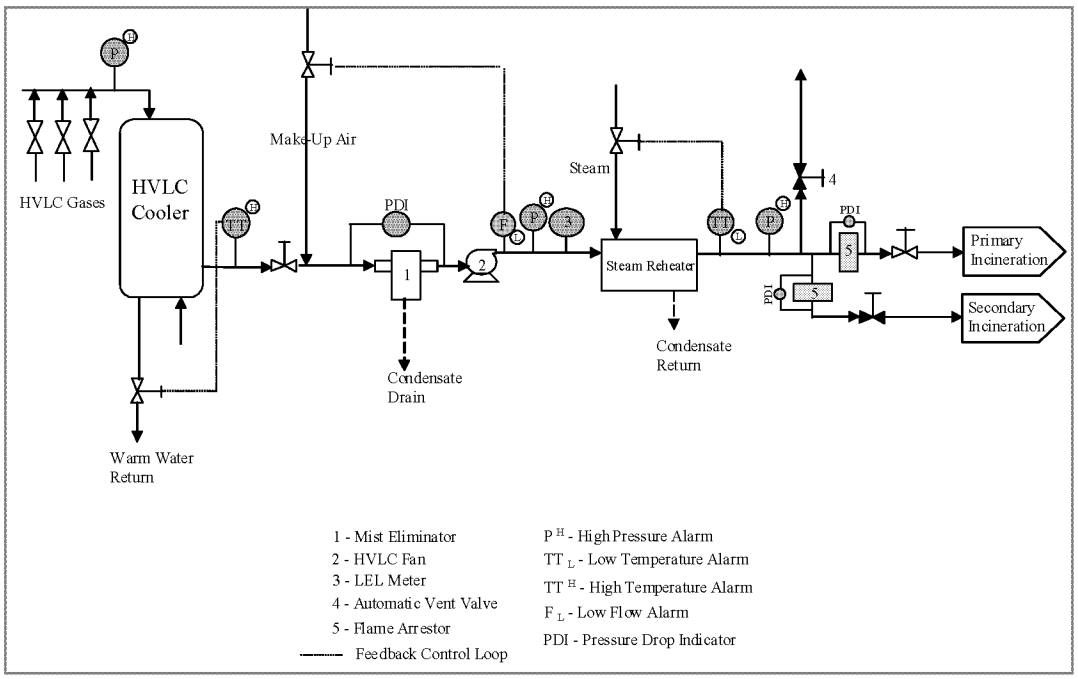

Figure 2. Schematic of typical conditioned gas HVLC transport and introduction system

6.0 SUMMARY OF INDUSTRY RESPONSES TO THE NCASI SURVEY

6.1 Background and Key Takeaways

The NCASI NCG survey was conducted in order to answer specific questions raised by the EPA, in the December 27, 2011 proposal, on intermittent NCG venting that occurs during routine or normal operations and covered under existing venting allowances. Facilities were requested to provide qualitative information, based on prevailing process knowledge and experience, on the types of events triggering these intermittent venting episodes. Additionally, facilities were also requested to identify operating conditions or threshold operating parameters used to differentiate SSM venting events from those occurring during routine operation. ***A total of 81 kraft mills responded to the survey***. This report analyzes survey responses and draws collective conclusions on the types of events triggering intermittent venting. Given the large number of survey responses and the time constraints that EPA has for reviewing these results, this report is designed to provide comprehensive summarizes of survey responses, discuss survey results in the context of the questions being posed, and draw relevant conclusions in light of survey results and the system characteristics presented above.

Intermittent venting episodes of the NCG system can be broadly categorized into the following:

a. Events occurring during equipment startup, shutdown, and malfunctions (SSM) periods, and
b. Events occurring during routine or normal operation.

Routine venting events can largely be attributed to process variability. As facilities have gained more experience in operating NCG systems, they have progressed along the learning curve and learned to manage some of this process variability. ***However, it is impossible to eliminate all sources of process variability – hence the term inherent.*** Inherent process variability inevitably results in the tripping of control system interlocks and intermittent venting episodes. The primary objective of the NCG control system and associated interlocks is to (a) prevent NCGs from approaching flammability limits, (b) minimize the potential for unsafe conditions in the transport system and at the thermal destruction device, and (c) maintain safety, system integrity, and prevent explosions. The network of alarms designed into NCG systems serves to provide operating boundaries for facilities and greatly minimizes venting episodes. These alarms facilitate the secondary, but equally important, objective of minimizing the release of TRS compounds that cause objectionable odor in the community. In spite of tight control and operation, circumstances do arise that result in the tripping of vent thresholds. Given the primary objective of promoting safety and preventing explosions, facilities have to mitigate these conditions using "fail-safe" strategies, viz., through intermittent venting.

Key takeaways from the NCASI survey are summarized below. More details and data are provided in the remainder of this report.

1. ***Intermittent venting episodes can occur during routine or normal operation.*** These events are triggered by the expected inherent process variability and by transient conditions in the collection, transport, and conditioning equipment. This results in the tripping of safety and system integrity interlocks. These venting episodes and the events that trigger them are not malfunctions of associated equipment as they continue to operate as designed and within expected ranges. These venting episodes are critical to maintaining system integrity and preventing catastrophic scenarios that could result in unsafe conditions for workers, equipment damage, and explosions.

2. ***Intermittent venting can also be caused by Startup and Shutdown (SS) events.*** In the context of the NCG system, Startup and Shutdown (SS) conditions are distinct and therefore unlike routine operations.

- A subset of SS conditions trigger distinct interlocks and permissives within the NCG transport system or sub-systems, thus resulting in intermittent venting episodes.
- Some of the intermittent venting during SS conditions can also be traced to increased levels of process variability not expected or observed during routine operation.

3. ***A vast majority of facilities use threshold parameters to differentiate routine operating periods from startup and shutdown (SS) periods. Others have defined specific actions that are required to be carried out in order to startup or shutdown a piece of equipment or process, thus differentiating the two.***

4. ***Survey results indicate that problems related to transport system equipment (gas conditioning equipment, sensors, and fiber/liquor separation equipment) are as prevalent as malfunctions related to process equipment and thermal destruction devices.*** Given the ability to isolate sub-systems, the former are less disruptive to overall NCG system operation than the latter. Transport system equipment problems also can be triggered by inherent process variability. Adequate consideration of the triggering events is therefore justified, before these are all grouped as malfunctions as defined by the rule.

5. ***Steam stripper downtimes do not reflect "no HAP control" scenarios.*** Facilities routinely route their condensates to biological wastewater treatment systems during steam stripper downtime periods and thereby maintain high levels of treatment for methanol and major non-methanol HAPs.

6. ***A handful of states do impose limits on the duration of individual LVHC system vents. This is similar to the 40 minute limit imposed by the state of Maine.***[13] Individual LVHC system vents are limited to 30, 60, and 240 minutes in AR, OR, and AL, respectively.

Other pertinent takeaways relating to specific technical and operational aspects of NCG systems are as follows:

7. ***Intermittent venting is a consequence of "Fail-safe" systems, interlocks, and system permissives.*** These interlocks and the resulting intermittent venting are an essential "first line of defense" against system failures and potential hazardous conditions, including catastrophic explosions. Some are attributed to inherent process variability, others to SS conditions, and a third category can be the result of malfunctions.

8. ***Interlocks and permissives are essential components of any NCG system.*** These protections are designed into systems in order to prevent equipment damage, injuries,

[13] The State of Maine Department of Environmental Protection (Maine DEP), in comments filed for the RTR proposal, has opined that the EPA should maintain the venting allowances.

and potential fatalities. These are integrated into system design and considered as "prerequisites of insurability" by insurance companies. As discussed earlier, the BLRBAC recommendations and Factory Mutual Guidelines on the design and operation of NCG systems, both illustrate the importance of these permissives. Their suggested guidelines are widely followed in designing these systems and in carrying out insurance audits.

9. ***Intermittent venting episodes that occur during normal operation frequently resolve themselves or can be resolved through effective system isolation.*** NCG system interlocks are designed to effectively isolate the source and prevent momentary exceedances from propagating throughout the system and causing a broader venting episode of the entire system. The ability to isolate and vent sub-systems protects overall system integrity and minimizes potential emissions.

6.2 Detailed Discussion of Survey Responses

1. Intermittent NCG venting in Pulp and Paper mills can be caused by events that occur during routine or normal operation. These events can be traced back to inherent process variability that results in the tripping of safety and system integrity interlocks. These events are not malfunctions, as defined by the regulation, and the resulting venting episodes are an essential "first line of defense," for preventing the onset of more dangerous and potentially catastrophic conditions in the NCG system.

   Facility responses to the following questions have been summarized in this section:

   Q8. Rank or select the top six causes of routine venting events in the LVHC System

   Q10. Rank or select the top six causes of routine venting events in the HVLC System

LVHC SYSTEMS

Four (4) most identified events that occur during routine/normal operation and trigger intermittent venting

As discussed earlier, a multitude of normal operating scenarios can cause intermittent venting of LVHC NCGs. These are all transient in nature and frequently resolve themselves or can be rectified with minimal intervention. The following four scenarios were the top triggering events, associated with LVHC systems, identified by facilities responding to the survey. (Ranked in the descending order on how frequently they were identified by facilities).

# (Area)	Conditions Occurring during Normal Operation	Facilities Identifying these Conditions[1]	1. Cause 2. Reason for venting
1 (Control device)	Primary Combustion Device Not Available (not due to malfunction)	51	– Loss of permissives – Safety-related
2 (Transport system)	Pressure / Temperature Interlocks in Gas Transport System	42	– Inherent variability – Safety-related
3 (Transport system)	Pressure / Temperature Parameters on Process Equipment Outside Normal Operating Ranges	40	– Inherent variability – Safety-related
4 (Control device)	Switching between Incineration Points	36	– Steam purge requirement – Safety-related

[1]Facilities were given the option to select ***all applicable*** reasons for venting during normal operation

Two of the four events most frequently identified by facilities in the survey relate to operating conditions in the control device (# 1 and #4). # 2 relates to process swings and the resulting tripping of system interlocks in the transport system. # 3 is predominantly driven by momentary swings in the process areas that result in pressure or temperature parameters exceeding normal operating ranges. More details on these events are provided below.

 # 1 – Primary combustion device not available (not due to malfunctions) – The combustion device becomes temporarily unavailable due to the momentary loss of NCG burning permissives. This condition is not caused by malfunctions of associated equipment and affects only the ability of the control device to burn NCGs. Examples include the following:

- Transient changes in process steam/energy demands in the mill (inherent variability in upstream processes or swings in production rates) cause variations in steam header pressure. This could lead to changes in fuel feed rates and/or fuel mixes and trip NCG burning permissives.
- A reduction in steam demand could result in steaming rates being reduced below a certain threshold, thus preventing the burning of NCGs in the boiler or recovery furnace.

When steaming rates in a boiler or a recovery furnace fall below a certain threshold percentage of the maximum continuous rating (MCR), it triggers a "boiler permissive" that prevents NCGs from being burned in the boiler. NCG burning is not recommended at low MCR as the resulting lower combustion temperatures increases the potential for incomplete combustion of NCGs, which is an unsafe operating condition. In the case of a thermal oxidizer, a temporary flameout could result in loss of the "burner permissive" and result in NCG venting

until the flame is relit and the unit is stabilized. These temporary losses of permissives are not malfunctions of the associated equipment but primarily driven by inherent process swings and variations. These are typically resolved when the associated parameters stabilize and the NCG burning permissive is restored.

When the primary combustion device becomes temporarily unavailable, LVHC gases are typically routed to the secondary combustion device. In the case of LVHC systems, this transfer can occur without intermittent venting if and only if all transfer piping conveying the gases to the secondary combustion device is maintained in "ready" mode. This condition is satisfied by maintaining a continuous steam purge through all transfer piping, thus allowing for ventless transfer of gases. Switching between incineration points was another routine/normal operating condition identified in the survey (#4 below).

 # 2 – Pressure / Temperature Interlocks in Gas Transport System – These interlocks can be tripped due to exceedances of either the flow rate OR temperature set-points in the transport system. Pressure variations can frequently be caused by inherent swings in production rates or, as in the case of batch digester mills, pulping blow sequences. Pressure interlocks can also trip due to flow balancing issues within the various branches of the NCG system. Temperature interlocks in the transport system are instituted as a way to prevent excess carryover of hot gases, foam, and liquor. They are also used to detect flame blow-backs through NCG piping, inadequate cooling of NCGs, etc. For instance, NCG temperatures could temporarily exceed alarm limits when condensers/coolers are over-extended, either due to variability in cooling water temperatures or due to excess NCG flows. As facilities have gained operating experience with NCG systems, they have increasingly reduced manageable process variability. However, inherent process variability still results in the tripping of these essential safety interlocks.

#3 - Pressure / Temperature Parameters on Process Equipment outside Normal Operating Ranges – This is another category of events that occur during normal operation and can trigger intermittent venting. Unlike # 2 above, interlocks at or near process equipment are designed to effectively isolate any variability that occurs within process vessels from propagating into the transport system. Isolating the process vessel during temporary periods of process upsets allows the facility to isolate the problem and continue operating the NCG system. The ability to prevent the propagation of isolated process variability into the transport system, through the use of a local interlock (a) effectively isolates the source of the variability, (b) averts the onset of a more dangerous and potentially catastrophic condition in the NCG system, and (c) minimizes potential venting as other components of the system continue to operate normally.

#4 – Switching between incineration points – This was the identified as the fourth most prevalent reason for intermittent venting during routine operation. The driver for this venting episode is primarily safety and system integrity. As discussed in Section 5.1, flammability

considerations prevent the use of air as the motive force while transporting LVHC gases.[14] Consequently, LVHC gases are transported to the combustion device using steam as the motive force. LVHC systems are designed and operated to prevent any ingression of air because of the potential for these gases to move into the flammability range (between the LEL and UEL). The sequence of events that lead to intermittent venting due to switching between incineration points is given below:

- Facilities operating LVHC systems have a backup combustion device that is "ready" to receive LVHC gases.
- Given the need to prevent air ingression, transfers of LVHC gases from primary to secondary incineration devices are preceded by steam purges to remove entrained air from transfer piping. This steam purge requirement is frequently a permissive built into the control logic.
- As a consequence, any unplanned switching of LVHC gases between incineration devices results in a momentary venting episode while the steam purge requirement is being satisfied.

The only alternative to this momentary venting episode would be to maintain a constant steam purge throughout all transfer piping between the "divert point" and the secondary incineration device, thus continuously maintaining the permissive. This alternative is infeasible and economically impractical in many cases due to the distance between the primary and secondary control device and the significant energy penalty associated with maintaining the constant steam purge.

These four identified scenarios occur during routine operations and can trigger intermittent venting episodes. These conditions are not caused by malfunctions of any associated equipment and are primarily the result of inherent process variability. The associated venting episodes are designed into the control system to maintain safety and system integrity.

[14] The concentrations of organic compounds in LVHC (concentrated NCG) systems are typically above the UEL thresholds. The ingression of air could potentially dilute these gases to within flammability ranges (between the LEL and UEL), while providing oxygen to support combustion. This potential explosive scenario is avoided by minimizing air entry into HVLC systems. More details on the characteristics of NCGs and transport systems are provided in NCASI Special Report 03-03 (NCASI 2003).

Other prevalent events that trigger intermittent venting in LVHC Systems during routine operations

#	Conditions Occurring during Normal Operation	Facilities identifying these conditions	1. Cause 2. Reason for venting
5	Flow balancing issues or tripping of flow interlocks	27	– Inherent variability – Safety
6	Steam Interlocks in Gas Transport System	22	– Inherent variability – Safety
7	Back-up combustion device not available	20	– Loss of permissives – Safety

The LVHC system is an interconnected network of transport piping that collects NCGs from various sub-systems and transports these gases to the combustion device. Some of these systems tend to cycle (e.g., flows from the digester and turpentine recovery system) while others are continuous (e.g., non-condensible gases from the evaporator system). Given these varying characteristics in flows, LVHC systems are designed with flow interlocks that monitor and protect the system from excess flows, gas blow back into the process when sub-systems under lower pressure operate with reduced flows, etc.

Steam interlocks are tripped in LVHC systems when variations in process steam demands result in momentary swings in steam flows to ejectors. In the absence of the motive force, LVHC gases are forced to vent, thus preventing accumulation inside the transport system and the potential for other dangerous consequences.

There are instances when, immediately following an LVHC gas diversion, the secondary combustion device also becomes unavailable due to the momentary loss of permissives. Once again, this control device unavailability is not due to a malfunction of associated equipment but merely a safety mechanism designed to prevent the burning of flammable NCGs in an unsafe combustion environment. These instances also result in venting episodes.

HVLC SYSTEMS

The following four conditions have been identified as the top events associated with HVLC systems by the 48 facilities responding to the survey that had HVLC systems.

#	Conditions Occurring during Normal Operation	Facilities identifying this condition	1. Cause 2. Reason for venting
1	Primary Combustion Device Not Available (not due to malfunction)	27	– Loss of permissives – Safety
2	Pressure / Temperature Interlocks in Gas Transport System	18	– Inherent variability – Safety
3	Pressure / Temperature Parameters on Process Equipment Outside Normal Operating Ranges	14	– Inherent variability – Safety
4	Flow interlocks in transport system (overall system flow, make-up air flow, etc.)	14	– Inherent variability – Safety

Once again, as discussed under the section on LVHC venting episodes, the leading event that occurs during normal operation and triggers venting of HVLC systems was the unavailability of the combustion device due to the momentary loss of permissives. This observation is expected given that the loss of the primary control device was also the #1 driver for venting episodes in LVHC systems. The #2 and #3 most frequent events are similar to those discussed earlier under LVHC systems, except that it pertains to the HVLC systems in this case. The #4 condition identified in the survey (flow interlocks) stems from inherent fluctuations in HVLC gas flows from the various components of the system like weak liquor storage tanks, brown stock washer area storage tanks, brown stock washers (BSWs), etc.

KEY TAKEAWAYS ON INTERMITTENT VENTING EVENTS DURING NORMAL OPERATION

The following aspects are worth reiterating about the operating conditions, interlocks, and the venting episodes described above:

- The ***inherent process variability*** that triggers these events cannot be reasonably prevented through corrective actions and is an unavoidable part of normal, continuous operations.
- The conditions triggering these venting events are normal and expected fluctuations in operations rather than equipment failures or operator errors, and therefore would not be considered malfunctions of equipment, processes, or control devices.
- These venting episodes are designed to promote safety and system integrity while averting the potential for accumulation of NCG gases within transport systems and control devices.
- Although facilities continue to make strides in reducing manageable process variability, there is inherent variability in many of the relevant processes and waste streams that cannot feasibly be eliminated.
- These venting events are necessary both for technological and operational reasons.

- Lastly, the elimination of venting allowances for normal operating periods would jeopardize system integrity, compromise safety considerations, and ultimately render safe and continued operation infeasible.

2. Startup and shutdown (SS) conditions are distinctly different from normal operation. A subset of SS conditions trigger distinct interlocks and permissives within the NCG transport system or sub-systems, thus resulting in intermittent venting episodes. Some of the intermittent venting during SS conditions can be traced to unusual levels of process variability not observed during normal operation.

The NCASI survey has identified several unique conditions, occurring during startup and shutdown periods, that result in the temporary loss of permissives or can trip control interlocks. These conditions are ***unlike those observed during normal operation and are typically not encountered when the mill is operating in stable production mode.*** The ~ 80 facilities responding to the survey have identified the following SS conditions that lead to venting episodes of NCG systems:

#	Venting Episodes Related to Startup / Shutdown Conditions	Facilities Identifying this Condition	1. Cause 2. Reason for Venting
1	Isolated venting of process equipment before reaching steady state	45	– SS Condition – Isolate system and prevent propagation into other areas
2	Inability to resolve interlocks due to process variability during startup and shutdown	41	– SS Condition and higher process variability – Safety
3	Intermittent venting of isolated sections of the transport system due to flow balancing issues (higher than usual variability in flows from sub-systems)	35	– SS Condition and higher flow variability – Safety
4	Purge requirement of concentrated NCG line before pulp mill start-up (to prevent air from entering LVHC system)	25	– SS Condition – Safety
5	Transient venting of LVHC and HVLC sources due to slow "warm up" of boiler (low process steam requirements)	24	– SS Condition resulting in loss of permissives – Safety

1 above occurs near process equipment and stems from unusual variability in flows from process equipment during SS conditions. #2 may be temperature, pressure, and flow interlocks in the transport system that cannot be resolved due to unusual variability that exists during SS conditions. Issues due to flow balancing were also identified as being prevalent

during normal operation. While # 3 above may have the same end-result (the venting episode), the trigger is once again unusual process variability, germane to SS conditions. #4 is again a distinct SS condition that is encountered during a cold startup (when the purge requirement has to be satisfied).

In addition to the five SS scenarios identified above, 20+ facilities identified additional distinct conditions, from startup and shutdown periods, that cause intermittent venting of LVHC, HVLC, and SOG systems:

1. Transient venting due to combustion device instability on startup
2. SOG venting during steam stripper startup due to high pressure conditions which are the result of temperature fluctuations in the steam stripper reflux condenser
3. Tramp air purge from evaporators until vacuum is achieved
4. Venting due to high moisture caused by reduced flows and low system temperatures
5. Venting of HVLC sources due to "warm up" of thermal oxidizer
6. Evacuating air from storage vessels to prevent air ingression into LVHC system
7. Evaporator liquor carryover causing foaming and flame arrestor plugging
8. False instrumentation indications (causing safety vents to open) during switching between primary and back-up mill power supplies
9. Boilers not achieving the temperature needed to satisfy NCG burning permissives
10. Evaporator hotwell venting before vacuum is established
11. Transient venting from blow heat accumulator due to air ingression during a cold start-up. Steam purge used for keeping the accumulator “hot” is sometimes unsuccessful.

The above SS conditions and the associated increased levels of variability result in the tripping of interlocks and venting in LVHC, HVLC, and SOG systems. In addition to SS conditions in the steam stripper itself (# 2 above), any variability in steaming rates, steam availability, and condensate collection during SS conditions can also cause increased levels of operational variability in the steam stripper and lead to intermittent venting of SOGs. Again, the primary reason for venting is safety and system integrity.

KEY TAKEAWAYS ON INTERMITTENT VENTING EVENTS DURING STARTUP AND SHUTDOWN

Survey responses have identified several distinct SS conditions that trigger intermittent venting events. ***While the venting episode itself may be no different from a venting episode that occurs during routine or normal operation, the triggering conditions are unique SS conditions. Some of these events are caused by process variability, which in many cases exceeds the variability observed during normal operation.***

In the preamble to the RTR rule proposal, EPA has stated there was no information in the record indicating that operations (and attendant emissions) during startup and shutdown

conditions would differ from those during normal operation. However, the information obtained from this survey clearly indicates that SS conditions are not similar to normal operations, as it pertains to NCG and SOG control systems. Therefore, further consideration of startup and shutdown conditions is necessary.

3. Facilities are able to distinguish between routine operating periods and startup/shutdown (SS) periods. Survey results indicate that majority of facilities use threshold parameters to differentiate normal operating periods from startup and shutdown (SS) periods. Others have defined specific actions that are required to be carried out in order to startup or shutdown a piece of equipment or process.

EPA had requested specific information on how facilities differentiate venting episodes that occur during normal operation from those that occur during SS periods. This question was posed in the survey and the responses are discussed in detail below. Facilities have defined multiple threshold parameters to differentiate SS events from normal operation. More information on the threshold parameters used for LVHC systems, HVLC systems, and combustion devices are provided below.[15]

LVHC Systems

The following four parameters were most frequently identified by facilities as "threshold parameters" for differentiating normal operation from SS periods in LVHC systems.

#	Parameter	Facilities Identifying this Parameter
1	Steam flow to digesters	42
2	Flow and Temperature of weak black liquor feed to evaporators	34
3	Steam flow to evaporators	42
4	Total LVHC system Pressure or Flow	23

In addition to the threshold parameters identified above, 40+ facilities have identified additional operating parameters that are used to differentiate normal operating conditions from SS conditions. These include:

[15] It should be noted that, as with NCG systems during normal operations, mills have continued to improve their practices over the past dozen years to minimize venting during SS events. As the understanding of these practices has evolved, along with guidance from EPA and the states, in some cases the criteria mills have used for characterizing a condition as related to SS, normal operations, or malfunctions have evolved as well. The following attempts to provide a snapshot of current practices. In some cases, the criteria for distinguishing SS, M, and normal operations may be spelled out in state regulations or as guidance in Title V permits and related documents, but often the criteria are less rigid or explicitly specified as that.

- Flow of strong black liquor product from evaporators - foul condensate conductivity < 800 µmhos/cm AND combined condensate conductivity < 1,000 µmhos/cm
- Blow valve and relief valve opening
- Chip feed to digester (feeder rpm threshold)
- Digester steaming and blow heat system online. SS condition continues for at least 2 digester blows to blow heat accumulator system
- Steam flow plus pressure threshold at evaporator set (LVHC for evaporators
- Control device (boiler) operating and meeting permissives
- Flow of weak black liquor from digesters
- Chip feed to steaming vessel
- Product liquor flow valve open and water valve to evaporators closed
- Vacuum threshold in evaporator set
- Steam flow to liquor concentrators
- Final effect evaporator and surface condenser condensate conductivity

Stripper Off-Gas (SOG) Systems

The following four parameters were most frequently identified by facilities as "threshold parameters" for differentiating normal operating periods from SS periods associated with steam strippers.

#	Parameter	Facilities Identifying this Parameter
1	Condensate flow to steam stripper	35
2	Steam flow to steam stripper	27
3	SOG flow and/or other SOG parameters	13
4	Other (please specify)	14

In addition to the threshold parameters identified above, 14 facilities have identified additional operating parameters that are used to differentiate normal operation from SS conditions. These include:

- Having both condensate flow and steam to stripper begins the Startup period. Having sufficient SOG flow to continuously meet permissives for at least 30 min ends the startup period
- Control device (boiler) operating and meeting permissives
- Condensate stripper feed temperature
- Evaporator foul condensate flow
- Steam-to-condensate ratio

HVLC Systems

The following three parameters were most frequently identified by facilities as "threshold parameters" for differentiating normal operating periods from SS periods in HVLC systems.

#	Parameter	Facilities Identifying this Parameter
1	Stock flow to Brownstock washers (BSW)	30
2	Total HVLC gas flow from BSWs	15
3	Total system flow	14

In addition to the threshold parameters identified above, 15 facilities have identified additional operating parameters that are used to differentiate normal operation from SS conditions. These include:

- Steam flow to digesters
- Control device (recovery boiler) operating and meeting permissives
- Flow of weak black liquor from digesters
- Chip feed to steaming vessel
- Stock flow or pump amperage indicating oxygen delignification system operational
- Power to HVLC fan on
- Stock flow to knotter system
- Steam to the chip bin (chip bin goes to LVHC system in continuous digester)
- Meeting boiler permissives

Combustion Devices

The following three parameters were most frequently identified by facilities as "threshold parameters" for differentiating normal operating periods from SS periods in combustion devices.

#	Parameter	Facilities Identifying this Parameter
1	Primary and/or auxiliary fuel feed rate	35
2	Steam generation rate	26
3	Combustion air feed rate	11

In addition to the threshold parameters identified above, ~30 facilities have identified additional operating parameters that are used to differentiate normal operation from SS conditions. These include:

- Flame detection
- Combustion temperature and presence of gases (SS irrelevant if gases are diverted to alternative device or NCG sources are down)
- Mud flow to pre-coat filter or vacuum in pre-coat filter
- ID fan damper position
- Recovery furnace temperature
- Oxygen content in flue gas
- For a cold startup, lime kiln operating at a stable rate not less than 300 gpm of lime mud, incineration interlocks are met, and the manual switch is in the "Accept" mode – lime mud flow threshold dependent on number of sources collected
- For power boilers - a minimum steaming rate of 120000 lb/hr. Steam pressure > 1200 psig
- Steam flow to ejectors and permissives satisfied to burn NCG gases
- Combustion temperature
- NCG flow to thermal oxidizer
- Continuous parameter monitoring systems fully operational prior to introduction of pollutants to combustion device
- Flame safety system operational and all permissives met
- Minimum flame temperature
- Thermal oxidizer temperature
- Scrubber pH and flow rate, and
- Meeting boiler permissives

Twelve of the 81 facilities reported using a pre-defined set of specific actions to differentiate between SS conditions and normal operation. These specific actions needed to be carried out successfully in order for a startup or shutdown of a piece of equipment or process to be completed. The completion of this set of actions was subsequently used as a benchmark to differentiate the SS condition from normal operating conditions.

KEY TAKEAWAYS ON DIFFERENTIATING STARTUP AND SHUTDOWN EVENTS FROM NORMAL OPERATIONS

The majority of the facilities use threshold parameters to differentiate normal operating periods from SS periods. There is considerable variation from mill to mill, based on individual mill configuration and operating practices. Survey responses provide a better understanding of the types of threshold parameters used by facilities to differentiate between these two periods.

4. Malfunctions can also result in intermittent venting episodes. Survey responses suggest that venting episodes related to malfunctions fall into four categories, viz.; (a) those related to process equipment, (b) those related to the thermal destruction device, (c) those related to equipment in the transport system including sensors, gas conditioning equipment, and fiber/liquor separation equipment, and (d) those driven by uncontrollable events. Survey responses indicate that events in all four categories were equally prevalent.

The industry survey has provided information on the above four categories of events. More details on the number of facilities responding about malfunctions are provided below:

Category	Source and Type of Malfunction	Response
Process	Malfunctioning process equipment (control valves, blow heat accumulator circulation pumps, liquor heaters, etc.)	60
Transport Equipment	Malfunctioning collection and transport system equipment (pumps, fans, steam ejectors, flame arrestors, etc.)	62
Transport Equipment	Malfunctioning foam breakers that cannot be repaired "on-the fly" (causing excessive foam carryover)	14
Transport Equipment	Malfunctioning sensors (Pressure relief valves, temperature / flow / pH / pressure sensors, etc.) - System cannot be operated without fixing these devices	64
Control Device	Incineration device(s) unavailable due to burner plugging, flame-outs, tube leaks, or other major issues	60
Control Device	Malfunctioning control device equipment (condensate collection pumps, scrubber ID fans, ESP plates, etc.)	53
Uncontrollable Events	Loss of power, loss of instrument air, loss of water supply, etc.	66

Facilities have identified additional examples that include:

Category	Source or Type of Malfunction
Process	Bark screw malfunction (malfunctioning controller)
Process	Seal pot water flow interruptions
Process	Unusual pressure surge due to a process malfunction causing rupture disc to fail, P/V relief to lift, or loop seals to blow out.
Process	Foaming, level control issues in stripper caused by black liquor carryover or other contamination in the condensate feed
Process	Air entrainment in blow heat system during system cool-down during lower throughput periods, over-pressurization, blown loop seals and/or P/V relief valves
Transport Equipment	Fan, ducting, demister, flame arrestor, dampers, or any other associated in-line equipment plugged or plugging
Transport Equipment	Malfunction of process control systems/distributed control systems (bad I/O card, power surge, etc.)
Transport Equipment	HVLC fan malfunction (broken shaft, motor failure, belt failure, etc.)
Uncontrollable events	Natural gas supply interruption due to internal or external line failure (required for thermal oxidizer and lime kiln)

A closer examination of the most frequently identified malfunction triggers of venting events would suggest that it is inappropriate to combine these four categories of events into a single bucket. The following characteristics are worth additional consideration:

- Malfunctions of isolated equipment and sensors in the transport system are expected to be less disruptive to overall NCG system operation than are malfunctions of process equipment and control devices. Sub-systems can be effectively isolated while the rest of the system remains in operation.
- A subset of transport system equipment problems are momentary and could stem from inherent process variability (plugging of condensate drains, foam carryover, malfunctioning steam ejectors etc.). These may recur and hence are not reasonably preventable through maintenance or corrective actions.
- Malfunctions of process equipment or combustion devices, on the other hand, are of a different level of significance than the ones described above.

A closer examination of these different categories of malfunctions is therefore justified, specifically from the stand-points of (a) what triggers them, (b) whether they are infrequent and reasonably preventable and (c) whether they can be classified as malfunctions, as defined by the rule, with the option to avail of affirmative defense. A broad-based classification of malfunctions, as it pertains to the NCG collection and transport system, has the potential to significantly increase the regulatory burden for facilities.

5. Steam stripper downtimes do not reflect "no HAP control" scenarios. Facilities routinely route their condensates to biological wastewater treatment systems during steam stripper downtime periods. Biological treatment systems have been demonstrated to achieve high levels of treatment for methanol and major non-methanol HAPs. They are currently being employed by facilities to demonstrate compliance with condensate treatment requirements.

The following information applies to the 33 facilities that reported employing steam strippers for demonstrating compliance with condensate treatment requirements:

- All 33 (100%) of the facilities continue to collect condensates in the condensate tank during temporary outages. Temporary outages or downtimes may be the result of momentary unavailability of the combustion devices (due to momentary loss of permissives etc.), or temporary operational issues with steam availability, etc.
- The following practices apply to longer downtimes of the steam stripper
    - 20 out of the 33 facilities route condensates through the primary clarifier to biological treatment systems
    - 6 facilities bypass the primary clarifier and directly route condensates to the biological wastewater treatment system
    - Remainder of the facilities reported utilizing different condensate reuse, recycling, or re-routing practices.
    - 3 of the facilities that also operate HVLC systems reported routing their condensates back to liquor storage tanks (the tanks are air-swept and collected as part of the HVLC system).

Survey responses indicate that the vast majority of facilities continue to achieve HAP treatment during steam stripper outages/downtimes. Downtime periods in the steam stripper do not mean that the facility is achieving zero HAP control from condensate treatment. Facilities routing condensates to biological treatment systems are expected to achieve greater than 80% methanol removal.

6. Compilation of applicable state-specific recording, reporting, and other requirements pertaining to NCG venting events

In discussions leading up to the distribution of the NCASI survey, OAQPS requested specific information on restrictions, if any, imposed by States on the duration of single NCG venting episodes. This request was in response to comments filed by The State of Maine Department of Environmental Protection (Maine DEP) on the proposed elimination of the venting allowances. In its comments, Maine DEP urged EPA to maintain the 1% and 4% venting allowances. The agency indicated that the state TRS rule (06-096 CMR Ch. 124) limits any single LVHC system vent to 40 minutes. Maine DEP also indicated that the 40 minute individual vent limit imposed as part of the TRS rule, in conjunction with venting allowances, was effective in minimizing the total duration of venting.

The agency also acknowledges the fact that intermittent NCG venting episodes are inevitable given the complexity of the system and the need to deliver flammable NCG gases safely to combustion devices. A compilation of alternate rule or other applicable State requirements pertaining to the recording, reporting, and classifying of NCG venting episodes, as reported by facilities responding to this survey, is provided below.

State	Alternate State rule OR operating permit threshold for recording vents (MINUTES)		Threshold above which a SINGLE VENTING EVENT is further investigated and recorded as a MALFUNCTION (MINUTES)		State/Operating permit that limits individual venting events from exceeding a specific threshold (MINUTES)	
	LVHC/SOG	HVLC	LVHC/SOG	HVLC	LVHC/SOG	HVLC
AL			60	60	240	240
GA	5	5	30	30		
MS			240			
AR	1		30		30	
SC			60	60		
TN			15			
NC			240	240		
VA			60	60		
WI			120	480		
ME	1	1	15	240	40	
OR			60		60	
WA	1				600[1]	

[1] 600 minutes of total LVHC venting allowed per month

As indicated in the Table, a handful of states impose limits on the duration of individual LVHC system vents. Arkansas, Oregon, and Alabama impose limits of 30, 60, and 240 minutes for any individual vent from the LVHC system. The state of Washington imposes a cumulative monthly limit of 600 minutes for vents from the LVHC system.

In addition to limiting the duration of individual vents, several states also impose duration limits above which any single venting event needs to be further investigated to identify the root cause and prevent recurrence. This duration limit varied from State to State and ranged from 15 minutes to 240 minutes.

Attachment 2

Attachment A, NCASI Non Condensible Gas Venting Survey Questionnaire, May 2012

GENERAL QUESTIONS

Facility Details _ Company, City, and State

Describe your facility's NCG Collection Practices (please select all that apply)

- [ ] Low Volume High Concentration (LVHC) System
- [ ] High Volume Low Concentration (HVLC) System
- [ ] Stripper-off-Gas (SOG) System
- [ ] SOG collected and treated in dedicated system

Incineration Points for LVHC System

Primary Incineration Point

Secondary Incineration Point

Tertiary Incineration Point

Incineration Points for SOG System

Primary Incineration Point

Secondary Incineration Point

Tertiary Incineration Point

Incineration Points for HVLC System

Primary Incineration Point

Secondary Incineration Point

Tertiary Incineration Point

QUESTIONS ON VENTING EVENTS

LVHC System Venting Events

From the list below., RANK the TOP SIX causes of venting events (NOT including SSM). Rank the events "1" thru "6".
In the absence of information to RANK these events, please SELECT the TOP SIX by entering an "x" in the corresponding boxes.

		By # of Occurrences	By Total Duration
Low chip level in the Chip Bin			
Flow balancing issues			
Pressure or Temperature Parameters on Process Equipment outside normal operating ranges			
Flow Interlocks at or near Process Equipment (low flow to secondary blow heat condenser, etc.)			
Pressure, Temperature, Flow Interlocks at the Steam Stripper			
Pressure or Temperature Interlocks in Gas Transport System (overall system pressure, frequent digester blows, process variability, etc)			
Temperature interlocks in Gas Conditioning System (condenser exit temp., cooling water temperature, etc.)			
Flow Interlocks in Gas Transport System (overall system flow, cooling water flow, etc.)			
Steam Interlocks in Gas Transport System (Steam flow in Ejectors)			
Primary combustion device not available (low steam rate, loss of burner permissive, flame-out etc.)			
Back-up combustion device also unavailable			
Switching between incineration points			
Other **(please specify)**			

Describe your facility's MACT I Phase 2 compliance approach [please select all that apply]

- HVLC Collection and Incineration
- Clean Condensate Alternative (CCA)
- Approved Alternative Approach

HVLC System Venting Events

From the list below., RANK the TOP SIX causes of venting events (NOT including SSM). Rank the events "1" thru "6".
In the absence of information to RANK these events, please SELECT the TOP SIX by entering an "x" in the corresponding boxes.

		By # of Occurrences	By Total Duration
Low chip levels in chip bin			
Flow balancing issues			
Pressure or Temperature parameters on Process Equipment outside normal operating ranges			
Flow Interlocks in Isolated Process Equipment (washers, chip bins, etc.)			
Temperature interlocks in Gas Conditioning System (condenser exit temp., cooling water temperature, etc.)			
Pressure or Temperature Interlocks in Gas Transport System (condenser exit temp, system pressure, etc.)			
Flow Interlocks in Gas Transport System (overall system flow, make-up air flow, etc.)			
Steam Interlocks in Gas Transport System (Steam flow in Ejectors)			
Primary combustion device not available (low steam rate, loss of burner permissive, flame-out etc.)			
Backup combustion device (if applicable) not ready			
No Backup system _ Primary combustion device outage for maintenance			
Switching between incineration points			
Other **(please specify)**			

Total Number and Duration (in MINUTES) of LVHC Venting Events in FIRST reporting period of 2011 (January - June)

Please select alternative reporting period (2009 or 2010) if facility had unusual incidents in 2011

- Total number (SSM + non-SSM) of Venting events
- Total duration of venting events (SSM + non-SSM) in MINUTES
- Number of non-SSM venting events
- Duration of non-SSM events in MINUTES (counts towards the 1% excess emissions limit)
- Enter YYYY of alternative reporting period if used

Total Number and Duration (in Minutes) of LVHC Venting Events in SECOND reporting period of 2011 (July - December)

Please select alternative reporting period (2009 or 2010) if facility had unusual incidents in 2011

- Total number (SSM + non-SSM) of Venting events
- Total duration of venting events (SSM + non-SSM) in MINUTES
- Number of non-SSM venting events
- Duration of non-SSM events in MINUTES (counts towards the 1% excess emissions limit)
- Enter YYYY of alternate reporting period if used

Total Number and Duration (in MINUTES) of HVLC Venting Events in FIRST reporting period of 2011 (Jan - June)

Please select alternative reporting period (2009 or 2010) if facility had unusual incidents in 2011

- Total number (SSM + non-SSM) of Venting events
- Total duration of venting events (SSM + non-SSM) in MINUTES
- Number of non-SSM venting events
- Duration of non-SSM events in MINUTES (counts towards the 4% excess emissions limit)
- Enter YYYY of alternate reporting period if used

Total Number and Duration (in MINUTES) of HVLC Venting Events in SECOND reporting period of 2011 (July - December)

Clarification: **Please select alternative reporting period (2009 or 2010) if facility had unusual incidents in 2011**

- Total number (SSM + non-SSM) of Venting events
- Total duration of venting events (SSM + non-SSM) in MINUTES
- Number of non-SSM venting events
- Duration of non-SSM events in MINUTES (counts towards the 4% excess emissions limit)
- Enter YYYY of alternate reporting period if used

Defining Startup, Shutdown, and Malfunction (SSM)

Identify all applicable Threshold parameters used to define Start-up/Shutdown (SS) conditions in the LVHC system [please select all that apply]

- Steam flow to digesters
- Flow and Temperature of weak black liquor feed to evaporators
- Steam flow to evaporators
- Total LVHC system Pressure or Flow
- Other **(Please specify)**
- Other **(please specify)**

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Threshold parameters used to define Start-up/Shutdown (SS) conditions in the Steam Stripper and SOG System [please select all that apply]

- Condensate flow to steam stripper
- Steam flow to steam stripper
- SOG flow and/or other SOG parameters
- Other **(please specify)**
- Other **(Please specify)**

Threshold parameters used to define Start-up/Shutdown (SS) conditions in the HVLC System [please select all that apply]

- Stock flow to Brownstock washers (BSW)
- Total HVLC gas flow from BSWs
- Total system flow
- Other **(please specify)**
- Other **(Please specify)**

Threshold parameters and conditions used to define Start-up/Shutdown (SS) conditions in the Incineration Device(s) [please select all that apply]

- Primary AND/OR Auxiliary fuel feed rate
- Steam generation rate
- Combustion air feed rate
- Other **(please specify)**
- Other **(Please specify)**

Examples of Venting events that could occur during Start-up and Shutdown periods (check all that apply)

- Purge requirement of concentrated NCG line before pulp mill start-up (to prevent air from entering LVHC system)
- Transient venting of LVHC and HVLC sources due to slow "warm up" of boiler (low process steam requirements)
- Isolated venting of process equipment before reaching steady state
- Intermittent venting of isolated sections of the transport system due to flow balancing issues
- Inability to resolve interlocks due to process variability during start-up and shutdown
- Other **(Please specify)**

Defining a MALFUNCTION _ Categories of Malfunctions in NCG collection and treatment [please select all that apply]

- Malfunctioning process equipment (control valves,accumulator circulation pumps, liquor heaters, etc.)
- Malfunctioning collection and transport system equipment (pumps, fans, steam ejectors, flame arrestors etc.)
- Malfunctioning foam breakers that cannot be repaired "on-the fly" (causing excessive foam carryover)
- Malfunctioning sensors (Pressure relief valves, temperature / flow / pH / pressure sensors etc.) - System cannot be operated without fixing these devices
- Incineration device(s) unavailable due to burner plugging, flame-outs, tube leaks OR other major issues
- Malfunctioning control device equipment (condensate collection pumps, scrubber ID fans, ESP plates, etc.)
- Loss of power, loss of instrument air, loss of water supply, etc.
- Other **(Please specify)**
- Other **(please specify)**
- Other **(please specify)**
- Other **(please specify)**

Steam Stripper Practices

Does your facility operate a Steam Stripper for complying with the condensate treatment requirements under MACT?

- Yes
- No

Condensate collection and treatment practices during Steam Stripper downtime periods (check all that apply)

- Continue collecting condensates in condensate tank for TEMPORARY OUTAGES
- Route condensates through primary clarifier and biological wastewater treatment system FOR LONGER OUTAGES and DURING MAINTENANCE DOWNTIME
- Bypass primary clarifier and route condensates to biological wastewater treatment system FOR LONGER OUTAGES and DURING MAINTENANCE DOWNTIME
- Other **(please specify)**

Recording / Reporting Thresholds for Venting Events

Recording and Reporting of Venting events (if these questions are not applicable for your facility, enter "X" in Not Applicable)

	LVHC / SOG System	HVLC System	Not Applicable
RECORDING THRESHOLD - What is the minimum threshold (in MINUTES) for recording venting events at your facility?			
Is there a NESHAP, an alternate State rule, OR operating permit threshold (in MINUTES) for recording vents at your facility?			
Is there a Threshold (in MINUTES) above which your State requires any SINGLE VENTING EVENT to be further investigated and recorded as a MALFUNCTION?			
Does your State/Operating permit LIMIT individual venting events from exceeding a specific threshold (in MINUTES)? e.g., the state of Maine limits individual venting events from exceeding 40minutes			

Please Add any Additional Comments OR Clarifications in this Section.

Attachment 3

Attachment B, Recommended Good Practice Thermal Oxidation of Waste Streams in Black Liquor Recovery Boilers, The Black Liquor Recovery Boiler Advisory Committee (BLRBAC), February, 2012

RECOMMENDED GOOD PRACTICE

THERMAL OXIDATION OF WASTE STREAMS IN BLACK LIQUOR RECOVERY BOILERS

THE BLACK LIQUOR RECOVERY BOILER ADVISORY COMMITTEE

February 2012

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CHANGES

February 2012

"Notice of Disclaimer of Liability" has been added to page 2.

For a summary of prior changes to this document refer to Appendix A, Document Revision History.

CHAPTER 1 INTRODUCTION

The black liquor recovery boiler presents problems of operation and safety that far exceed those of the conventional power boiler or other forms of combustion equipment that can be used for the thermal oxidation of waste streams. The recovery boiler is primarily a chemical recovery process unit in which organic materials in the black liquor are burned while the oxidized sulfur compounds of sodium and potassium are reduced and drained as molten smelt from the furnace bottom. At the same time, the heat released is used for generation of steam for power and process.

This document is intended to address concerns of the industry relating to safe thermal oxidation of waste streams in recovery boilers. "Waste streams" for this document are produced in the pulping process. The major waste stream is noncondensible gases (NCG), which are gases that contain reduced sulfur compounds from the digester and evaporator operations and are a source of odor. The following list is representative of the pulping process waste streams that are addressed:

- Dilute Noncondensible Gas (DNCG)
- Concentrated Noncondensible Gas (CNCG)
- Stripper Off Gas (SOG)
- Chip Bin Noncondensible Gas (CBNCG)
- Dissolving Tank Vent Gas (DTVG)
- Soap
- Methanol
- Turpentine
- Tall Oil
- Spent Acid
- Secondary Sludge

The principal process benefit to thermally oxidizing these streams in the recovery furnace is that the sulfur content of the streams can be retained within the process rather than be discharged to the surroundings. While most of the heat for the chemical recovery process is from the burning of black liquor, the waste streams may introduce additional heat and moisture into the furnace.

The thermal oxidation of waste streams in the recovery boiler increases the complexity of the operation as well as the potential safety risks in the recovery boiler building. This *Recommended Good Practice for the Thermal Oxidation of Waste Streams in Black Liquor Recovery Boilers* should be reviewed regarding equipment, safety systems and operating procedures for the design and operation of waste stream systems installed on the recovery boiler. Information included in this Good Practice can assist in minimizing the risk for the operating company that chooses to thermally oxidize any of these streams in the recovery boiler.

The complexity of the chemical recovery process and the severe environment combine to present a formidable challenge to operators of recovery boilers. The difficulty of the

operation is increased if the waste streams are thermally oxidized in the recovery furnace. Further, there is a potential to degrade the environment in the recovery boiler building with the introduction of waste streams. In most cases, the recovery boiler operators must depend on the thoroughness of their training, their own personal senses and reactions, and instrumentation to aid in safe operation. Many times the operators are forced to evaluate a situation rapidly, and it is hoped, correctly, without having all of the facts. The burden on the recovery boiler operator is truly great and the industry has realized that they must have help, guidance and proper tools to promote safety and boiler availability. These take on increased importance in a mill that introduces waste streams into the recovery boiler.

The Waste Streams Subcommittee was formed in 1997 to evaluate the experience with thermal oxidation of liquid and gaseous waste streams in the recovery boiler. The industry experience level had evolved at that time with a substantial number of recovery boilers thermally oxidizing both DNCG and CNCG. The considerable experience with burning NCG in other control devices, such as bark boilers and lime kilns, had resulted in substantial advances in technology and operation of collections systems and combustion of NCG. After evaluation of the industry experience, the Waste Streams Subcommittee determined with the agreement of the Executive Committee that there was justification to develop recommended BLRBAC guidelines for using the recovery boiler as an emission control device. The result is this *Recommended Good Practice for Thermal Oxidation of Waste Streams in Black Liquor Recovery Boilers*.

The following publications are additional references concerning thermal oxidation of waste streams in recovery boilers, and they were part of the foundation upon which this document was prepared.

Soda House Committee of the Swedish Steam Users Association:

- *Guidelines Regarding Equipment and Safety Systems for Destruction of Concentrated NCG, Methanol and Turpentine in Recovery Boilers*, Publication No. B16.
- *Destruction by Means of Combustion of LVHC Gases, Methanol and Turpentine in Black Liquor Recovery Boilers*, Publication No. C9.
- *Recommendations Concerning Equipment and Safety Systems for Oil and Gas Firing in Black Liquor Recovery Boilers*, Publication No. B13.

Finnish Recovery Boiler Association:

- *Recommended Procedure for Incineration of Noncondensible Gases*.

FM Global:

- *Property Loss Prevention Data Sheet 6-21, Chemical Recovery Boilers*.
- *Property Loss Prevention Data Sheet 6-13, Waste Fuel-Fired Boilers*.

CHAPTER 2 DEFINITIONS AND ABBREVIATIONS

Terms that are used in the *Recommended Good Practice* are defined. Definitions where applicable are used as they appear in the Final Pulp and Paper Cluster Rule (63 FR 18504-18751).

Chip bin: A vessel used for the purpose of preheating or pretreating wood chips prior to the digester, using flash steam from the digester or live steam.

Chip Bin Non-Condensible Gas (CBNCG) – Gas containing a concentration of sulfur compounds and/or turpentine, methanol and other hydrocarbons that is generated from the pre-steaming of chips prior to entering the Digester. As a consequence, this source of NCG will normally be high in oxygen content and can, under upset Chip Bin operation, exceed 100% LEL.

Control device or **combustion device:** An individual unit of equipment, including but not limited to, a thermal oxidizer, lime kiln, recovery furnace, process heater, or boiler, used for the thermal oxidation of organic hazardous air pollutant vapors or combustible liquids extracted in the process, such as, turpentine or methanol. These Guidelines will only take into consideration the recovery furnace as the control device.

Concentrated noncondensible gas (CNCG): Gas containing a concentration of sulfur compounds and/or turpentine, methanol and other hydrocarbons that is ideally above the upper explosion limit (UEL), frequently referred to as Low Volume, High Concentration gases (LVHC). The CNCG definition is exclusive of volume.

CNCG system: The gas collection and transport system used to convey gases from the CNCG sources to the recovery boiler, or other combustion device. Sources are closed systems (no air intrusion) and may include: digesters, turpentine recovery, evaporators, and steam stripper systems.

Dilute noncondensible gas (DNCG): Gas containing a concentration of sulfur compounds that is below the lower explosion limit (LEL), frequently referred to as High Volume, Low Concentration Gases (HVLC). The DNCG definition is exclusive of volume.

DNCG system: The gas collection and transport system used to convey gases from the DNCG system to the recovery boiler, or other combustion device. Sources may include pulp washing, knotter, screen, decker, and oxygen delignification systems, black liquor storage tanks, and boiler house chemical ash mix tank.

Dissolving Tank Vent Gas (DTVG): The exhaust from the dissolving tank, considered a DNCG. This gas is primarily air and steam with particulate, green liquor droplets, and other compounds.

Dissolving Tank Vent Gas System: The gas collection, cleanup and transport system used to convey gases from the dissolving tank to the furnace.

ESP: emergency shutdown procedure (ESP) - A shutdown procedure that must be performed whenever any amount of water is known or suspected to be entering the furnace and cannot be stopped immediately.

Flame propagation: The velocity at which a flame will travel through a flammable vapor.

Flammable: Refers to a fuel, which could be gaseous, liquid, or solid, that is explosive, easy to ignite and/or burns quickly.

Flash Steam: Steam derived from the flashing of hot, pressurized liquor extracted from the digester. Flash steam is used for pre-steaming chips in the Digester Steaming Vessel and in the Chip Bin and is rich in turpentine, methanol, and TRS.

High Volume, Low Concentration (HVLC): Another name for DNCG.

Lower Explosion Limit (LEL): A concentration by volume of a compound in air below which the mixture will not catch on fire. Also called Lower Flammability Limit (LFL).

Low volume, high concentration (LVHC): Another name for CNCG.

Maximum Continuous Rating (MCR): The maximum design/nameplate steaming rate or liquor firing rate for a recovery boiler.

Methanol (CH_30H): A by-product created during the pulping and bleaching process by the degradation of the methoxy groups on hemicellulose and lignin. Methanol is flammable and provides positive net Btu value. Methanol is water soluble and may be found in solution or as a vapor.

Noncondensible gas (NCG): Refers to the gases containing sulfur and/or organic compounds, i.e., CNCG, DCNG, and SOG. Some mills refer to NCG as TRS gases.

Recovery boiler building (or area): The boundary used within a mill to identify the areas around a recovery boiler that are affected by an ESP. Personnel are not to enter these areas until after an ESP is completed and entry is permitted.

Red oil: A mixture of terpenes and TRS compounds. “Red oil” is highly contaminated turpentine with a lower flash point and a higher sulfur content. For these guidelines, red oil should be treated as turpentine.

Secondary Sludge: The waste residue resulting from the biological treatment of wastewater.

Soap: A by-product formed during the pulping process by the reaction of alkali and fatty wood acids.

Spent Acid: The aqueous solution by-product from the acidulation of tall oil soap to tall oil, usually consisting primarily of sodium sulfate in water solution. ClO_2 spent acid is the effluent from a ClO_2 generator. The term "spent acid" is used to refer to both tall oil brine and ClO_2 spent acid.

SSV: Safety shutoff valve.

Stripper Off-Gas (SOG): Methanol, reduced sulfur gases and other volatiles removed by a steam stripping and distillation process from digester and condenser condensates (this definition deviates from the Cluster Rule definition).

Tall Oil: A mixture of fatty acids, rosin and neutral materials resulting from the acidulation of soap skimmings from kraft black liquor.

Total reduced sulfur (TRS): The total sulfur compounds existing in gaseous sulfate emissions, condensate, and waste waters that are the result of the reduction of sulfur by the pulping process. TRS typically includes hydrogen sulfide (H_2S), methyl mercaptan (CH_3SH), dimethyl sulfide (CH_3SCH_3), and dimethyl disulfide (CH_3SSCH_3).

Upper Explosion Limit (UEL): A concentration by volume of a compound in air above which the mixture will not catch on fire. Also called Upper Flammability Limit (UFL).

Waste Stream(s): For this document, the term "waste stream" refers <u>only</u> to byproducts of the pulping process.

CHAPTER 3 MAJOR CONSIDERATIONS

3.1 Introduction

This *Recommended Good Practice* describes some of the special considerations required for system design and operation of waste streams incineration in a kraft recovery boiler. This information is intended to provide guidelines for safe firing of NCGs and other kraft recovery process waste streams. It is not the intent of this document to design the systems.

3.2 Explosion

By definition, the DNCG are gases from those sources that are below the lower explosion limit (LEL). CNCG are gases from those sources that are generally above the upper explosion limit (UEL). During abnormal operating conditions, individual DNCG sources can be occasionally prone to have concentrations spike above the LEL, particularly gases generated from chip bins, digester blow tanks, washer foam tanks, and heavy black liquor storage tanks. Gas streams combined from several sources in a DNCG system require the system be designed to operate below the LEL to prevent potential explosive or flammable conditions from occurring. Air infiltration in a DNCG system serves to dilute the gases, lessening the potential for explosion.

CNCG and SOG are rendered non-flammable due to low oxygen content. The composition of SOG is typically a saturated vapor stream and explosion risk is low. The composition of CNCG is not always above the UEL. The risk of explosion occurs when gas composition changes occur, creating a situation where the stream drops below the UEL. Such changes in a CNCG system could be brought about due to an operational upset, system failure or air infiltration from leaking flanges, gaskets or valves on the vacuum section of the collection header.

The explosion limits of NCG constituents are listed in Table 1.

Table 1 Explosion Limits of NCG Constituents[1]

Constituent Gases	Lower Explosion Limit (LEL) % Volume in Air	Upper Explosion Limit (UEL) % Volume in Air
Turpentine (α-Pinene)	0.80	Not Established
Methanol (CH_3OH)	7.3	36
Methyl Mercaptan (CH_3SH)	3.9	21.8
Dimethyl Sulfide (CH_3SCH_3)	2.2	19.7
Dimethyl Disulfide (CH_3SSCH_3)	1.1	16.1

[1] U.S. Bureau of Mines, Bulletin No. 503

Burgess cites values of explosion limits that are equal or very close to the above values.[2] The author further indicates the generally accepted values for combined gases to be 2% for LEL and 50% for UEL, that is, gases are flammable over the range of 2 to 50% for all combustibles.

Due to the explosive nature of these NCG constituents, the DNCG, CNCG and SOG gas streams should be collected and transported in separate dedicated pipelines. Mixing of DNCG and CNCG could lead to combined stream with concentrations within the explosive range. Combining a SOG stream with other concentrated gases may produce two phase flows from the condensation of SOG constituents. Turpentine is the primary concern in this situation due to its very low explosion limit, and high flame propagation speed (505 fps). In comparison, the flame velocity of methanol (1.6 fps) and methyl mercaptan (1.8 fps) are much lower.[2]

The removal of condensate from NCG pipelines is critical to ensure safe operation. The design of a NCG transport system includes steam ejectors or fan, mist eliminators, sloped piping, low point drains, and condensate collection systems. The transport systems also incorporate line pressure sensors, rupture discs, emergency purge vents, temperature sensors, flow meters, flame arresters, and isolation valves. The recovery boiler burner management system must address key interlocks for safe firing of NCG including SSVs fully closed or open, scanner proving "no flame" for the continuous igniter (if required) and adequate furnace temperature proven by proxy of a steam flow minimum. The open or closed position of all SSVs should be confirmed by limit switches that provide a control room indication and initiate an alarm if improperly positioned.

A gas explosion within the recovery furnace or burn back into the NCG collection system are the greatest potential hazards. This could occur if a CNCG or SOG stream is introduced into a furnace that does not have a continuous igniter in service and adequate furnace temperature from the firing of auxiliary fuel and/or black liquor combustion, or if a DNCG stream being used as combustion air becomes concentrated above its LEL. Gas explosions could also take place in the gas handling system close to the recovery boiler. Explosions in the gas handling system could trigger a sequence of events leading too much more serious consequences.

The velocity of the waste gas stream entering the furnace should be above the flame propagation speed to reduce the opportunity for burn back. Flame propagation speeds for gas streams containing turpentine are very high and this requirement is virtually impossible to meet if the turpentine is not removed from the gas stream prior to incineration. Contamination of the gas stream with turpentine is the most frequent cause of explosions in DNCG handling systems.

Condensate formed in NCG collection and transport systems provides the potential route for water to enter the furnace cavity. Waste gas streams are frequently collected at saturated conditions and steam ejectors are recommended for use as prime movers in the gas collection and transport systems. The steam brought into the system with an ejector is

[2] Burgess, T.L., *Noncondesible Gases*, Chemical Recovery in the Alkaline Pulping Process, Chapter 3

used to purge the piping and warm the line prior to introducing NCG's, and also to act as a "flame arrestor" of sorts while reducing the percent oxygen concentration in the stream during normal operation. It is possible to have large aqueous streams, such as digester extraction liquor or foam formed in the evaporator and carried through a condensate stripper, back up into the waste gas collection system.

Possible modes for water entry into the furnace when burning waste streams include:

1. Flooding the gas stream with liquid due to inadequate sloping of the ductwork and inadequate or malfunctioning drains in the gas transport system.
2. Condensation from high-moisture gas in cold ductwork or inside the boiler during start-up, boiler trips or blackouts.
3. An explosion in the gas handling system close to the boiler could damage boiler pressure parts and result in a water leak into the furnace.

The Waste Streams Subcommittee emphasizes the importance during the design of the NCG systems to carefully analyze all automatic actions that can occur during upsets or other upset conditions at the NCG source or at the boiler and/or transport system. This analysis should include start-up, shutdown and upset conditions of the system, and consider all sources, such as, evaporator, condensate stripper and digester, and the boiler.

Liquid waste streams blended with black liquor and liquid waste streams fired in dedicated burners do not, in themselves, represent an explosion hazard during transport to the recovery furnace. There are design considerations important to both and these are described in later chapters.

3.3 Turpentine Hazards

The most prevalent cause of fires and explosions in NCG collection, transport and combustion systems is the presence of terpenes (turpentine vapor) in the gas stream in concentrations that result in explosive mixtures. These can be easily ignited from a number of sources such as static electricity, an electrical spark, or reaching the auto-ignition temperature of the α-pinene (487°F). The upper and lower explosion limits for turpentine vapor are not very well defined, but the explosion range is known to be very wide due to the variability in turpentine composition.

3.4 Emergency Shutdown Procedure (ESP)

The protocol for the recovery boiler operation is that an ESP shall result in the **immediate** diversion of all fuels from the furnace. This includes any waste streams which can be fired in the recovery boiler. DNCG, CNCG and SOG, or other waste streams entering the recovery furnace, must be automatically diverted upon initiation of an Emergency Shutdown Procedure (ESP).

3.5 Corrosion

In some instances, the introduction of DNCGs into existing air systems has led to corrosion of the air ducts. Proper design of the collection and transport system will minimize the potential for corrosion. Use of a gas cooler with DNCG will remove water vapor. If a cooler is used, a heater should be installed (after the mist eliminator) to reheat the DNCG. Heating should be a part of the system regardless of whether the DNCG is injected into the furnace through ports or mixed with combustion air in the ducts. The transport system should be designed to deliver the gas at approximately 50% or less relative humidity and at least 150°F. The temperature should be higher than the dew point of the gas stream.

Proper material selection is critical for avoiding corrosion. An additional safety measure is installation of corrosion coupons to monitor corrosion and predict the remaining life of a given system. At a minimum, all components of the transport and combustion system should be inspected regularly.

Thermal oxidation of liquid or gaseous waste streams could lead to higher SO_2 levels in the furnace and a greater potential for pressure part corrosion. Lower drum ("near drum") corrosion caused by acidic sulfates has been reported by a number of mills. Corrosion could lead to a boiler pressure part failure. In addition, any burners and/or flame arresters in the NCG system are very susceptible to corrosion and need to be inspected regularly. SO_2 in the flue gases leaving the recovery furnace must be maintained at a low level to minimize the potential for corrosion. An important consideration for thermal oxidation of liquid or gaseous waste streams in the recovery furnace is adequate black liquor concentration (typically over 70%) to provide furnace conditions that make it possible to control the SO_2 at the desirable low levels for corrosion and emissions control.

The Waste Streams Subcommittee is not aware of any boilers that have suffered pressure part corrosion due to admission of liquid or gaseous waste streams to the furnace.

3.6 The Effect of Sulfur Input and Solids Concentration on SO_2

The Cluster Rule (in North America) requires incineration of liquid or gaseous waste streams in a boiler by introducing the gases to the 'flame zone' so as to insure destruction of these gases via oxidation to sulfur dioxide (SO_2). Flame zone is not defined.

In a recovery boiler, the SO_2 produced in the thermal oxidation of black liquor is scrubbed by the alkali fume present in the upper furnace to form sodium sulfate (Na_2SO_4) which deposits on tube surfaces and is captured in the electrostatic precipitator. In this sense, recovery boiler chemistry provides a self-scrubbing mechanism for SO_2. The limiting factor for SO_2 scrubbing is the amount of alkali hydroxides, sodium and potassium, that are present in the furnace. In general, furnaces that burn hotter (those with higher black liquor solids) will volatilize more sodium and in turn have a higher sulfur capture efficiency. There are many cases reported in the literature of recovery boilers operating with low or no detectable SO_2.

The high sulfur capture efficiency is one of the factors that make incineration of liquid and gaseous waste streams in the recovery furnace an attractive alternative. The impact on emissions is less than other incineration devices (such as bark boilers or stand alone incinerators) and the sulfur is maintained within the liquor cycle. For example, if the mill is incinerating 500 lb/hr of sulfur from the waste stream compounds in a recovery boiler with a capture efficiency of 98%, 490 lb/hr of the sulfur would be recovered in the form of saltcake (equivalent to 10.3 tpd NaHS or 26.1 tpd Na_2SO_4).

Analysis of the ash from a recovery boiler can give an indication of its capacity to scrub additional sulfur. If the ash collected in the electrostatic precipitator contains sodium carbonate (Na_2CO_3), there is sodium available for scrubbing more sulfur in proportion to the Na_2CO_3 content. Investigations by the University of Toronto demonstrate that the black liquor solids concentration should be above 70% to assure sufficient Na_2CO_3 in the flue gas.[3] The data shows ash generally containing 8-10 mole percent carbonate [$CO_3/(Na_2 + K_2)$] when the black liquor is fired at 70% solids. This level of carbonate would, in most installations, be sufficient for sulfation of alkali hydroxides to provide complete SO_2 removal.

Most modern recovery boiler installations and an increasing number of the older units are firing black liquor at concentrations exceeding 70%. One of the most noticeable results of burning the liquor at the higher solids concentrations is that the SO_2 content of the flue gas is frequently negligible. This is particularly true in North America where sulfidity levels are commonly in the 25 to 30% range. For sulfidity levels on the order of 40%, such as those common in Nordic countries, even higher solids levels may be required to ensure a negligible concentration of SO_2 in the flue gas. Higher solids mean that less water is introduced into the furnace to absorb heat by evaporation, resulting in higher temperatures in the lower furnace. This results in an increased level of alkali (sodium and potassium) in the flue gas to react with the SO_2 that is also formed as a combustion product.

3.7 The Effect of SOG Input on NOx Emissions

The SOG stream from the stripper typically contains ammonia. The ammonia may be in sufficient concentration to cause the formation of NOx in the recovery furnace. One study indicates that approximately 20% of the nitrogen in the black liquor is removed during evaporation.[4] Most of this nitrogen ends up in the evaporator condensate. Subsequent stripping will remove the nitrogen from the condensate and it will ultimately be found in the SOG. The stripper supplier and the boiler manufacturer should be consulted to ascertain the effect on the boiler NOx emission, if any.

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[3] Tran, H., Villarroal, R., *Effect of CNCG Combustion on Recovery Boiler Performance and Precipitator Dust Composition*, unpublished paper, Annual Research Review Meeting, University of Toronto Pulp & Paper Centre, November 18-19, 1998.

[4] Kymalainen, M, Forssen, M, Hupa, M, *The Fate of Nitrogen in the Chemical Recovery Boiler Process in a Kraft Pulp Mill*, Proceedings of the International Chemical Recovery Conference, TAPPI Press 1998, p. 19-32.

3.8 Health Considerations

Liquid and gaseous waste steams contain hydrogen sulfide, as well as other reduced sulfur gases, and can be hazardous to human health.

The toxic nature of the NCG and the potential explosion hazard must be carefully considered in plant design and training. The rupture or other failure of the gas handling system could allow these gases to enter the recovery boiler building in hazardous concentrations. Effort should be made to minimize the routed distance of CNCG piping inside the boiler house. Personnel Safety Procedures and Training of personnel must be implemented for the additional equipment and systems. Continuous monitors for TRS must be installed to warn personnel in the event of a leak. For extra precaution, operations personnel can be equipped with respirators.

The DNCG stream will generally contain gas compounds at a much lower concentration representing a reduced health hazard. There have been reports of operating personnel suffering nausea as a result of the gases escaping into the recovery building. The digester vent gas could be at a concentration higher than other DNCG streams and thereby constitute an increased hazard. This *Good Practice* recognizes alternatives for handling the DNCG in the recovery boiler building in Chapter 4.

The American Petroleum Industry has published API Recommended Practice 55 that in Appendices summarizes the *Physical Properties and Physiological Effects of Hydrogen Sulfide*[5] and *Physical Properties and Physiological Effects of Sulfur Dioxide*[6]. The first Appendix includes Tables A-1 of typical characteristics of Hydrogen Sulfide and A-2, Summary of Occupational Exposure Values for Hydrogen Sulfide.

Other liquid waste streams will not generally represent a direct personnel hazard as these are contained in piping systems to the recovery furnace. Health hazards would occur if there was a rupture or other failure of the piping system.

3.9 System Complexity

Adding additional gas or liquid streams to a recovery boiler increases the system complexity. With the availability of distributed control systems, proper training, and proper design of the systems, recovery boilers can be operated with the added complexity without posing a threat to safe operations. DNCG can be viewed as odorous air and adds minimal complexity, but CNCG, SOG, and other liquid streams should be treated similar to an auxiliary fuel with specifics on safety interlock requirements as provided in the following chapters.

[5] Appendix A, with Tables A-1, Hydrogen Sulfide, and Table A-2, Summary of Occupational Exposure Values for Hydrogen Sulfide, API Recommended Practice 55, Recommended Practices for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide.
[6] Appendix B, Practice 55, Physical Properties and Physiological Effects of Sulfur Dioxide.

Operational upsets are a major consideration in the design and operation of the system to introduce the CNCG into the recovery furnace. Instabilities in the gas incineration system could upset the boiler operation or distract the operator's attention. This increases the vulnerability of the recovery boiler to other hazards. Similarly, upsets in the recovery boiler may lead to unsafe conditions for the thermal oxidation of the CNCG. Either situation requires the immediate diversion of the CNCG to the recovery building vent or alternate point of incineration. Failure to satisfy any of the normal recovery boiler safety interlocks would be a further cause for immediate diversion of the CNCG from the recovery boiler, as would the load on the boiler falling below the level prescribed within this *Good Practice.* The conditions for tripping and diverting this stream from the boiler will be addressed more specifically in Chapter 5 titled "Guidelines for Thermal Oxidation of CNCG and SOG".

Chip bin NCG (CBNCG) adds a level of complexity due to the potential for turpentine being present in the transport system to the recovery furnace. The chip bin gases can be a separate gas stream or can be included in the DNCG stream. The conditions for tripping and diverting this stream from the recovery furnace are addressed more specifically in Chapter 8.

Other liquid waste streams are introduced by mixing with black liquor or in dedicated burners. Those liquids mixed with black liquor can add complexity to the black liquor firing system. Those liquids fired in dedicated burners add complexity associated with the presence of an additional burner in the recovery furnace and the recommended interlocks for safe operation.

3.10 Integration/Reliability of Transport Systems

While proper design of the transport systems is an important facet of liquid and gaseous waste stream combustion, it is beyond the scope of this document. Waste streams must be properly conditioned.

Specifications for gas conditioning required for introduction to the recovery boiler are included in Chapters 4, 5 and 8. Interlocks should be designed so that, in the event the specified gas or boiler conditions are not met, or there is an instrument failure, the transport of gases is isolated from the recovery boiler. In other words, the system must be "fail safe".

Specifications for liquid streams in black liquor or fired in dedicated burners for introduction to the recovery boiler are included in Chapters 6 and 7.

3.11 Input

The design of a new recovery boiler provides the engineer the opportunity to take into account the additional heat input that may be entering the furnace with the liquid and gaseous waste streams. The furnace size, additional burner requirements, and placement

of the entry points for waste streams, as well as the location and air volumes for air ports, can be optimized by the designer.

The design evaluation to thermally oxidize NCG in an existing recovery boiler must consider all boiler and auxiliaries limitations. These limitations will vary on a case-by-case basis. In cases where the recovery boiler capacity is limited by the heat input, it may be necessary to decrease proportionately the input of black liquor when firing waste streams. As an order of magnitude example, if a mill is firing CNCG and SOG at 3000 ACFM with an average heating value of 65 BTU/ACF the heat input is 11.7 million BTU/hr. Assuming the recovery boiler at maximum heat input is burning 3.5 million lb/day of black liquor solids with a heating value of 6600 BTU/lb, the heat input from liquor is 962.5 million BTU/hr. Thus the heat input from CNCG/SOG is equivalent to approximately 1.2% of the heat from liquor (i.e., the mill would need to consider reducing the liquor firing in order to reduce the liquor heat input by 1.2%).

Many North American recovery boilers being considered for the thermal oxidation of CNCG will require an increased level of solids concentration to assure that SO_2 is not leaving the boiler. The additional benefit to raising the solids concentration is that the flue gas volume is reduced, thereby providing an opportunity to increase heat input without increasing the gas velocity in the furnace or through convection surfaces. The actual heat input for NCG will depend on the composition of the stream. The heats of combustion for different NCG components are listed in Table 2.

Table 2 Heats of Combustion for NCG Components[7]

Component	HHV (BTU/lb)
Methanol (gas)	9,770
Turpentine	17,870
Hydrogen Sulfide	6,570
Methyl Mercaptan	11,220
Dimethyl Sulfide	13,280
Dimethyl Disulfide	10,160

3.12 Condition of the Recovery Boiler

In general, it is always easier to design an auxiliary system for new construction as opposed to retrofitting an existing unit. As mentioned above, heat input can be a concern for an existing unit. Older units in particular have short furnace heights that compromise residence time and heat release per unit of volume. The furnace wall construction is another consideration; units pre-dating membrane wall construction have questionable integrity of the walls to contain the waste streams. For DNCG, the integrity of the duct work can also become a major concern. If the condition of the duct work is not considered suitable for transport of DNCG, then a separate duct system may have to be designed. This has been done on some units.

[7] *Collection and Burning of Kraft Noncondensible Gases – Current Practices, Operating Experience, and Important Aspects of Design and Operation*, Technical Bulletin No. 469, NCASI, Aug. 29, 1985.

CHAPTER 4 GUIDELINES FOR THERMAL OXIDATION OF DNCG

4.1 Introduction

These guidelines cover the use of the recovery boiler as a control device for safe thermal oxidation of DNCG. Chip Bin NCG (CBNCG) can be one of the DNCG streams that this chapter covers, but Chapter 8 must be referenced to understand CBNCG. This chapter also applies to dedicated systems for thermal oxidation of dissolving tank vent gases in the recovery boiler.

4.1.1 Safety

During the thermal oxidation of DNCG, the safety for both personnel and equipment, as well as health hazards for personnel, must be considered.

The DNCG system is considered an "odorous-air" system and DNCG becomes a substitute for a part of the combustion air supply. DNCG is not a fuel. Systems and equipment for thermal oxidation of DNCG, as well as the systems and equipment for collection and treatment, should be designed and controlled such that:

- The escape of DNCG into the recovery building area is prevented insofar as design makes it possible.
- Condensate cannot carry into the recovery boiler.
- Special consideration should be placed on the design of the system for collecting and handling the digester chip bin gases recognizing that conditions can occur where the concentration can become flammable.
- In no case shall the safety requirements be less restrictive than those presented in the following BLRBAC publications:

    1. Recommended Good Practice for the Safe Firing of Auxiliary Fuel in Black Liquor Recovery Boilers
    2. Recommended Good Practice for the Safe Firing of Black Liquor in Black Liquor Recovery Boilers
    3. Instrumentation Checklist and Classification Guide for Instruments and Control Systems Used in Operation of Black Liquor Recovery Boilers
    4. Recommended Rules for Personnel Safety Black Liquor Recovery Boilers

4.1.2 Sources

The main sources of DNCG may include:

- Chip bin vents
- Digester blow and stock surge tank vents
- Digester stand pipe vents
- Brown stock and post-oxygen delignification washer vents

- Cylinder molds/decker hood vents
- Oxygen reactor and oxygen blow tank vents
- Knotter and screening reject drainer vents
- Miscellaneous filtrate and stock tank vents in fiberline operations
- Weak and strong black liquor storage and mixing tank vents
- Crude tall oil soap skimming tank vents
- Clean evaporator process condensate tank vents
- Recovery boiler dissolving tank vents

Regarding the selection of suitable DNCG sources, see the Section in this Chapter on Collection of DNCG.

4.1.3 Recovery Boiler Introduction System

DNCGs can be introduced for thermal oxidation into the recovery boiler furnace in several ways.

- Into the suction of the forced draft fan (primary, secondary, tertiary).
- Into the primary, secondary or tertiary air duct either prior to or after the steam coil air heater.
- Through multiple injection nozzles located in a suitable furnace air zone.

The selected method of introduction of the 'odorous air' into the furnace needs to consider the gas concentration at the point of injection and the volume of DNCG. The designer selecting a system to introduce DNCG into the air duct should recognize the potential for release of odorous gas into the boiler area due to ductwork leaks, port rodding leakage, sight glass breakage or other leakage sites. A system design that uses direct injection into the furnace through multiple dedicated nozzles significantly reduces the possibility of odorous gas release.

DNCG replaces a part of the volume of combustion air. Accordingly, the pressure and temperature of the DNCG at the point of introduction should optimally match the conditions of the air being replaced. The volume of DNCG relative to the air volume is a factor to consider. Consideration needs be given for each installation to the percent of the air being replaced in an air zone. DNCG introduction at the tertiary level, that is, above the liquor gun level, may not be appropriate because the volume of DNCG may equal or exceed the full load tertiary air requirement. This could result in conditions of operation where the furnace might become air deficient. The operating function and load characteristic of the "above gun" air required becomes the most important consideration for design of a DNCG system. From a functional standpoint, it may be desirable to use a portion of ambient air for the required combustion air to provide flow modulation for oxygen control and turndown at reduced boiler operating loads.

The exact method of introduction of gas into the recovery boiler is determined during system design in consultation with the boiler manufacturer, process safety resources and insurance carriers.

4.2 Collection and Transfer of DNCG

The placement outside the recovery boiler area of the collection and the transfer motive equipment (fan or blower) shown in Figure 1 for the DNCG system should consider the need for access to equipment when the recovery boiler area is evacuated for an ESP. Access is layout dependent. For example, if the DNCG block and vent is upstream of the transfer fan or blower, there is probably no need to access equipment. The "recovery boiler area" corresponds to the area to be vacated in the event of an ESP.

The introduction and diversion of DNCG should be controlled from the recovery boiler control room.

4.2.1 Collection of DNCG

A thorough sampling and evaluation study of all components entering the dilute gas system should be performed to determine the temperature, volumetric flow, moisture content, and %LEL of each individual source. This study should include both normal steady state operation and maximum rates with upset conditions. This data should be used by a qualified specialist to determine the operating conditions and properties of the combined DNCG stream at the recovery boiler. All liquor based vents will exhibit lower LEL levels for hardwood liquor than for corresponding softwood liquor vents.

4.2.2 Chip Bin Gas

Chip bin noncombustible gas (CBNCG) is covered in detail in Chapter 8. In that the Chip Bin can be the most significant NCG source that can jeopardize the safety of a combined DNCG system, particular attention should be given to the detailed discussion provided in that chapter. An evaluation of risk factors is necessary to qualify a particular chip bin vent gas as "blendable" with DNCG. If a particular CBNCG qualifies for blending, then the DNCG guidelines in this chapter (Chapter 4) can be used for that CBNCG.

4.2.3 Dissolving Tank Vent Gases

Dissolving tank vent gases are DNCGs containing primarily air and water vapor. Dissolving tank vent gases should only be handled through a dedicated system for the following reasons:

- The dissolving tank only operates when the boiler is on line, while generation of other DNCGs is dependent on their process source. By separating dissolving tank DNCG from other process DNCGs, designing for a wide range of flow is avoided.
- The dissolving tank DNCG flow is very large. If it is combined with other DNCGs, the total DNCG volume may be too large for any single method of delivery to the recovery furnace.
- By keeping the dissolving tank stream separate from the other DNCG streams, a different furnace injection method can be used for each stream.

- Dissolving tank vent gases and DNCGs are covered by different environmental regulations.

4.2.4 DNCG Transfer System

The intent of the DNCG transfer system is to reduce the amount of water vapor and condensable gases. The condensate would be typically transferred to a foul condensate collection system.

The DNCG stream should be conditioned to prevent liquid condensate from entering the furnace and/or contributing to corrosion of carbon steel ductwork and other air system components. Mixing of the DNCG with combustion or dilution air at a lower temperature than the DNCG can cause condensation. A maximum of 50% relative humidity in the DNCG stream is a typical target to avoid condensation after mixing with an air stream but higher relative humidity might be possible in some systems. To achieve a condition of 50% relative humidity, the DNCG would likely be cooled to 110°F or lower. The DNCG should be reheated before injection into the recovery boiler air system or furnace. The expected DNCG temperature after reheating would be 150°F if the gas is cooled to 110°F. Should the cooled gas temperature be above 110°F, a higher reheating temperature would be expected. A mist eliminator (or other method of water/gas separation) should be provided to remove condensate.

A dissolving tank vent gas collection system should include a scrubber/cooler to remove water, particulate and green liquor droplets. The scrubber/cooler should be upstream of the DNCG system fan to avoid deposits on the fan rotor and resulting imbalance. There is no a need for a separate mist eliminator in dissolving tank vent gas systems if the scrubber/cooler has an integral mist eliminator.

The principal motive force for transferring the DNCG to the boiler shall be provided by system fan(s)/blower(s) as shown on Figures 1 and 4. All system fan(s)/blower(s) should be of non-sparking construction. The transport system including the fan casing and shaft should be grounded. The fan casing should have a sealed condensate outlet at its lowest point.

For systems with injection into combustion air ducts, DNCG flow and pressure should be monitored and alarmed. These systems will generally include a transfer fan(s)/blower(s) to transport the DNCG to the boiler area and into the air system that uses a combustion air fan. For systems with dedicated injection nozzles, the transfer fan(s)/blower(s) may be designed to develop the DNCG pressure required at the furnace nozzles. DNCG pressure should be monitored and alarmed.

The piping system beginning at the common collection point (suction of fan(s)/blower(s)) shall typically include the following equipment (see Figures 1 and 4).

- Transfer fan(s)/blower(s)
- Local pressure/vacuum indicators before and after prime mover [fan(s)/blower(s)]

- Pressure transmitters with high and low alarms for monitoring and control located before and after transfer fan(s)/blower(s)
- Gas cooling, condensing, and mist entrainment separating equipment
- Automatic vent valve to atmosphere
- Optional tie-ins with automatic switchover to alternate oxidation control device
- DNCG gas temperature conditioning equipment (Reheat can be accomplished by a steam preheater, using the combustion air heating system, or mixing with combustion air.)
- System low point drains with loop seals
- Automatic shut-off valve with means to positively double block and vent. The double block and vent ensures sealing DNCG from the boiler and provides maintenance access.
- Flow and pressure transmitters with alarm functions
- Temperature transmitters with high/low alarms for gas condensers/preheaters

Automatic vent lines for DNCG systems should be routed to a safe location.

For DNCG systems handling dissolving tank vent gases, there must be an additional vent directly from the dissolving tank to a safe location, which will open on dissolving tank high pressure.

4.2.5 DNCG Piping System and Auxiliary Equipment

Good engineering practices should be employed for all design aspects of the DNCG gas system including metallurgy selection, transport velocities, sloping and draining of piping, accessibility and **safety**.

The DNCG equipment and transport piping or ducting inside the boiler area should be minimized as much as possible to reduce exposure to gas leakage. The control mechanisms should be user friendly. **Proactive** maintenance and repairs for all electrical and mechanical equipment should be practiced.

A DNCG system handling dissolving tank vent gases can have build up problems from particulate and green liquor droplets. It should have provisions for frequent cleaning of heat exchangers – either installed spares or planned maintenance periods. Provisions should also be made for frequent planned maintenance of flow measurement devices.

Materials of construction for ductwork, piping, and equipment in contact with wet unconditioned DNCG should be AISI type 304L or 316L stainless steel, or other metals with equivalent or better corrosion resistance and strength properties.

Gas piping should be designed to prevent accumulation of condensate and flammable deposits. Generally, piping should be sloped in the direction of gas flow to minimize deposits. A low point with a liquid seal drain should be provided in the gas line prior to injection into the recovery boiler system. From the last drain to the recovery boiler, the piping should be designed to prevent condensate from entering the recovery boiler.

Sealed liquid drains should have a method of verifying that the seal is in place. Since fiber and organic deposits can be expected, provisions should be made for inspection and cleaning on periodic preventative maintenance schedules.

When a DNCG line is idle due to the boiler being down or when the DNCG is transferred to another incineration point, it is recommended, but not required, that the line downstream of the last shut off valve be purged of NCGs. This may be done with mill air or with a slip stream from existing intake or combustion air as long as there is no NCG component mixed with the air. The steps in this process may be programmed in the permissive logic during the "ventless transfer" or the shutdown of the boiler. This should be designed for a single purge, immediately after idling.

In addition to purging the idle DNCG lines, it is also recommended that the DNCG nozzles that penetrate the boiler be evaluated for possible cooling during long idle periods when the boiler is still operational. The idle nozzles lose the cooling properties from the DNCG flow and are subject to degradation. The owner may consider using mill air for short periods, or piping in a slip stream from a DNCG-free combustion air source.

Piping should not be routed close to critical areas such as furnace corners (to the extent possible), or near areas likely to be occupied by personnel such as normal access ways. For boilers designed with a "weak corner", the area in the vicinity of the corner should also be avoided. Piping should be constructed according to all applicable codes; recognition needs to be given to pressure, explosion hazards, and static charge build-ups. If a system can be subject to deflagration pressure then consideration should be given to designing for that possibility.

Automatic shut-off valves in DNCG piping should be equipped with fail-closed actuators. Automatic vent valves to atmosphere should be fail-open. Gases should be securely isolated when shutting down the thermal oxidation system, therefore, valves in the system must be chosen carefully with attention given to shut-off classifications. Automatic valves should have position with feedback to a manned control room switches to confirm valve position status.

4.3 Monitoring and Control

Monitoring and control for the DNCG system should be in accordance with any information that is a part of the BLRBAC "Instrumentation Checklist and Classification Guide for Instruments and Control Systems Used in Operation of Black Liquor Recovery Boilers". The system design should evaluate NFPA Standards for guidelines for system design and comply with insurance carrier recommendations.

Bearing failures in transfer blowers have been sources of ignition and consideration should be given to providing continuous or routine vibration and bearing temperature monitoring.

NFPA 69, Chapter 6, sets the allowable level of combustibles. Systems without automatic interlocks should be designed to operate below LEL levels of 25%. Operation of DNCG up to 60% LEL is permitted if automatic interlocks are provided and operational.

DNCG systems that include Chip Bin NCG may be prone to upset conditions where high percent LEL levels can occur. The risk of developing flammable conditions should be evaluated to determine whether continuous percent LEL monitoring is warranted. Guidelines provided in Chapter 8 may be useful in this regard.

4.4 Safety Systems

The DNCG system is considered an "odorous-air" system and a part of the combustion air supply, not as a fuel, and should be considered as an air stream when applying the appropriate sections of the BLRBAC Recommended Good Practices for Safe Firing of Auxiliary Fuel and Black Liquor in Black Liquor Recovery Boilers.

4.4.1 Permissive Starting Logic - DNCG

To admit DNCG to the recovery furnace, the following conditions should be fulfilled:

- Purge credit established and maintained
- Steam flow is above 30% of MCR
- DNCG temperature after reheat not low
- DNCG temperature after condenser not high
- DNCG flow above minimum
- If vent gas from a steaming chip bin is included in the collection system, the chip bin gas temperature after the gas cooler is not high
- Dissolving tank pressure not high (if applicable)
- DNCG temperature after scrubber/cooler for dissolving tank vent gas below maximum (if applicable)

Permissive starting logic for thermal oxidation of DNCG is shown in Figure 2, which is supported by a Logic Explanation Chart.

4.4.2 Protective Tripping Logic - DNCG

Any of the following conditions will disallow introduction of DNCG to the recovery furnace:

- Master Fuel Trip (purge credit lost)
- DNCG flow low
- Gas temperature after chip bin gas cooler high (if applicable)
- DNCG temperature after gas condenser high
- DNCG temperature after reheater low
- Boiler steam flow less than 30% of MCR
- Shut-off valve to alternative control device not closed (if applicable)

- Automatic vent valve not closed.
- Dissolving tank pressure high (if applicable)
- DNCG temperature after scrubber/cooler for dissolving tank vent gas high (if applicable)

Protective tripping logic for thermal oxidation of DNCG is shown in Figure 3, which is supported by a Logic Explanation Chart.

4.5 Personnel Safety

Operational problems, which have to do with collecting, treatment and destruction of DNCG can lead to accidents and serious injury.

The DNCGs contain, among other things, H_2S, organic sulfides and methanol, and at certain times, even high levels of turpentine. In addition to the health risk, there is also risk of a gas explosion.

OSHA Guidelines should be reviewed regarding the risks and precautions for hazardous compounds present in DNCG.

The installation of a TRS monitoring system to detect unsafe levels of gas in the boiler area should be considered. Monitoring should be in accordance with federal, state, local, and mill safety codes and regulations.

Daily inspection and control is needed to check for leaks in systems for DNCG. Leaks in the system shall be corrected immediately.

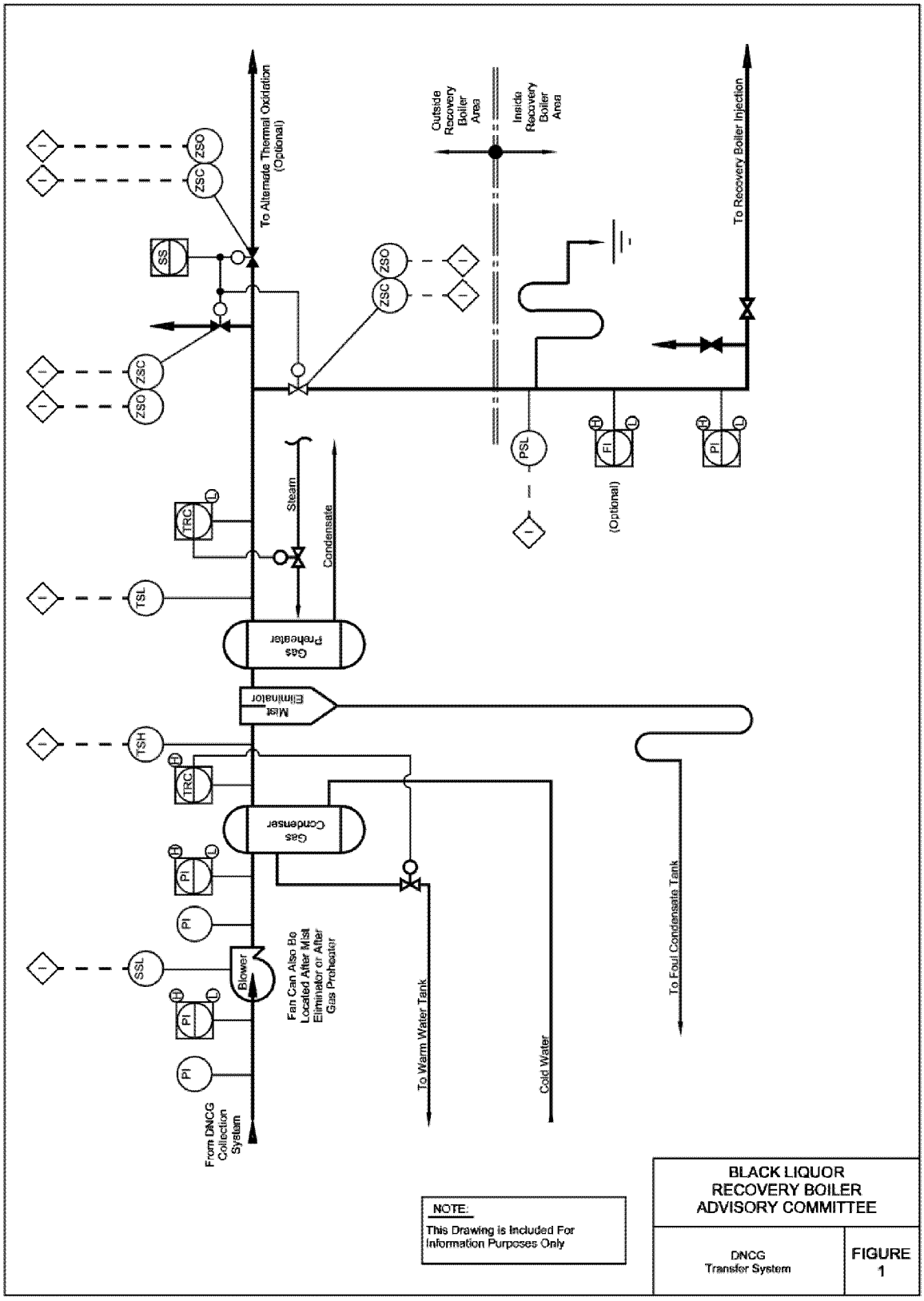

Figure 1 DNCG Transfer System.

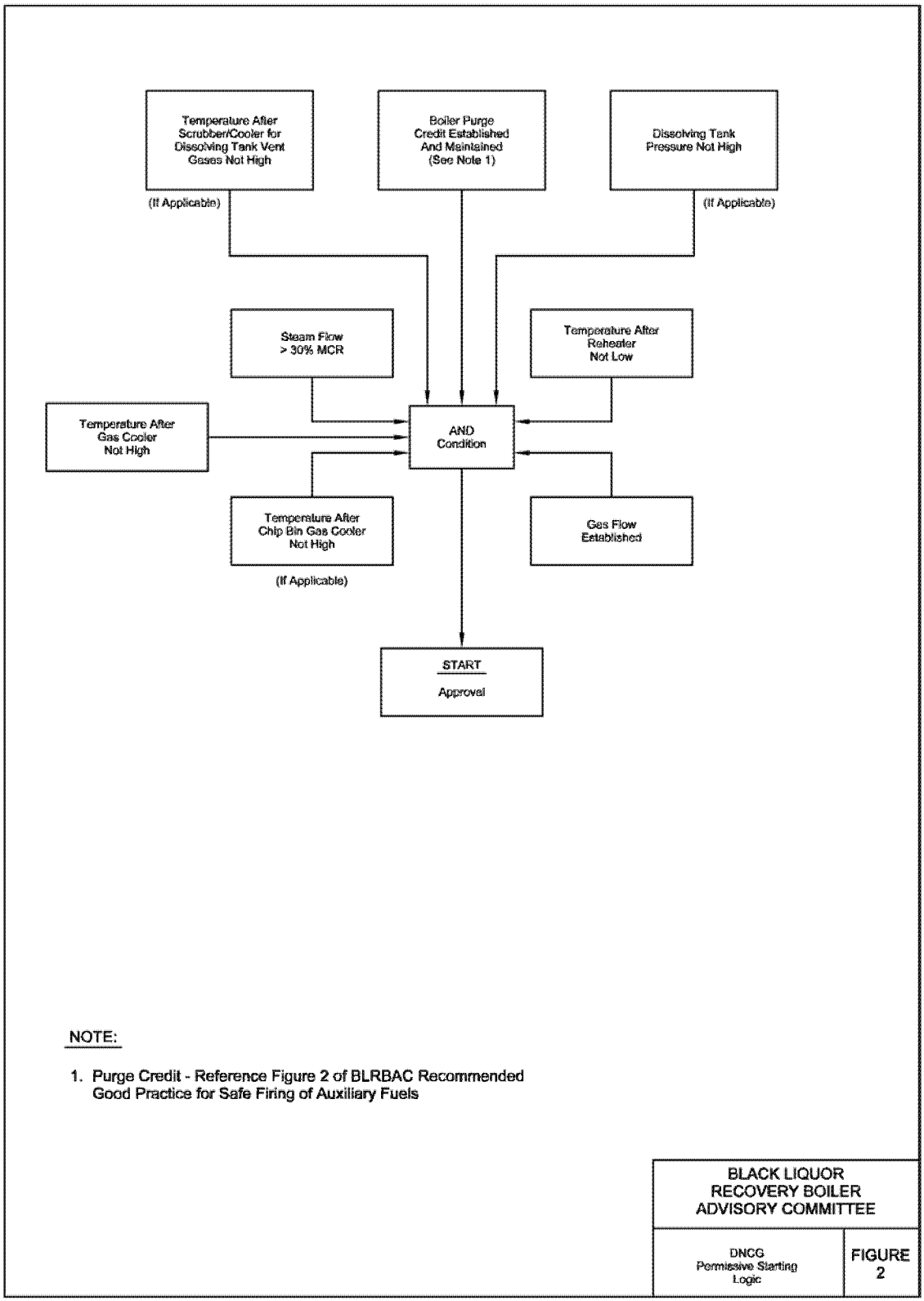

Figure 2 DNCG Permissive Starting Logic

Table 3 Logic Explanation Chart for Figure 2 - DNCG Injection Permissive Starting Logic

LOGIC BLOCK	PURPOSE	HAZARD PROTECTED
Boiler Purge Credit Maintained (From Figure 2 'Common Permissive Starting Logic' in Safe Firing of Auxiliary Fuel Recommended Good Practice)	Ensure firing permissive	Prevent introduction of DNCG while boiler is not being fired.
Steam flow >30% MCR	Ensure furnace combustion is stable.	Unstable operation of boiler may minimize furnace residence time or too low of temperature for oxidation.
Temperature after reheater not low	Ensure proper gas phase of DNCG	Prevent liquid from entering boiler.
DNCG flow established*	Ensure sufficient motive force	Flame propagation up nozzle or pipeline.
Temperature after gas cooler not high	Ensure proper gas properties	Reduce gas volume and moisture.
Temperature after chip bin gas cooler not high	Ensure proper gas properties	Explosion hazard due to entrainment of turpentine.
Start Approval	Start permissive after satisfying interlocks	Interlocks made.
Dissolving tank pressure not high (if applicable)	Ensure stable dissolving tank operation	Prevents pressure pulse from dissolving tank from affecting DNCG system operation.
Temperature after scrubber/cooler for dissolving tank vent gases not high (if applicable)	Ensure proper gas properties	Reduces gas volume and moisture

* Flow can be proven with pressure, flow, fan operating and control damper position (fan operation should be proven with shaft speed), or other means.

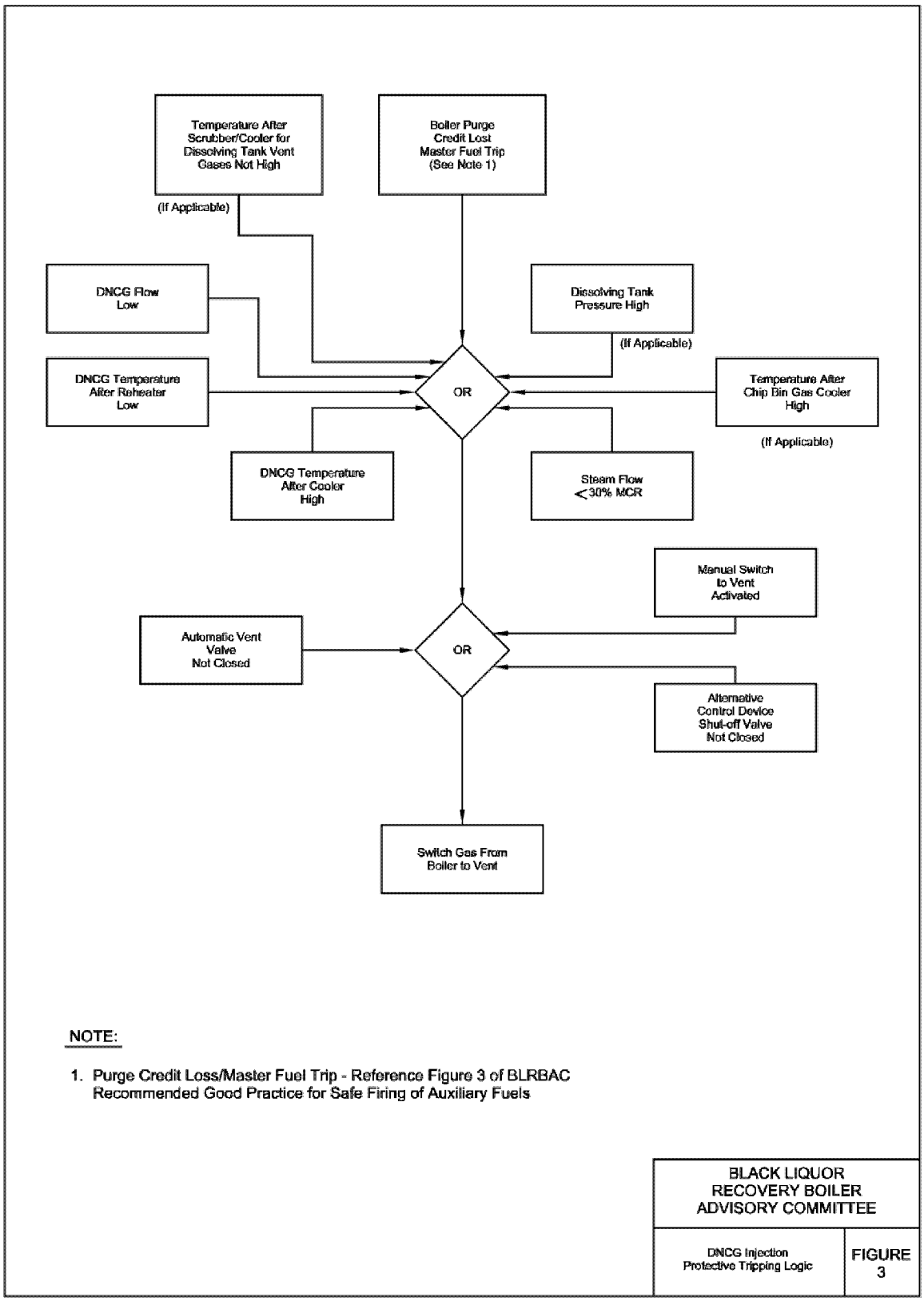

Figure 3 DNCG Injection Protective Tripping Logic.

Table 4 Logic Explanation Chart for Figure 3 - Injection Protective Tripping Logic

LOGIC BLOCK	PURPOSE	HAZARD PROTECTED
Boiler Purge Credit Lost Master Fuel Trip (From Figure 3 'Common Permissive Starting Logic' in Safe Firing of Auxiliary Fuel Recommended Good Practice)	Stop DNCG introduction when boiler firing permissives not met	Prevent introduction of DNCG while boiler is not being fired.
DNCG flow low*	Ensure sufficient motive force	Flame propagation up nozzle or pipeline.
DNCG temperature after reheater low	Ensure proper gas phase of DNCG	Prevent liquid from entering boiler.
DNCG temperature after cooler high	Ensure proper gas properties	Entrainment of liquid, Explosion if temperature above auto-ignition point.
Steam Flow <30% MCR	Ensure furnace combustion is stable.	Unstable operation of boiler may minimize furnace residence time or provide too low a temperature for proper oxidation.
Temperature after chip bin gas cooler high	Ensure proper gas properties	Excursions above LEL.
Automatic vent valve not closed	Ensure stable flow	Unstable flow due to leakage.
Manual switch to vent activated	Firing not desired	System exposed to flame source with no minimum flow signal.
Alternative control device shutoff valve not closed	Ensure stable flow	Unstable flow due to flow bypass.
Switch DNCG from boiler to vent	Stop DNCG flow into boiler when parameters are out range.	Hazardous conditions in the DNCG system or boiler.
Dissolving tank pressure high (if applicable)	Ensure stable dissolving tank operation	Prevents pressure pulse from dissolving tank from affecting DNCG operation.
Temperature after scrubber/cooler for dissolving tank vent gases high (if applicable)	Ensure proper gas properties	Entrainment of liquid.

* Flow can be proven with pressure, flow, fan operating and control damper position (fan operation should be proven with shaft speed), or other means.

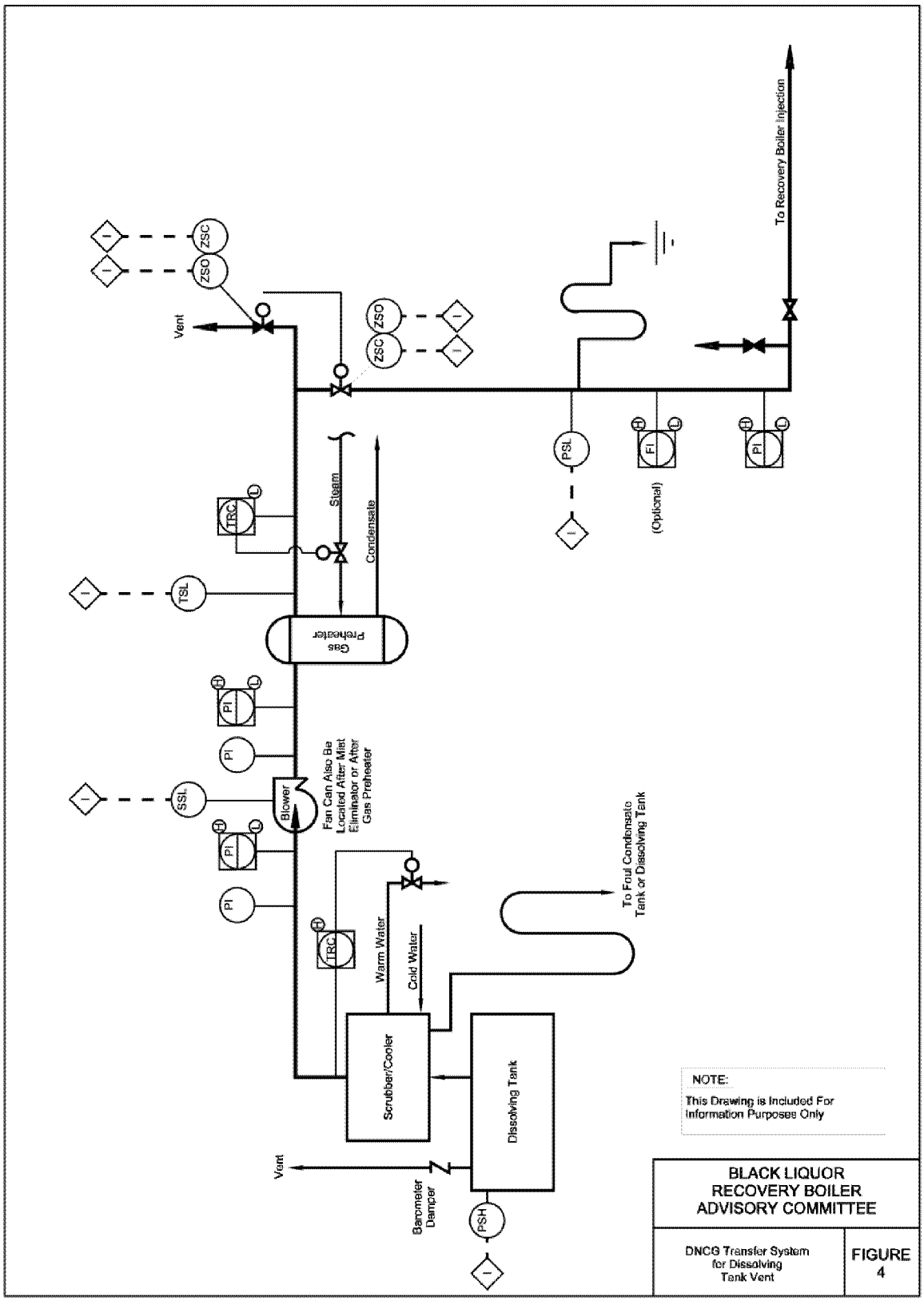

Figure 4 DNCG Transfer System of Dissolving Tank Vent.

CHAPTER 5 GUIDELINES FOR THERMAL OXIDATION OF CNCG AND SOG

5.1 Introduction

This *Recommended Good Practice* presents the use of the recovery boiler as the control device for thermal oxidation of CNCG and SOG.

5.1.1 Safety

During the thermal oxidation of CNCG and SOG, the safety hazards for both personnel and equipment have to be considered.

The equipment for thermal oxidation as well as collection and treatment of CNCG should be designed and controlled such that:

- CNCG cannot escape into the recovery boiler building area.
- Condensate cannot carry into the recovery boiler.
- Fire and explosion in equipment and pipe systems is prevented.
- Positive ignition of gases entering the furnace is provided.

In no case shall the safety requirements be less restrictive than those presented in the following BLRBAC publications:

- Recommended Good Practice for the Safe Firing of Auxiliary Fuel in Black Liquor Recovery Boilers.
- Recommended Good Practice for the Safe Firing of Black Liquor in Black Liquor Recovery Boilers.
- BLRBAC Recommended Rules for Personnel Safety for Black Liquor Recovery Boilers.
- Instrumentation Checklist and Classification Guide for Instruments and Control Systems Used in Operation of Black Liquor Recovery Boilers.

5.1.2 Sources

5.1.2.1 CNCG

The main sources of concentrated noncondensible gases (CNCG) are:

- Noncondensible gases from black liquor evaporation
- Vents from foul condensate tank, turpentine decanter, turpentine tank, methanol tank and various pumping tanks.
- Vents from flash tanks, condensers and specialty process equipment--these need to be evaluated on an individual basis concerning classification as a dilute or concentrated NCG. The digester chip bin vent gases cannot be included in the CNCG system because of high air content.

5.1.2.2 SOG

SOG from a foul condensate steam stripper is handled in a separate and independent system for introduction into the recovery furnace for thermal oxidation. These gases generally are the gas product from the stripper reflux condenser and reflux tank, and consist principally of water vapor, methanol, reduced sulfur components and potentially small amounts of turpentine and other hydrocarbons. An additional process step is incorporated in some mills to condense the methanol from the gases and handle the methanol liquid stream separately.

Vents from a high solids concentrator system are similar in nature to the SOG from a stripper column and should be handled in a gas system similar in design to that used for SOG. The system should be independent of other NCG systems from the source to and including the burner gun.

As an option, SOG can be modified by removing its methanol content. The remaining gas is a low volume CNCG.

5.1.3 Dedicated Burner

A dedicated burner should be used for thermal oxidation of CNCG and SOG in the recovery boiler. The burner should be equipped with an NFPA Class 1 continuous igniter and igniter flame scanner. This arrangement will provide more stable and safer firing of the gases than arrangements that depend on the heat from black liquor combustion to sustain the thermal oxidation of the NCG. This arrangement further considers that there is not a reliable means of detecting a loss of black liquor flame to shut off the NCG flows to the recovery boiler.

5.1.4 The Recovery Boiler as Primary Control Device

When the recovery boiler is used, it should be the primary control device. In the recovery boiler the sulfur compounds in the NCG are captured back into the process. When the recovery boiler is the primary control device, the effect of the NCG on the recovery boiler sodium-sulfur balance will be constant. This balance would be changing if the recovery boiler were used as a secondary control device with the NCG being thermally oxidized in the boiler intermittently.

5.2 Collection and Transfer of CNCG and SOG

A thorough sampling and evaluation study of all components of the CNCG and SOG should be performed to determine temperature, volumetric flow, moisture content and percentage UEL of each individual source. That study should include both normal steady state operation and maximum rate with upset conditions. This data should be used by a qualified specialist to determine the operating condition and properties of the combined CNCG streams and the SOG stream at the recovery boiler.

Consider locating motive equipment for collecting gases and the diversion system in an area outside the recovery boiler area so they can be accessed even at times when the recovery boiler area is evacuated. Where facilities are subject to winter climates with temperatures below freezing, consideration should be given to locating the equipment in a warm enclosure. Control of the system should be from the recovery boiler control room.

The engineer should give highest piority to the selection of the ejector and other control components to maximize the best control and safety of the CNCG system.

5.2.1 CNCG

The sources of gases connected to the CNCG system must be of such nature that air cannot enter the system.

The CNCG from the common collection point to the waste streams burner can be handled in two different ways.

- Vapor phase transfer system (no gas conditioning involving any change in component concentration)
- Conditioned gas transfer system

5.2.1.1 Vapor Phase Transfer System

After the common collection point the gases are moved by means of a steam ejector or water ring blower directly to the waste streams burner system. No conditioning involving any change in component concentration is done.

The piping system starting at the steam ejector (water ring blower) typically includes the following equipment.

Figure 5 - Equipment Outside the Recovery Boiler Area

- Steam ejector or water ring blower
- Pressure transmitter for monitoring with high and low alarms located after the steam ejector (water ring blower)
- Mist eliminator(s) (with pressure drop monitoring and high pressure drop alarm)
- Flow transmitter with interlock function
- Main header vent line with automatic valve, drain function included
- Recovery boiler line automatic shut-off valve
- Tie-in to alternate thermal oxidation device (optional)
- Steam purge connection

Figure 6 - Equipment Inside the Recovery Boiler Area

- Recovery boiler vent line with automatic valve, drain function included

- Automatic double block and bleed valves (located close to burner)
- Pressure and temperature switches for interlock functions located before the automatic double block and bleed valves
- Monitoring pressure and temperature transmitters with high and low alarms located before the automatic double block and bleed valves

Flame arresters or detonation arresters (with pressure drop monitoring and high pressure drop alarm) located as close to the burner as possible.

The following equipment will be located in the system as required.

- Rupture disk(s)
- Low point drains
- Steam Heat tracing and /or indirect steam preheater (not shown in figures)

The intent of the design for the system is to ensure that no condensates of the condensible components--methanol, water or turpentine--can collect and cause upsets to the waste streams burner system or the recovery boiler. The CNCG piping should be heavily insulated from the source to the waste streams burner to minimize condensation formation in the line. Depending on local conditions, heat tracing may be considered.

5.2.1.2 Conditioned Gas Transfer System

The following components are included in addition to those used in a vapor phase transfer system.

- Gas cooler / condenser
- Indirect steam preheater with auxiliaries

A concentrated NCG system with a seal pot is considered to be a conditioned gas transfer system. The seal pot is used to isolate lines and prevent flashback. It will act as a quench cooler and thereby will perform partial condensation.

The intent of the Conditioned Gas Transfer System is to reduce the amount of water vapor and condensible gases and increase thermal efficiency by reducing the loss due to water vapor. The condensate would be typically transferred to a foul condensate treatment system which may include a steam stripper.

The gas analysis needs to be carefully evaluated before and after the condenser with regard to explosion range and combustion characteristics to determine the impact of conditioning on the gas. Condensing of large amounts of water vapor, methanol and turpentine may shift the resulting gas mixture into the explosive range depending on the residual amount of infiltration air and the combustible gas concentrations. The heating value and combustion characteristics may also be changed due to condensing of turpentine and methanol.

It is recommended to heat the gas after the cooler and/or heat trace the down stream piping to raise the operating temperature of the gas burner system to well above the dewpoint and thereby protect it from upsets due to condensates.

5.2.2 SOG

SOG is primarily a mixture of TRS compounds, methanol and steam at saturated steam conditions that can be hotter than other CNCG. Frequently, the pressure of the gas at the stripper condenser discharge is much higher than that of other CNCG streams. The SOG must be handled in lines separate from the other CNCG to prevent condensation of the SOG constituents in the collection system and to handle the differences in pressure. The SOG handling system does not provide conditioning involving any change in component concentration with the exception of a stripper system where methanol is condensed and recovered as a liquid.

Upset conditions caused by black liquor carryover or evaporator boilout can result in generating foam in the condensate stripper. This foam can then be transported with the SOG to the recovery furnace. Provisions must be made to prevent foam carryover into the SOG to preclude introducing foam into the furnace.

The SOG piping should be heavily insulated from the source to the waste streams burner to minimize condensation formation in the line. Steam tracing of the stripper off-gas piping should be considered in cold climates.

If the stripper off-gases at the source are at an adequate pressure to provide the motive force to transport them to the waste streams burner, then the piping system leading to the burner typically would include the following equipment. This arrangement would also apply to CNCG from a high solids concentrator.

Figure 5 - Equipment Outside the Recovery Boiler Area

- Pressure transmitter for monitoring with high and low alarms
- Mist eliminator(s) (with pressure drop monitoring)
- Flow transmitter with interlock function
- Main header vent line with automatic valve, drain function included
- Recovery boiler line automatic shut-off valve
- Tie-in to alternate thermal oxidation point (optional)
- Steam purge connection

Figure 6 - Equipment Inside the Recovery Boiler Area

- Recovery boiler vent line with automatic valve, drain function included
- Automatic double block and bleed valves (located close to burner)

Pressure and temperature switches for interlock functions located before the automatic double block and bleed valves.

- Monitoring pressure and temperature transmitters with high and low alarms located before the automatic double block and bleed valves.

Flame arresters or detonator arresters (with pressure drop monitoring and high pressure drop alarm) located as close to the burner as possible.

The following equipment will be located in the system as required.

- Rupture disk(s)
- Low point drains
- Heat tracing and/or indirect steam preheater (not shown in figures)

If the SOG at the source are not at an adequate pressure to provide the motive force to transport it to the waste streams burner, then the piping system leading to the burner typically would include the previously mentioned equipment and a steam ejector.

5.2.3 CNCG and SOG Piping System and Auxiliary Equipment

CNCG and SOG should be handled in completely independent collection systems due to temperature and pressure differences between the two streams being handled. There is a risk of condensing methanol from SOG with the cooler CNCG stream.

Due to system pressure differentials, it is recommended that the SOG system and CNCG system not share any common auxiliary equipment such as condensate collection vessels. There is a risk of one system discharging into the other.

Piping system and steam ejector or water ring blower should be sized so that minimum transport velocities for gases are maintained.

Gas piping should be designed to prevent accumulation of condensate and should be designed with the shortest possible pipe run inside the recovery boiler building. The piping should not be routed close to critical areas such as the dissolving tank or the corners of the furnace or near areas likely to be occupied by personnel such as normal accessways.

CNCG and SOG should be securely isolated when shutting down the thermal oxidation system, therefore valves in the system should be chosen carefully with attention given to shutoff classifications. Automatic valves should have position switches to confirm valve position status.

Piping downstream of the mist eliminator should be insulated and heat traced to prevent condensate formation in the line. Consideration should be given to sloping the piping in the direction of gas flow for drainage rather than having horizontal lines. This avoids the accumulation of a quantity of water, which could be suddenly released into the furnace as well as the likelihood of accumulating flammable organic deposits. The designer should

proceed on the basis that there will be condensate in the pipe from time to time and that it must be removed.

Each vent line should have one shut-off valve with "fail open" actuator that will open automatically when waste stream firing to the recovery boiler is stopped.

Each gas line to the recovery boiler should have a flame arrester. There should be a differential pressure tranmitter across the flame arrester to alarm high differential pressure. Provision can be made to clean the flame arrester using steam or inert gas.

Any water or steam connections to the system should have double block and bleed valves or removeable spool pieces per BLRBAC Recommended Good Practice for Safe Firing of Black Liquor in Black Liquor Recovery Boilers. Automatic valves should have position switches to confirm valves position status. Steam piping should be properly designed and trapped to prevent condensate collection. **Air should not be used as a purge medium due to the possible risk of creating an explosive gas mixture**.

If a seal pot (for isolation and flashback prevention) is used, it should be constructed and controlled so that water cannot carry into the recovery boiler through the waste stream line. Therefore there should be two (2) independent protective systems such as switches with alarm and interlock functions. It is imperative that the seal pot not overflow into the CNCG transport line to the recovery boiler.

The condensate collection system should be designed so that it cannot be pressurized causing condensate to back flow to the transport line. As an example, an overflow to a closed sewer system could cause pressurization.

Drains in the system are prone to plugging and should be of a size to reduce that possibility, with consideration given to at least 1-1/2" drain lines.

Materials of construction for ductwork, piping and equipment in contact with CNCG and SOG should be AISI type 304L or 316L stainless steel, or other metals with equivalent or better corrosion resistant and strength properties.

Material containing iron that might turn into FeS in contact with NCG should not be used. Under certain conditions in the presence of air, FeS can oxidize and create heat with explosions or fire as a result.

The system designer must take into account the movement of the waste streams burner due to the expansion of the furnace, and make sure that the movement does not induce unacceptable stresses in the piping.

Piping must meet the required service conditions and be acceptable to the authorities which may have jurisdiction.

5.3 Thermal Oxidation

5.3.1 Burner

The waste stream burner(s) should be mechanically suited for installation and operation in a recovery boiler.

The waste stream burner(s) should have a dedicated air system. The combustion air can be supplied from a separate fan or from the recovery boiler secondary air or tertiary air fan. Proof of adequate combustion air flow is required as proven by a flow switch or other suitable means.

CNCG and SOG should be conveyed to the burner through independent lines and injected into the flame zone separately. A separate system to feed fuel to the continuous igniter is required.

The burner should be placed in the high heat zone of the furnace at or below the tertiary air level. It should be placed in such a manner that disturbances in the continuous flame of the igniter are avoided so as to not create difficulty with detection.

Example of equipment for monitoring and controlling a single burner installation for CNCG and SOG is shown in Figure 6. Multiple burner installations should follow multiple burner standards.

When the NCG system is down, the second automatic shut-off valve should be locked in the closed position. The connections in the CNCG and SOG piping downstream of the shut off valve at the gun should be designed and installed to allow ease of maintenance and inspection on a routine basis.

Cooling of a CNCG/SOG nozzle that is not in use can <u>not</u> be accomplished by injection of air into the CNCG/SOG nozzle.

5.3.2 Continuous Igniter

An NFPA Class 1 igniter (NFPA 8501) is a key element in the thermal oxidation of CNCG and SOG. The capacity of the igniter should be large enough to provide safe ignition and be at least 10 percent of the maximum energy release of the gases being thermally oxidized. The igniter shall be continuous. The igniter should have proof of adequate ignition energy using a low pressure switch on the igniter fuel header.

The igniter can have a common air duct with the burner for CNCG and SOG. Air feed to the igniter should provide stable ignition and operating conditions.

The oil or gas system to the igniter as well as flame monitoring should, in all aspects, follow the BLRBAC Recommended Good Practice for Safe Firing of Auxiliary Fuel.

Light-off of the igniter must be initiated at the burner front, and then only after inspecting the burner opening in the furnace wall to ensure that there is no plugging.

5.3.3 Combustion Air

The recovery boiler secondary or tertiary air fan can be used. If the combustion air is supplied by the secondary air fan, a booster fan may be necessary to provide minimum air pressure to the waste stream burner. The system design should be such that uninterrupted air flow to the recovery boiler for black liquor combustion is first priority.

The following instrumentation for monitoring and control of combustion air should be provided.

- Local pressure indicator
- Suitable means for proving adequate air flow
- Indicating pressure transmitter
- Booster fan running--signal from motor starter, speed switch, etc.

5.4 Safety System

The waste streams burner should have a flame safety system complying with the BLRBAC Recommended Good Practice for the Safe Firing of Auxiliary Fuel. The system design should comply with NFPA standards and insurance carrier recommendations. The waste streams burner flame safety system can be integrated with the auxiliary fuel's burner management system or can be stand-alone.

The permissive starting logic and protective tripping logic contain the logic of Safe Firing of Auxiliary Fuel plus additional requirements. The additional requirements pertain to the quality of the NCG.

Care must be taken to <u>never</u> allow the waste streams burner to maintain purge credit. In other words, the waste streams burner cannot be counted as an auxiliary fuel burner when the burner management system checks if there is an auxiliary burner in service.

5.4.1 Permissive Starting Logic - CNCG

To start thermal oxidation of CNCG in the waste streams burner the following conditions must be fulfilled.

- Purge credit established and maintained
- Steam flow greater than 50% of the steam flow at MCR
- Combustion air fan for waste streams burner running
- Combustion air flow normal
- CNCG flow (velocity) above minimum
- CNCG temperature above minimum
- CNCG pressure not high

- CNCG pressure not low
- Seal pot level not high (if used)
- Burner switch in START position
- Igniter has been in stable operation for minimum one minute
- Igniter interlocks satisfied

Staging of injection of multiple streams into a waste stream burner should be part of the Start Permissives.

Permissive Starting Logic for thermal oxidation of CNCG in the waste streams burner is shown in Figure 7.

5.4.2 Protective Tripping Logic - CNCG

Any of the following conditions will cause the waste streams burner to shut down thermal oxidation of CNCG.

- Master Fuel Trip (purge credit lost)
- Steam flow less than 50% of steam flow at MCR
- CNCG pressure high
- CNCG pressure low
- Combustion air fan for waste streams burner off
- CNCG temperature below minimum
- CNCG flow (velocity) below minimum
- Combustion air flow not normal
- Igniter interlocks not satisfied
- Burner switch in STOP position
- Seal pot level high (if used)

Protective Tripping Logic for thermal oxidation of CNCG in the waste streams burner is shown in Figure 8.

5.4.3 Permissive Starting Logic - SOG

To start thermal oxidation of SOG in the waste streams burner the following conditions must be fulfilled.

- Purge credit established and maintained
- Steam flow greater than 50% of the steam flow at MCR
- Combustion air fan for waste streams burner running
- Combustion air flow normal
- SOG flow (velocity) above minimum
- SOG temperature above minimum
- SOG pressure not high
- SOG pressure not low

- Seal pot level not high (if used)
- Burner switch in START position
- Igniter has been in stable operation for a minimum of one minute
- Igniter interlocks satisfied

Permissive Starting Logic for thermal oxidation of SOG in the waste streams burner is shown in Figure 9.

5.4.4 Protective Tripping Logic - SOG

Any of the following conditions will cause the waste streams burner to shut down thermal oxidation of SOG.

- Master Fuel Trip (purge credit lost)
- Steam flow less than 50% of steam flow at MCR
- SOG pressure high
- SOG pressure low
- Combustion air fan for waste streams burner off
- SOG temperature below minimum
- SOG flow (velocity) below minimum
- Combustion air flow not normal
- Igniter interlocks not satisfied
- Burner switch in STOP position
- Seal pot level high (if used)

Protective tripping logic for thermal oxidation of SOG in the waste streams burner is shown in Figure 10.

5.5 Personnel Safety

Operational problems, which have to do with collecting, treatment and destruction of CNCG can lead to accidents and serious injury.

CNCG contain among other things, H_2S , organic sulfides and methanol, and at certain times, even high level of turpentine. In addition to the health risk, there is also a risk of a gas explosion.

Regarding the risks with hazardous compounds present in CNCG and SOG, see OSHA Guidelines concerning these compounds.

Areas containing NCG piping and equipment should be monitored in accordance with applicable safety codes.

Daily inspection and control is needed to check for leaks in systems for CNCGs and SOGs. Leaks in the system should be corrected immediately.

5.6 System Description and Operation

This section is included to illustrate the application of Chapter 5 guidelines. It is for information purposes only and is not to be considered as additional guidelines.

The arrangement of piping and equipment as shown on the flow sheets (Figures 5 and 6) are the same for both CNCG and SOG. For the purposes of this discussion, the CNCG system is used.

5.6.1 Description

Steam to the gas transport steam ejector has a double block and bleed valve arrangement consisting of valves S1, S2 and S3. This steam connection and other steam connections on Figures 5 and 6 are shown with double block valves and a bleed (or "free blow") valve because they are potential sources of water injection into the furnace. The double block and bleed valve set provides secure sealing plus, with proper sequencing of valve opening, collected condensate can be blown out the bleed line before steam is routed to the gas line.

Downstream of the steam ejector and outside the recovery boiler area, the CNCG line will have a vent to atmosphere controlled by an automated shutoff valve, CG2. Following this vent connection there is an automated valve, CG1, which isolates the branch line to the recovery boiler. If required, there can be a tee ahead of CG1. The tee will allow the gas to be transported to an alternate thermal oxidizer through valve CG3.

It is important that valves CG1, CG2 and CG3 be located outside of the recovery boiler area or in the case of indoor installations in a "designated safe area" so that they are accessible at all times, even in the event of an ESP. Being located outside of the recovery boiler area does not preclude the valves from being in another building.

Immediately downstream of valve CG1 is an automated steam connection consisting of valves S5, S6 and S7. It purges and preheats the next "leg" of CNCG line.

Located immediately before valve CG4 is a line size vent isolated by valve CG7. This vent line serves the CNCG line from valve CG1 to valve CG4. It is used for steam preheating, CNCG venting in anticipation of CNCG firing, and purging after ceasing CNCG firing. The steam for preheating and purging is supplied by the previously mentioned valves S5, S6 and S7.

The vent discharges to the outside of the boiler area. Both this vent and the previously mentioned vent controlled by valve CG2 must be above roofs and away from air intakes. The outlets of these vents must be arranged in such a way that ice plugs are avoided.

A condensate drain from the CNCG line must be included at both vent locations to ensure removal of liquid that is swept along by the venting gases. The drain function can be

included with the vent, or two connections can be used; one to vent and the other to drain the line.

A CNCG line double block and bleed valve arrangement represented by valves CG4, CG5 and CG6 provides the final isolation of CNCG from the furnace. The "bleed", CG5, must be designed so that vapor can be vented from the isolated portion of CNCG line while liquid is vented out of the bottom of the line. Valve CG5 could be two valves, one for venting and the other for draining. The vent from CG5 can be connected to the main vent on the discharge of valve CG7.

The CG4, CG5 and CG6 valve set must be located as close to the burner as possible to minimize the retained CNCG volume from these isolation valves to the burner.

If the volume of CNCG that is retained is small and the piping system has the mechanical integrity to sustain a burn back after the isolation valves shut, then purging of the piping from the isolation valves to the burner is not necessary. Not purging the line avoids the possibility of water introduction to the furnace if steam is used for purging.

There are, however, system designs and maintenance safety issues that make purging of this piping run an attractive consideration; for example, large CNCG systems that have a substantial volumetric capacity in this last piping leg. Section 5.2.3, Piping System and Auxiliary Equipment, discusses line sloping, steam supply requirements, and insulating and heat tracing waste gas lines. An important part of this concept is the use of a burner design that is drainable, that is, a burner that cannot retain liquid. The purge must be done immediately after firing the CNCG system is terminated, while the piping is still hot, and with the igniter in service.

If steam purging is used, special attention must be given to keeping the steam free of condensate, thus avoiding introduction of water into the furnace. A steam line that is only occasionally used has a high probability of containing condensate and therefore injecting that condensate into the CNCG piping when the steam line is opened. The system design and operation must ensure that the purging steam is dry. As an alternative to steam, another inert gas can be used as a purging medium. For any purging medium (steam or an inert gas), the purge should displace the volume of gas contained in the piping between the last isolation valve and the furnace.

A flame arrester is located in the CNCG line as close to the burner as possible. The flame arrester physical location must be convenient for isolation and maintenance.

5.6.2 Operation

The CNCG/SOG thermal oxidation system is put into service from a local panel board by and operator who is in contact with the control room. Discontinuing thermal oxidation under normal circumstances is also done locally.

The CNCG transport system is put into operation with branch line isolation valve CG1 closed and vent valve CG2 open. At this point the double block and bleed CNCG valves, CG4, CG5 and CG6, are shut meaning the shutoff valves are closed and the bleed valve (providing vent and drain service) is open.

Next, the steam purge and preheat valves, S5, S6 and S7, are opened along with the vent/drain valve(s), CG7. This provides preheating of the CNCG line from the branch isolation valve outside of the boiler building to the vicinity of the burner. The branch valve CG1 remains closed. Admission of steam preheats the line and exits through the vent/drain.

Adequate preheating of the line will be determined by an operator observing the temperature indicator on the DCS. Once the line between the CG1and CG4 is heated, the preheat steam is shut off, the branch valve CG1 is opened and vent CG2 is closed allowing gas to be vented out of the second vent, CG7. Upon satisfying all permissives, the final gas block and bleed valves are opened, vent CG7 is closed and CNCG gases will be admitted to the furnace for thermal oxidation.

For a normal shut down, CNCG shutoff valves CG4 and CG6 and branch valve CG1 are closed, and both vent valves, CG7 and CG2, are opened as is bleed valve CG5. In addition, steam purge is immediately initiated. After adequate time for thorough purging, the steam purge is shut off.

Table 5 shows the actions that constitute a burner shutdown, both MFT and ESP. The valve positions for “normal operation” and “fail” status are also shown. If an ESP is activated, a MFT will be exercised as well as isolating all steam and water sources. An ESP will not initiate automatic purging of the CNCG line to the burner.

Table 5 Valve status and Actions at MFT and ESP; Figures 5 and 6

Valve #	Description	MFT	ESP	Operating status	Fail status
S1	EJECTOR STEAM BLOCKVALVE	NA	NA	OPEN	OPEN
S2	EJECTOR STEAM BLEED VALVE	NA	NA	CLOSE	CLOSE
S3	EJECTOR STEAM BLOCK VALVE	NA	NA	OPEN	OPEN
S4	STEAM EJECTOR CNTR VALVE	NA	NA	MOD	LAST P
S5	PURGE STEAM BLOCK VALVE	OPEN	OPEN	CLOSE	CLOSE
S6	PURGE STEAM BLEED VALVE	CLOSE	CLOSE	OPEN	OPEN
S7	PURGE STEAM BLOCK VALVE	OPEN	OPEN	CLOSE	CLOSE
S8	PURGE STEAM BLOCK VALVE	OPEN	OPEN	CLOSE	CLOSE
S9	PURGE STEAM BLEED VALVE	CLOSE	CLOSE	OPEN	OPEN
S10	PURGE STEAM BLOCK VALVE	OPEN	OPEN	CLOSE	CLOSE
CG1	CNCG SHUT OFF VALVE	CLOSE	CLOSE	OPEN	CLOSE
CG2	CNCG MAIN VENT VALVE	OPEN	OPEN	CLOSE	OPEN
CG3	ALTERNATE SYSTEM SHUTOFF	NA	NA	CLOSE	NA/CLOSE
CG4	BURNER SHUT OFF VALVE	CLOSE	CLOSE	OPEN	CLOSE
CG5	BURNER VENT VALVE	OPEN	OPEN	CLOSE	OPEN
CG6	BURNER SHUT OFF VALVE	CLOSE	CLOSE	OPEN	CLOSE
CG7	CNCG VENT VALVE	OPEN	OPEN	CLOSE	OPEN
SG1	SOG SHUT OFF VALVE	CLOSE	CLOSE	OPEN	CLOSE
SG2	SOG MAIN VENT VALVE	OPEN	OPEN	CLOSE	OPEN
SG3	ALTERNATE SYSTEM SHUTOFF	NA	NA	CLOSE	NA/CLOSE
SG4	BURNER SHUTOFF VALVE	CLOSE	CLOSE	OPEN	CLOSE
SG5	BURNER VENT VALVE	OPEN	OPEN	CLOSE	OPEN
SG6	BURNER SHUT OFF VALVE	CLOSE	CLOSE	OPEN	CLOSE
SG7	SOG VENT VALVE	OPEN	OPEN	CLOSE	OPEN
D1	AIR CONTROL DAMPER	LAST P	CLOSE	MOD	LAST P
IGNITER GT	IGNITER GAS TRAIN	CLOSE	CLOSE	OPEN	CLOSE

GREY BLOCK OPERATIONS ARE ACTIVATED VIA A TIMER TO ALLOW FOR PURGING OF THE CNCG AND SOG LINES.

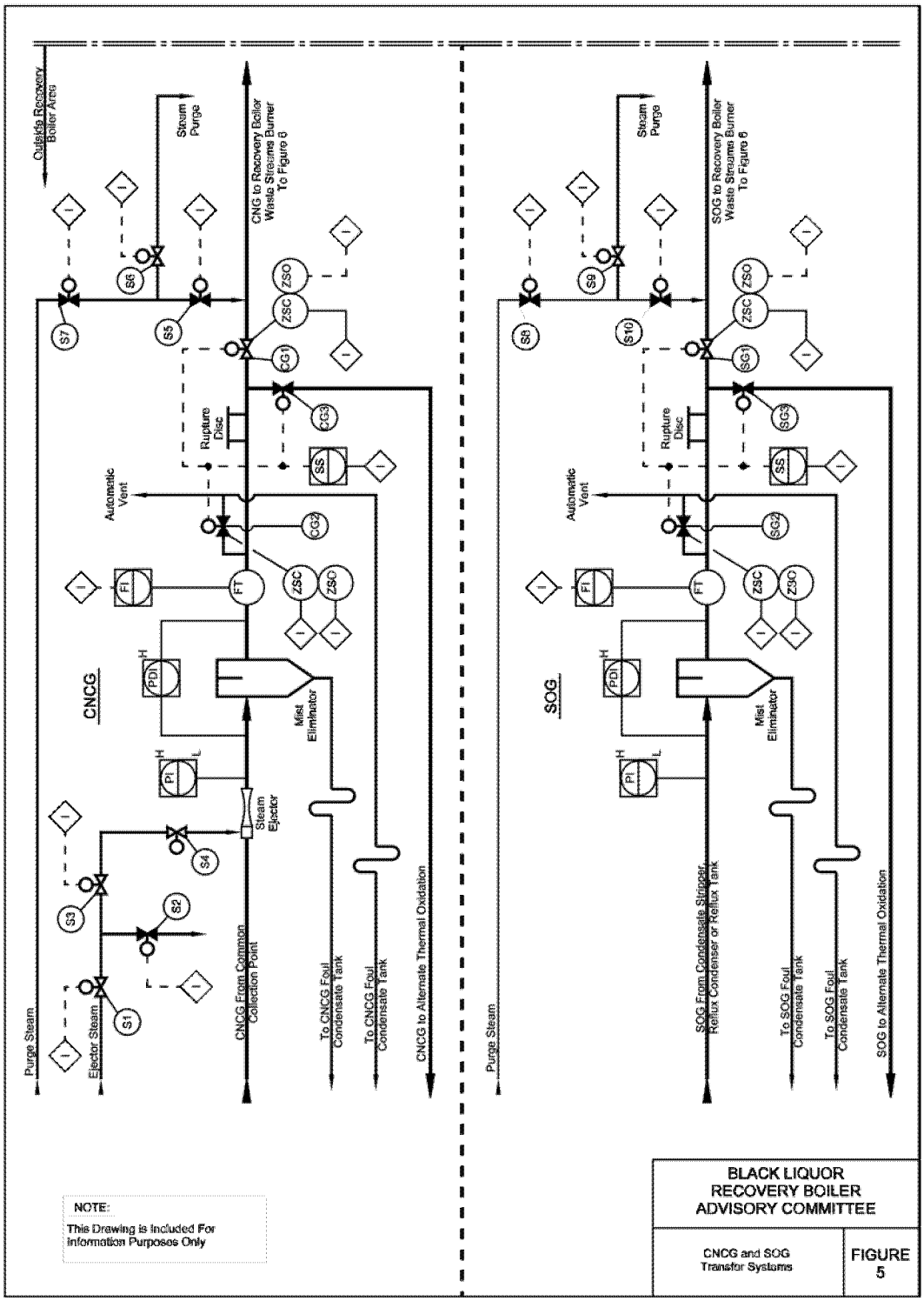

Figure 5 CNCG and SOG Transfer Systems.

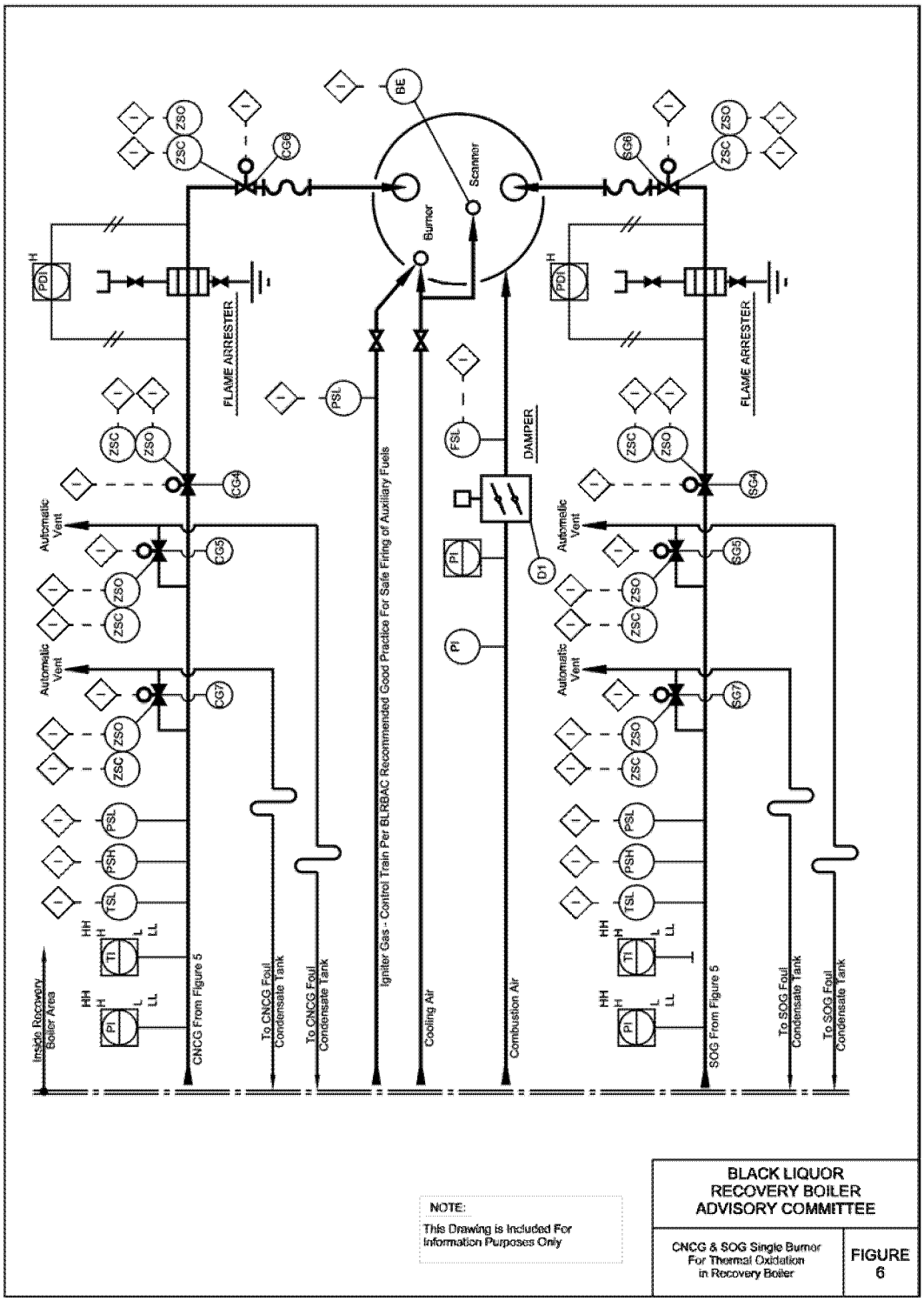

Figure 6 CNCG & SOG Single Burner for Thermal Oxidation in Recovery Boiler.

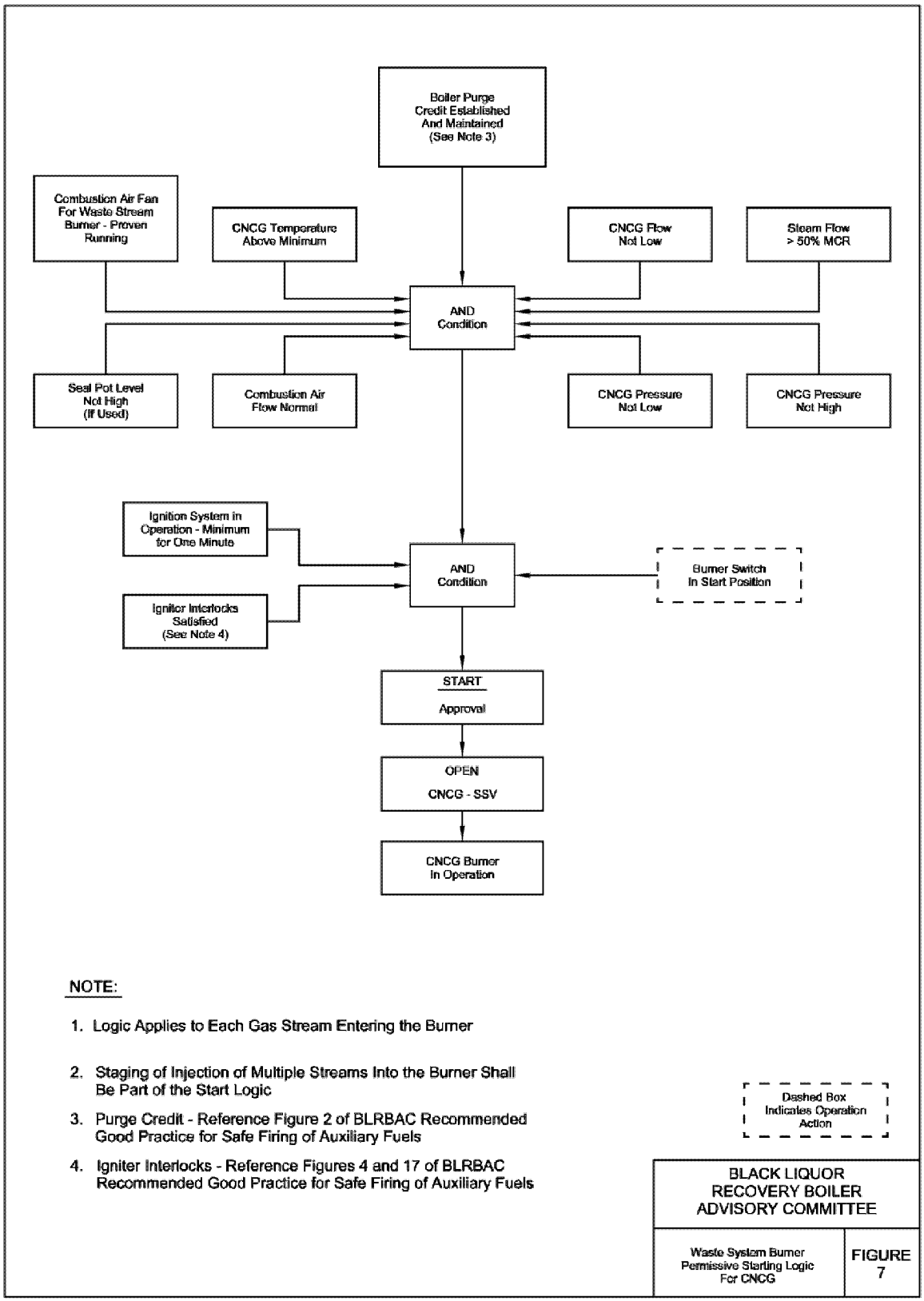

Figure 7 Waste System Burner Permissive Starting Logic for CNCG

Table 6 Logic Explanation Chart for Figure 7 Permissive Starting Logic - Waste Streams Burner

LOGIC BLOCK	PURPOSE	HAZARD PROTECTED
Boiler Purge Credit Maintained (From Figure 2 Common Permissive Starting Logic in Safe Firing of Auxiliary Fuel Guidelines).	Ensure firing permissive.	Prevent introduction of NCGs while boiler is not being fired.
Steam Flow >50% MCR.	Ensure furnace combustion is stable.	Explosion or improper oxidation of gases. This may require a higher steam flow based upon CNCG requirements.
Combustion air fan for waste stream burner - proven running.	Ensure proper combustion air to burner.	Potential explosion from improper or impaired air flow.
CNCG/SOG temperature above minimum.	Ensure proper gas properties.	Introduction of liquid.
CNCG/SOG pressure not high.	Ensure proper gas properties and injection at proper velocity.	
CNCG/SOG pressure not low.	Ensure proper gas properties and emitted at proper velocity.	
CNCG/SOG flow not low	Ensure proper gas velocity	Avoid plugged nozzle
Seal pot level not high.	Prevent liquid back up.	Possible explosion due to moisture introduction to boiler
Combustion air flow normal.	Ensure air flow through burner.	Potential explosion from improper or impaired air flow.
Combustion air pressure normal.	Ensure proper combustion air properties.	Potential explosion from improper or impaired combustion air supply.
Ignition system in operation - minimum of one minute.	Ensure stable ignition system operation.	Possible explosion due to CNCG/SOG gas burner introduction cycling.
Burner switch in start position.	Allow start after interlocks satisfied.	By operator.
Igniter interlocks satisfied.	Interlocks from Auxiliary Fuel Guidelines 4 and 17.	Explosion from improper or delayed ignition.
Start approval.	All burner/igniter interlocks satisfied.	
Energize CNCG/SOV SSV.	Admit gas to furnace.	
CNCG/SOG burner in operation.	Verify oxidation.	Operator function

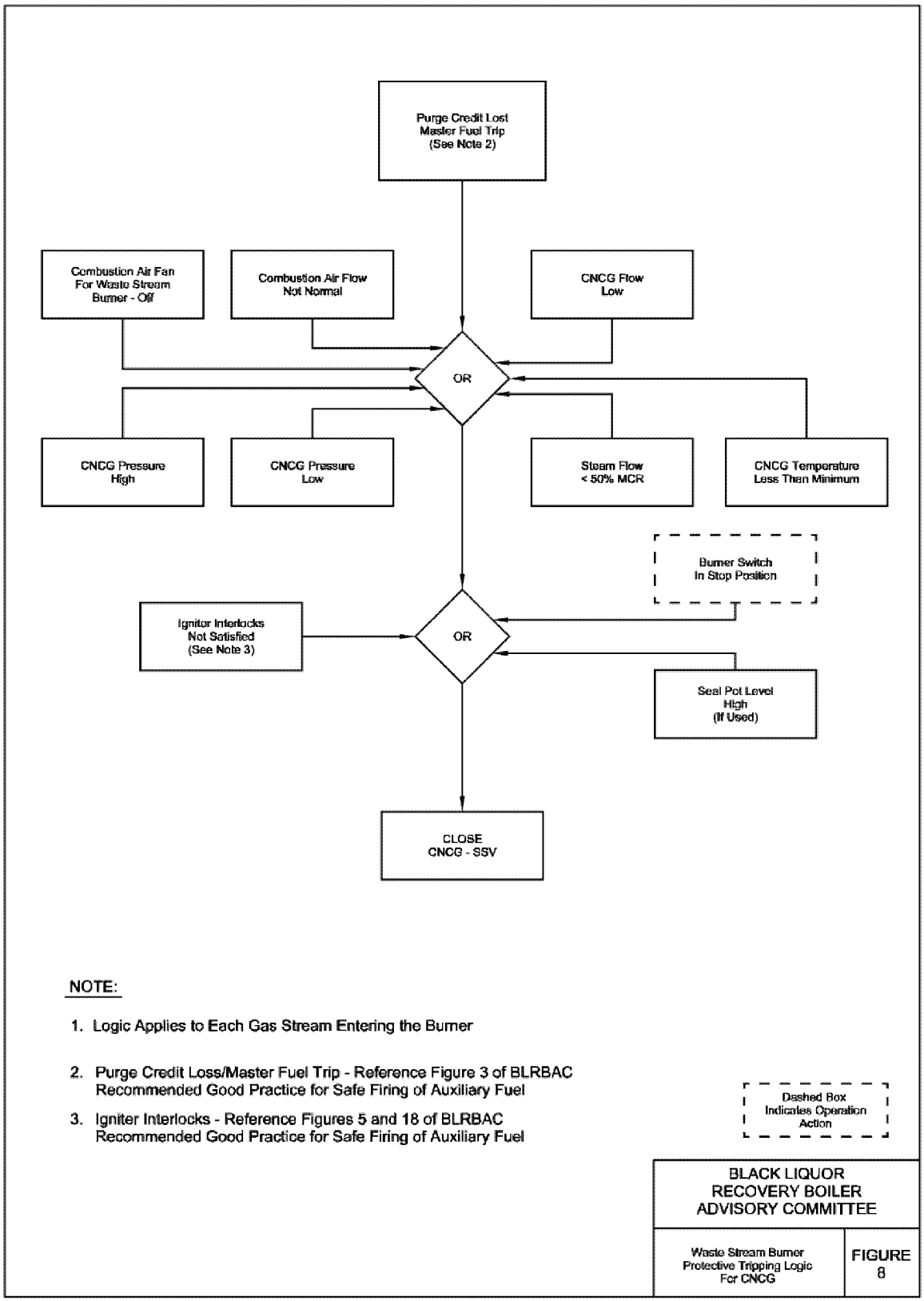

Figure 8 Waste Stream Burner Protective Tripping Logic for CNCG.

Table 7 Logic Explanation Chart for Figure 8 Protective Tripping Logic - Waste Stream Burner

LOGIC BLOCK	PURPOSE	HAZARD PROTECTED
Boiler Purge Credit Lost Master Fuel Trip (From Figure 2 Common Permissive Starting Logic in Safe Firing of Aux Fuel Guidelines).	Stop CNCG introduction when boiler firing permissives not met.	Prevent introduction of CNCG while boiler is not being fired.
Steam Flow <50% MCR.	Stop CNCG firing when firing rate below minimum.	Explosion or improper oxidation of gases.
Combustion air flow not normal.	Stop CNCG firing in the event of air flow upsets to burner.	Potential explosion from improper or impaired air flow.
Combustion air fan for waste stream burner not running.	Stop CNCG firing when no combustion air to burner.	Potential explosion from improper or impaired air flow.
CNCG/SOG pressure low or high.	Ensure proper gas properties and injection at proper velocity.	Flash back up piping or poor ignition beyond igniter.
CNCG/SOG flow low	Ensure proper velocity	Plugged nozzle
CNCG/SOG temperature low.	Ensure proper gas properties.	Introduction of liquid.
Combustion air pressure not normal.	Ensure proper combustion air properties.	Potential explosion from improper or impaired combustion air supply.
Igniter Interlocks not satisfied.	Interlocks from Auxiliary Fuel Guidelines 4 and 17 not met.	Explosion from improper or delayed ignition.
Seal pot level high.	Prevent liquid back up.	Possible explosion due to moisture introduction to boiler.
Burner switch in stop mode.	Prevent firing of burner.	Operator action.
Close CNCG/SOG SSV.	Shutdown CNCG/SOG burner.	

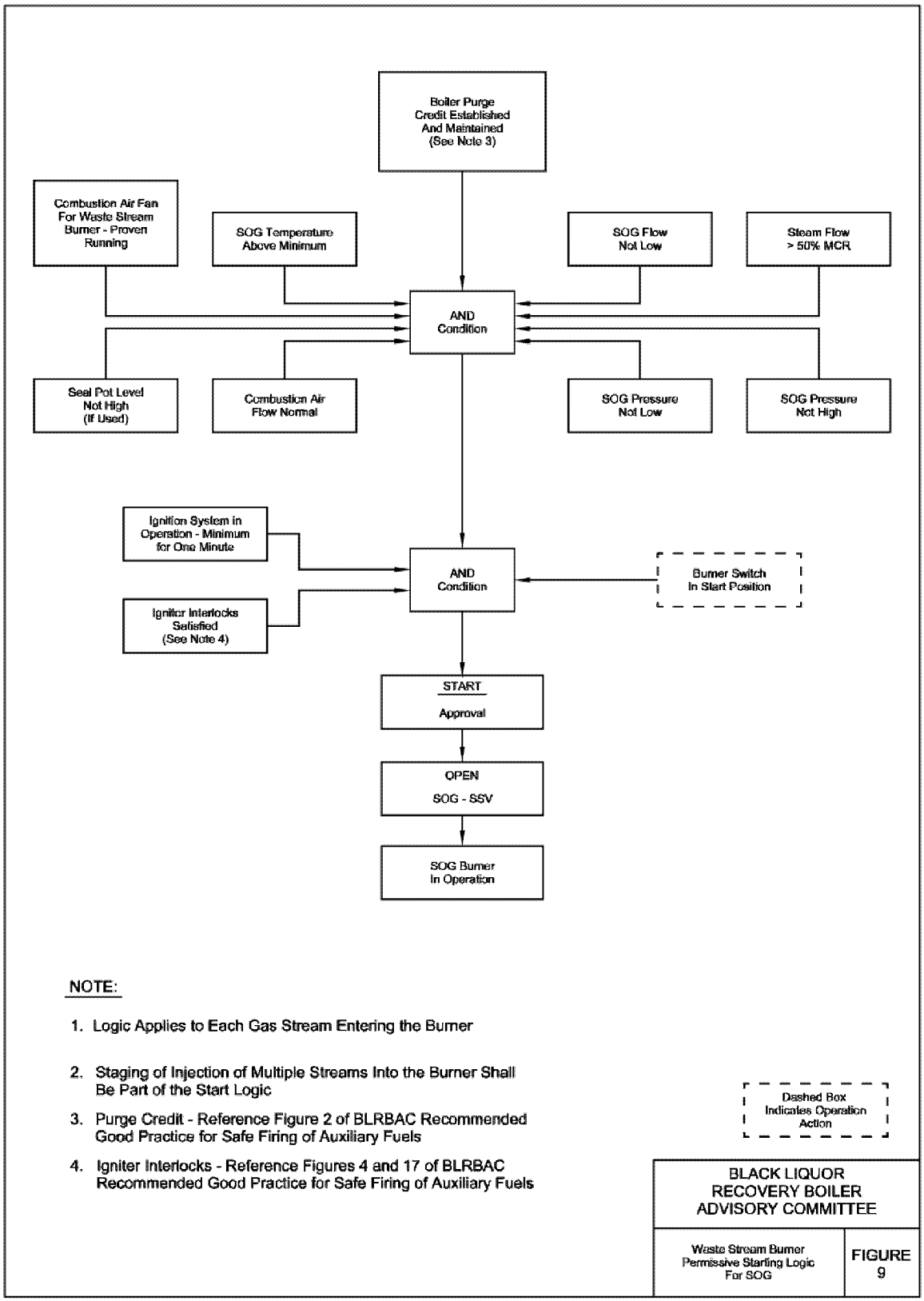

Figure 9 Waste Stream Burner Permissive Starting Logic for SOG.

Table 8 Logic Explanation Chart for Figure 9 Permissive Starting Logic for SOG - Waste Streams Burner

LOGIC BLOCK	PURPOSE	HAZARD PROTECTED
Boiler Purge Credit Maintained (From Figure 2 Common Permissive Starting Logic in Safe Firing of Auxiliary Fuel Guidelines).	Ensure firing permissive.	Prevent introduction of SOG while boiler is not being fired.
Steam Flow >50% MCR.	Ensure furnace combustion is stable.	Explosion or improper oxidation of gases. This may require a higher steam flow based upon SOG requirements.
Combustion air fan for waste stream burner - proven running.	Ensure proper combustion air to burner.	Potential explosion from improper or impaired air flow.
SOG temperature above minimum.	Ensure proper gas properties.	Introduction of liquid.
SOG pressure not high.	Ensure proper gas properties and injection at proper velocity.	
SOG pressure not low.	Ensure proper gas properties and emitted at proper velocity.	
Seal pot level not high.	Prevent liquid back up.	Possible explosion due to moisture introduction to boiler
SOG flow not low.	Ensure SOG line velocity is adequate	Prevent flame propagation back through SOG line
Combustion air flow normal.	Ensure air flow through burner.	Potential explosion from improper or impaired air flow.
Ignition system in operation - minimum of one minute.	Ensure stable ignition system operation.	Possible explosion due to SOG gas burner introduction cycling.
Burner switch in start position.	Allow operator to start burner <u>after</u> all other interlocks satisfied.	By operator.
Igniter interlocks satisfied.	Interlocks from Auxiliary Fuel Guidelines 4 and 17.	Explosion from improper or delayed ignition.
Start approval.	All burner/igniter interlocks satisfied.	
Energize SOV SSV.	Admit gas to furnace.	
SOG burner in operation.	Verify oxidation.	Operator function.

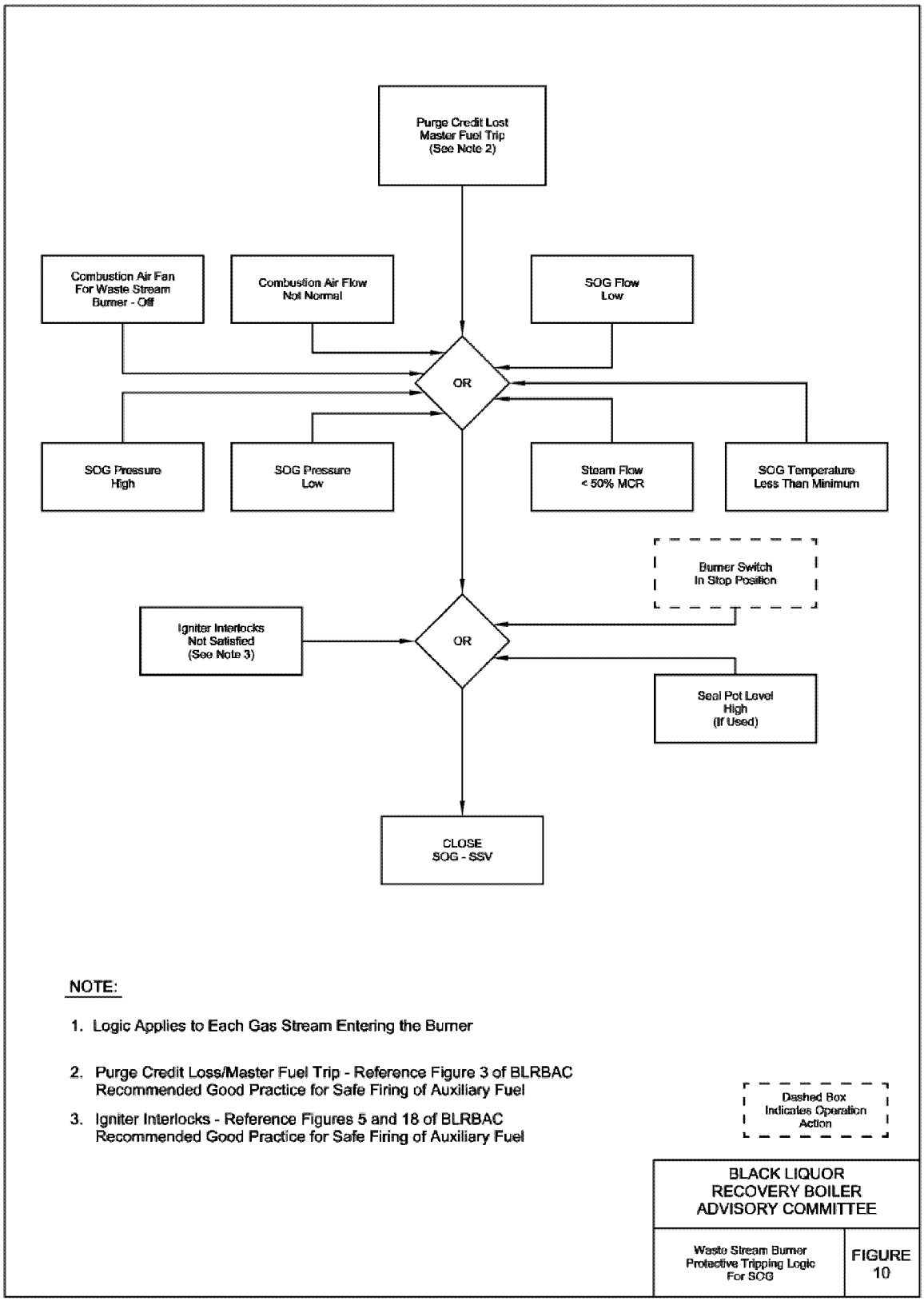

Figure 10 Waste Stream Burner Protective Tripping Logic for SOG.

Table 9 Logic Explanation Chart for Figure 10 Protective Tripping Logic for SOG - Waste Stream Burner

LOGIC BLOCK	PURPOSE	HAZARD PROTECTED
Boiler Purge Credit Lost Master Fuel Trip (From Figure 3 Common Permissive Starting Logic in Safe Firing of Aux Fuel Guidelines).	Stop SOG introduction when boiler firing permissives not met.	Prevent introduction of SOG while boiler is not being fired.
Steam Flow <50% MCR.	Stop SOG firing when firing rate below minimum.	Explosion or improper oxidation of gases.
Combustion air flow not normal.	Stop SOG firing in the event of air flow upsets to burner.	Potential explosion from improper or impaired air flow.
Combustion air fan for waste stream burner not running.	Stop SOG firing when no combustion air to burner.	Potential explosion from improper or impaired air flow.
SOG pressure low or high.	Ensure proper gas properties and injection at proper velocity.	Flash back up piping or poor ignition beyond igniter.
SOG temperature low.	Ensure proper gas properties.	Introduction of liquid.
SOG flow low.	Ensure SOG line velocity is adequate.	Prevent flame propagation back through SOG line.
Igniter Interlocks not satisfied.	Interlocks from Auxiliary Fuel Guidelines 5 and 18 not met.	Explosion from improper or delayed ignition.
Seal pot level high.	Prevent liquid back up.	Possible explosion due to moisture introduction to boiler.
Burner switch in stop mode.	Prevent firing of burner.	Operator action.
Close SOG SSV.	Shutdown SOG burner.	

CHAPTER 6 LIQUID WASTE STREAMS BLENDED WITH BLACK LIQUOR

6.1 Introduction

In the arena of thermal oxidation of liquid waste streams, presently the most common method for thermal oxidation is blending the waste stream into black liquor. The most common stream is spent acid from ClO_2 or from tall oil. The second most common stream is soap. These two streams (spent acid and soap) represent the two general categories of streams covered by this guideline: those with a high water content and those that are waterless. In addition, this chapter addresses blending methanol, secondary sludge, tall oil, and turpentine (or red oil) with black liquor.

The system designer should take into consideration features such as limit switches, "fail" position of valves and other safety features as appropriate.

Here are some summary comments covering these guidelines:

- The boiler operation must be stable and firing liquor at a minimum load of 50% MCR when adding waste streams. The minimum load requirement assists in ensuring stable operation.

- The waste stream must always be blended into black liquor before the refractometers to ensure that the refractometers read the stream that is being fired.

- Off-line solids testing of black liquor must be done every two hours when firing liquid waste streams.

- Adding a waste stream continuously provides better recovery furnace operation than a batch operation.

- For streams added to black liquor after final concentration, the waste streams should be metered and proportioned to the black liquor flow rate. Waste stream flows should be limited such that if the stream flows were 100% water, the black liquor solids concentration would not fall below minimum safe firing level.

- High water content streams should be added before black liquor reaches its final concentration. Waterless streams should be added after the final mix tank.

- Include a "management of change" procedure when you are designing or modifying a system to blend a waste stream with black liquor.

- Effect of waste streams on refractometers:
  - Waste streams can coat prisms.
  - Soap lowers the refractive index.
  - Un-neutralized spent acid lowers the refractive index due to precipitation of dissolved solids. The refractometer does not "see" suspended solids.
  - Turpentine or red oil lowers the refractive index.

- AF&PA Recovery Boiler Reference Manual, Volume III section 5.2.1.4, is a good reference and was used in preparing this document.

6.2 Methanol

Definition: Liquid methanol is condensed from stripper off gas (SOG). SOG consists of approximately 50 percent methanol vapor by weight. SOG can be converted to a liquid of high methanol concentration and heating value through the process of methanol rectification. This liquid typically has a methanol content of 50 percent to 80 percent by weight, but can range from 30% to 90%. Specific gravity of 100% methanol is 0.79. Methanol from SOG usually contains TRS, terpenes, and other contaminants that make it noxious.

Safeguards for combining methanol with the black liquor stream to the recovery boiler:

Where: Add methanol to black liquor after the point of final concentration in black liquor piping downstream of tankage including the salt cake mix tank. This will reduce the possibility of explosive gases in the vapor space in tanks.

Ensure that there is adequate mixing of methanol and black liquor. The addition should occur far enough upstream in the piping to ensure proper mixing.

If methanol is added upstream of black liquor pumps, be aware that methanol's vapor pressure at black liquor's temperature may result in flashing at the eye of the impeller, which will reduce pump capacity.

Indirect black liquor heaters should be examined for ability to hold a "pocket" of methanol vapor. Injection of methanol downstream of an indirect black liquor heater may be preferable.

Addition point <u>must</u> be upstream of refractometers.

Although methanol has some water content, it cannot be added to black liquor before final concentration is reached because evaporators are an original source of methanol. Returning methanol to the evaporators will build the concentration of methanol rather than dispose of methanol.

How: Include a "management of change" procedure when you are designing or modifying a system to blend methanol with black liquor.

Methanol flow rate must be measured to maintain a safe black liquor to methanol ratio. A safe upper limit is 1% by volume of methanol solution due to its volatile nature and potential instability.

Blend with black liquor using in-line mixing.

Methanol should be fed continuously to provide consistent refractometer readings.

Be aware of the possibility of methanol build-up in black liquor piping high points.

Methanol must be isolated with a double isolation valve arrangement located near the methanol injection point in the black liquor line. This location minimizes residual methanol drainage into black liquor after the valves shut.

Interlocks: Boiler must be operated in accordance with the Safe Firing of Black Liquor Guidelines.

Methanol can only be added to the liquor system only when the operation of the recovery boiler is stable and firing liquor at a minimum load of 50% MCR.

When safe firing system trips the black liquor system feed, the methanol feed is isolated by stopping the pump and automatically closing both isolation valves on the methanol feed line. Both stopping the pump and closing valves will ensure positive isolation of methanol.

Methanol feed must be stopped whenever black liquor is recirculated rather than fired to prevent build up of methanol and resulting vapors in black liquor and in liquor storage tanks.

Do not blend methanol in a liquor firing system that continuously recirculates a portion of the liquor stream to a tank. A liquor system that continuously recirculates a portion of the liquor stream to a tank will suffer from build up of the methanol and resulting vapors in the black liquor and in liquor storage tanks.

Methanol feed must be stopped at the low black liquor solids alarm point. Waste stream addition could be the cause of the low solids alarm, so a reasonable first step when solids are low is to stop waste stream addition.

A minimum black liquor solids content for allowing methanol introduction should be determined and used as a starting permissive for methanol incineration. This permissive can avoid a low solids alarm caused by a drop in refractometer liquor solids due to methanol addition.

Starting and tripping logic diagrams for methanol are included at the end of this methanol section (see Figures 11 and 12).

Measurements: The methanol delivery system must have control room indication when methanol is being introduced.

Flow rate should be measured.

Consider measuring methanol concentration and isolating methanol line if methanol concentration indicates increased water presence.

Consider having high and low flow alarms.

Impacts of combining methanol with the black liquor stream to the recovery boiler:

Heating Value: Higher heating value for 100% methanol is about 9200 Btu/lb.

Volatility: Methanol's boiling point is 148°F. Black liquor sampling upstream of methanol addition will avoid flashing methanol in sample.

Corrosiveness: Corrosive; use stainless steel.

Combustion: Flash point from 54°F (closed cup) as compared to 100°F to 150°F for fuel oil.

Solids Measurement: When firing methanol with black liquor, the black liquor refractive index may decrease, causing an apparent lower solids measurement. The decrease would be due to methanol having a refractive index lower than black liquor. Off-line testing will not be affected by methanol (but there will be an odor during off-line testing.) Operators and Instrument Technicians must understand the effect of methanol on the refractive index and off-line testing. The system must not compromise the minimum solids liquor divert recommended by Safe Firing of Black Liquor.

An off-line solids measurement test must be conducted immediately after introduction or removal of methanol and at 2-hour intervals any time methanol is blended into black liquor. Off-line testing must recognize the odor potential of methanol. After removal of methanol, a second test must be done within 2 hours. The last test provides data for re-establishing correct on-line solids readings.

Methanol may accelerate build-up on the refractive lens resulting in inaccurate readings. The prism wash frequency may increase.

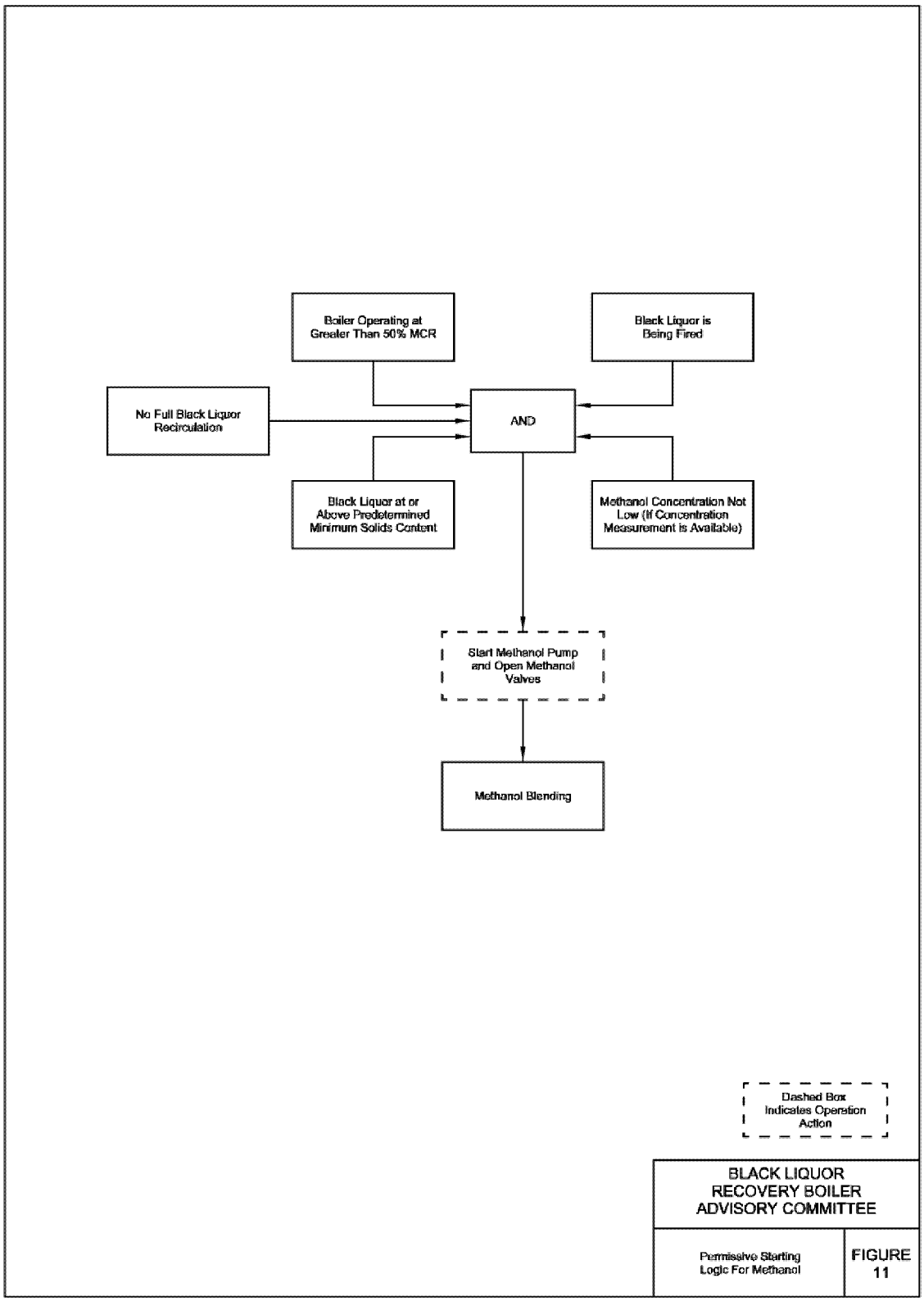

Figure 11 Permissive Starting Logic for Methanol.

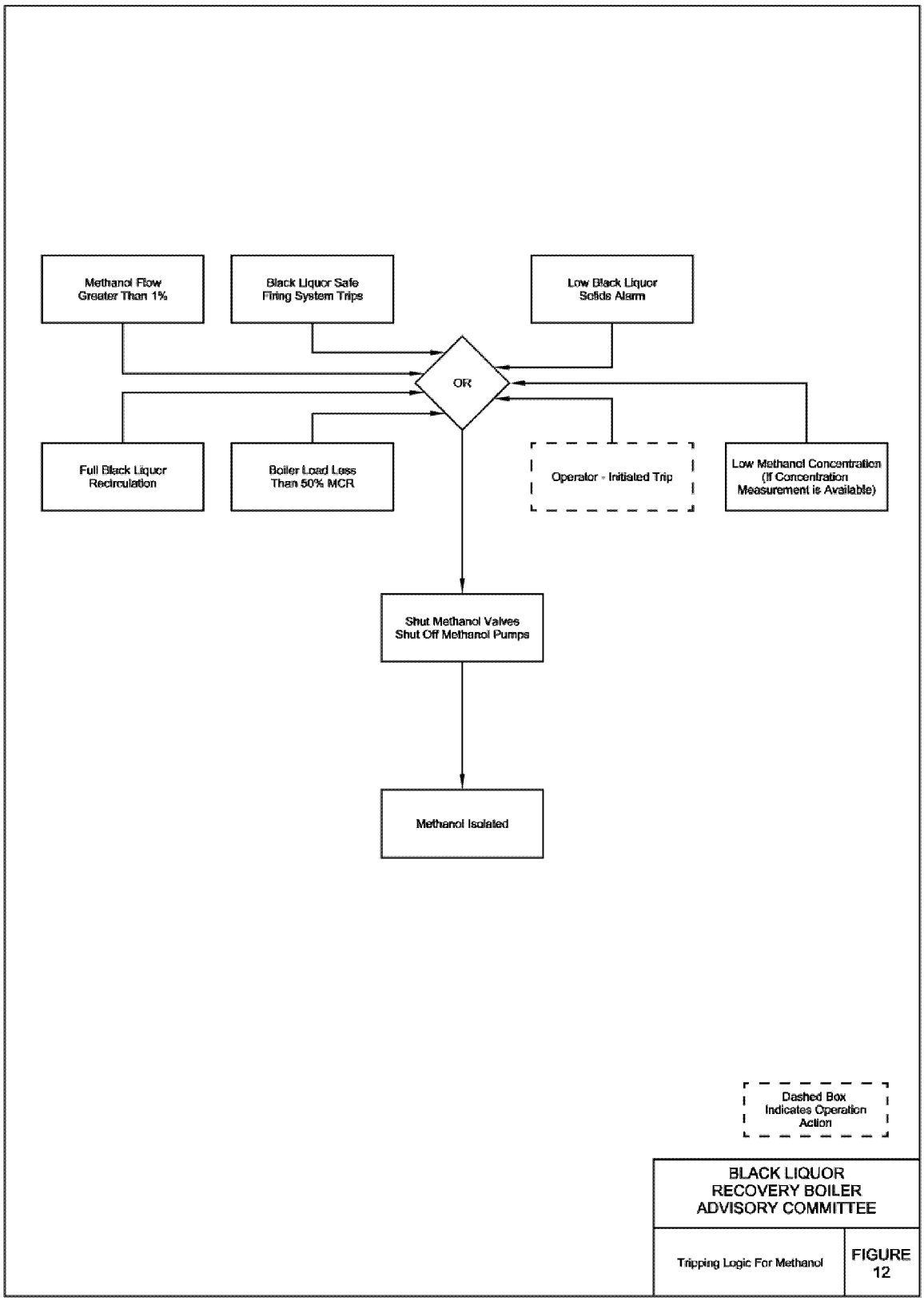

Figure 12 Tripping Logic for Methanol.

6.3 Secondary Sludge

Definition: Secondary sludge is the waste residue resulting from the biological treatment of wastewater. The treatment of wastewater is usually a two stage process; the first stage (primary treatment) removes suspended solids and fibrous material. The wastewater is then passed on to the secondary treatment where bacteria digest organic material in the wastewater. The residue from the treatment forms a sludge that has a very high moisture content (>90%). The sludge can have a portion of the moisture mechanically removed (i.e. by centrifuge) prior to introduction into the black liquor system.

Safeguards for combining secondary sludge with the black liquor stream to the recovery boiler:

Where: Secondary sludge shall only be introduced into the black liquor system prior to the point of final concentration. The preferred location for introduction is prior to or into the evaporator system.

How: Include a "management of change" procedure when you are designing or modifying a system to blend secondary sludge with black liquor.

Secondary sludge may be introduced into the black liquor system as a separate stream upstream of the evaporators, between evaporator effects, or upstream of the concentrators. Sludge should be introduced into a location that provides adequate blending with the black liquor. Sludge blending with black liquor should be on a continuous basis as opposed to batch-process to provide more uniform and predictable performance.

A typical secondary sludge feed rate is approximately 2% of the black liquor solids. This small quantity is not expected to create significant volatility, corrosiveness, or combustion problems in the recovery boiler furnace.

Interlocks: Since the addition of secondary sludge may only be added prior to the point of final concentration, use and design of interlocks will be up to the user.

Measurement: The quantity of secondary sludge delivered to the black liquor system should be monitored.

The secondary sludge delivery system must have control room indication when sludge is being introduced.

Impacts of combining secondary sludge with the black liquor stream to the recovery boiler:

Heating value of liquor: Introducing the sludge in to the black liquor system upstream of the final evaporation stages will minimize the sludge's effect on as-fired heating value and dilution of black liquor solids levels.

Volatility: Based on limited information, the addition of secondary sludge to the black liquor system should not affect the liquor volatility.

Corrosiveness: The end user shall determine the impact of secondary sludge on black liquor chemistry to identify the potential for increased corrosion of boiler components. Based on limited information, secondary sludge should not create additional corrosion mechanisms in the black liquor system. Corrosion resistant materials already in use in black liquor systems should be suitable for the dilute mixture of secondary sludge and black liquor.

Combustion: Based on limited information, the addition of secondary sludge to the black liquor upstream of the evaporators may have a favorable impact due to a slight increase in liquor heating value.

Solids measurement: Secondary sludge may accelerate the buildup on the optical components of the solids measuring devices (refractometers), requiring more frequent cleaning and calibration.

6.4 Soap

Definition: Black liquor soap is a mixture of resin and fatty acids that is separated from weak and intermediate black liquors. It is removed to avoid scaling and foaming in the evaporators and concentrators. Soap may have commercial value. Softwoods contain more soap than hardwoods, which necessitates soap removal.

Safeguards for combining soap with the black liquor stream to the recovery boiler:

Where: Add soap to black liquor after the point of final concentration.

To ensure adequate mixing, consider adding the soap to the suction of the black liquor fuel pumps. If not added to the black liquor pump suction, the addition should occur far enough upstream in the piping to ensure proper mixing. It is critical that soap be prevented from separating from the black liquor after mixing. Soap should not be introduced upstream of a non-agitated tank.

Addition point must be upstream of refractometers.

How: Include a "management of change" procedure when you are designing or modifying a system to blend soap with black liquor.

Blend with black liquor using in-line mixing.

Soap should be fed continuously to provide consistent boiler operation and refractometer readings.

Soap must be isolated with a double isolation valve arrangement located near the soap injection point in the black liquor line. This location minimizes residual soap drainage into black liquor after the valves shut.

Soap should be metered relative to BL to maintain a constant soap concentration. This might be accomplished with an in-line device such as a separate density meter to verify the quality of soap to water content.

The upper limit on soap firing should be established by assuming that if the soap flow were 100% water, the black liquor solids concentration would not fall below minimum safe firing level.

Interlocks: Boiler must be operated in accordance with the Safe Firing of Black Liquor Guidelines.

Soap can only be added to the liquor system when the operation of the recovery boiler is stable and firing liquor at a minimum load of 50% MCR.

When safe firing system trips the black liquor system feed, the soap feed is isolated by automatically closing both isolation valves on the soap feed line. The soap pump can continue to run, allowing soap to recirculate when not being blended with black liquor.

Soap feed must be stopped whenever black liquor is recirculated rather than fired to prevent build up of soap in liquor storage tanks.

Soap blending in a liquor firing system that continuously recirculates a portion of the liquor stream to tank(s) must have continuous agitation in the tank(s) to avoid separation of soap and liquor.

Soap feed must be stopped at the low black liquor solids alarm point. Waste stream addition could be the cause of the low solids alarm, so a reasonable first step when solids are low is to stop waste stream addition.

A minimum black liquor solids content for allowing soap introduction should be determined and used as a starting permissive for soap incineration. This permissive can avoid a low solids alarm caused by a drop in refractometer liquor solids due to soap addition.

Starting and tripping logic diagrams for soap are included at the end of this soap section (see Figures 13 and 14).

Measurement: The soap delivery system must have control room indication when soap is being introduced.

The soap delivery system should have either a flow meter or a delivery system design that will maintain soap in proportion to the liquor flow.

Consider using an in-line device to determine the amount of water in soap. Soap density measurement is a proven method of monitoring water content.

Impacts of combining soap with the black liquor stream to the recovery boiler:

Heating Value: Soap has a greater heating value than black liquor.

Corrosiveness: Not corrosive.

Volatility: Low

Combustion: Addition of soap will increase the liquor HHV. Soap burns more aggressively than black liquor resulting in a hotter fire and smaller bed. Operators must adjust to the burning characteristics of soap.

Solids Measurement: When firing soap with black liquor, the black liquor refractive index will decrease, causing an apparent lower solids measurement. The decrease would

be due to soap having a refractive index lower than black liquor. Off-line testing will include soap solids as part of black liquor solids so the results will be higher than actual black liquor solids content. Operators and Instrument Technicians must understand the effect of soap on the refractive index and off-line testing. The system must not compromise the minimum solids liquor divert recommended by Safe Firing of Black Liquor.

An off-line solids measurement test must be conducted immediately after introduction or removal of soap and at 2-hour intervals any time soap is blended into black liquor. Addition of soap can give a false high reading for the off-line solids measurement field test. After removal of soap, a second test must be done within 2 hours. The last test provides data for re-establishing correct on-line solids readings.

The soap can coat the refractive lens resulting in inaccurate readings. The prism wash frequency will increase.

Increasing the quality of soap mixing will cause fewer problems with the refractometers.

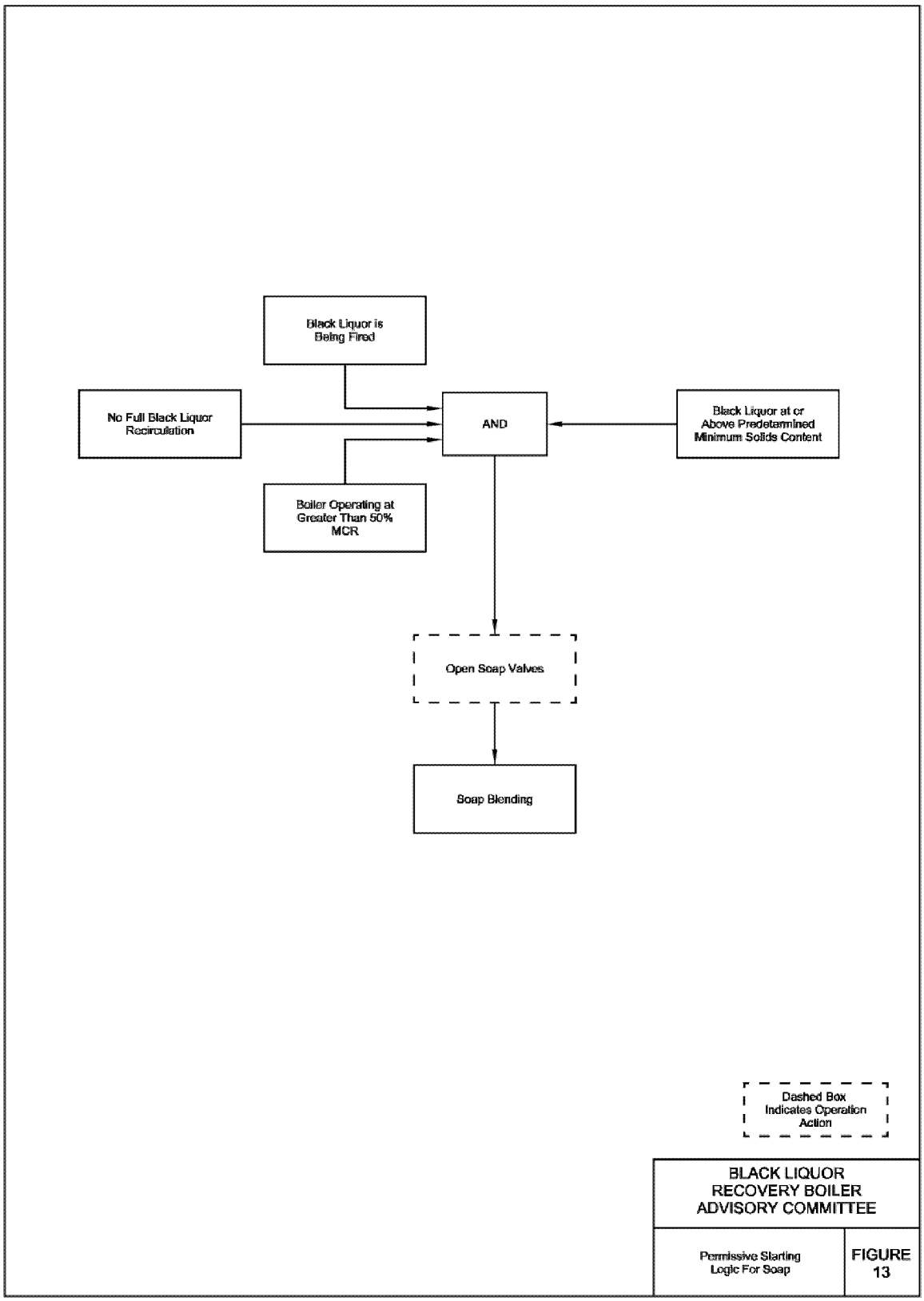

Figure 13 Permissive Starting Logic for Soap.

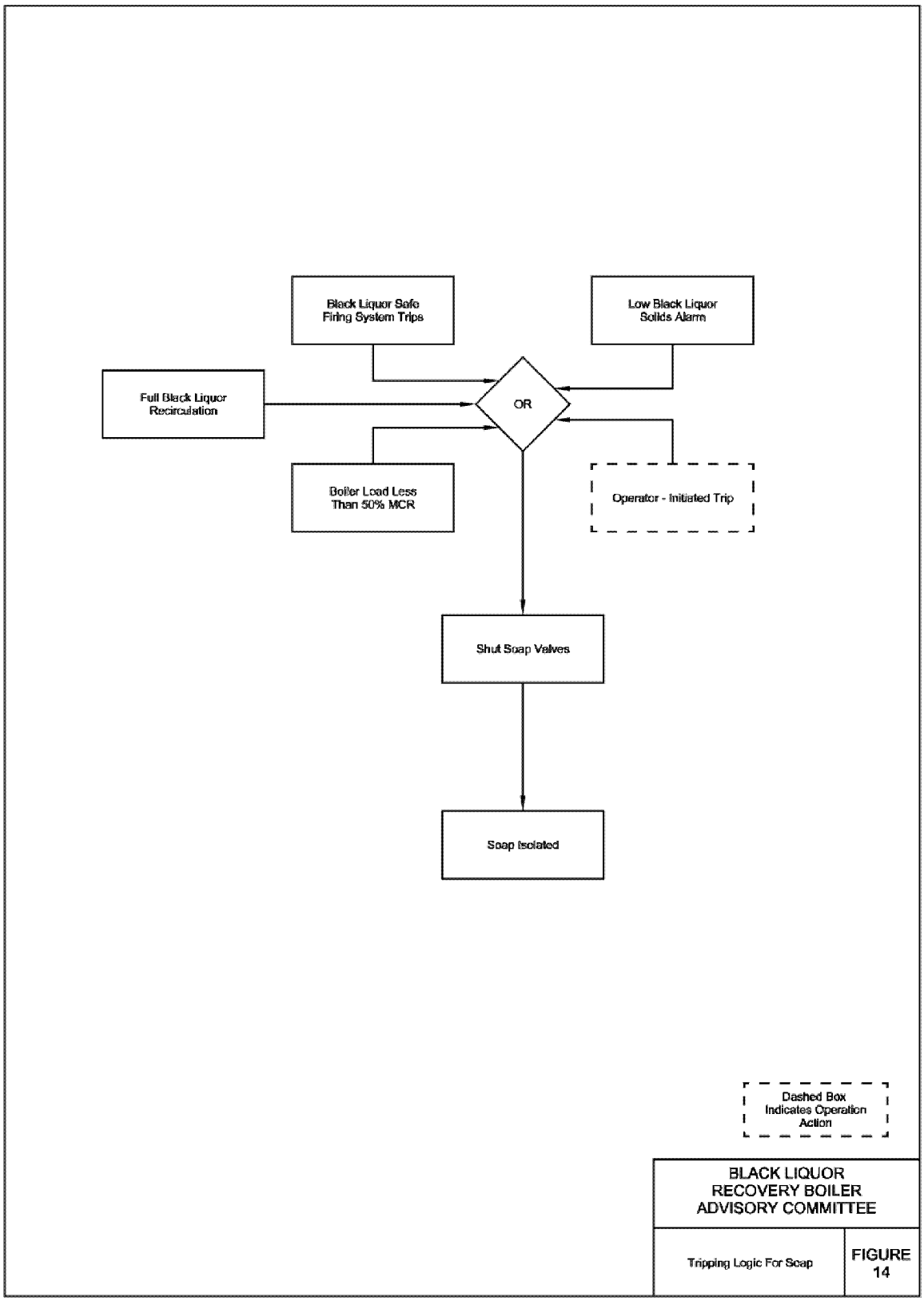

Figure 14 Tripping Logic for Soap.

6.5 Spent Acid from ClO_2 and Tall Oil Brine

Definitions: The aqueous solution by-product from the acidulation of tall oil soap to tall oil, usually consisting primarily of sodium sulfate in water solution. ClO_2 spent acid is the effluent from a ClO_2 generator. It is an aqueous solution containing Na_2SO_4, H_2SO_4, NaCl and $NaClO_3$.

The term "spent acid" will be used to refer to both tall oil brine and ClO_2 spent acid.

Safeguards for combining spent acid with the black liquor stream to the recovery boiler:

Where: Due to water content in this stream, the preferred feed point is prior to the point of final concentration.

To avoid possible evaporator scaling, consider adding the spent acid to the 50% black liquor feed to the concentrators or direct contact evaporator.

How: Include a "management of change" procedure when you are designing or modifying a system to blend spent acid with black liquor.

Neutralize the spent acid before it is added to the black liquor. This will help prevent the black liquor viscosity from increasing and will prevent the formation of H_2S. Neutralization should be to a minimum pH of 10.5.

Tanks in which tall oil spent acid is added to the black liquor should be vented to the NCG system to prevent escape to the atmosphere of any toxic gases formed.

If spent acid is added after final concentration, it should be added continuously to provide consistent refractometer readings.

Spent acid added after the point of final concentration must be isolated with a double isolation valve arrangement located near the spent acid injection point in the black liquor line. This location minimizes residual spent acid drainage into black liquor after the valves shut.

Interlocks: Boiler must be operated in accordance with the Safe Firing of Black Liquor Guidelines.

If added to weak black liquor, addition of spent acid can be independent of black liquor firing rate.

If added to concentrated black liquor after the point of final concentration, spent acid can only be admitted when the operation of the recovery boiler is stable and firing liquor at a minimum load of 50% MCR.

If added to concentrated black liquor after the point of final concentration, spent acid feed must be stopped whenever black liquor is recirculated rather than fired to prevent build up of spent acid in liquor storage tanks.

When the safe firing system trips the black liquor feed, the spent acid feed after point of final concentration is isolated by stopping the pump and automatically closing both isolation valves on the feed line. Both stopping the pump and closing valves will ensure positive isolation of spent acid.

Spent acid feed after the point of final concentration must be stopped at the low black liquor solids alarm point. Waste stream addition could be the cause of the low solids alarm, so a reasonable first step when solids are low is to stop waste stream addition.

If spent acid is added after point of final concentration, a minimum black liquor solids content for allowing spent acid introduction should be determined and used as a starting permissive for spent acid. This permissive can avoid a low solids alarm caused by a drop in refractometer liquor solids due to spent acid addition.

Starting and tripping logic diagrams for spent acid when added after the point of final concentration are included at the end of this spent acid section (see Figures 15 and 16).

Measurement: Spent acid added after point of final concentration must be measured and proportioned to black liquor flow rate.

The spent acid delivery system must have control room indication when spent acid is being introduced.

If neutralized after point of final concentration, neutralization system must have boiler control room indicators and alarms for operating out of normal range.

Spent acid added after point of final concentration must have control room flow read out to avoid excess dilution

Impacts of combining spent acid with the black liquor stream to the recovery boiler:

Heating Value: Addition of spent acid will reduce the heating value of the black liquor.

Volatility: Could have H_2S release during pH excursion.

Corrosiveness: Is corrosive, and this must be considered in piping and injection interface design.

Combustion: Non-combustible but could have H_2S

Solids Measurement: Spent acid might lower the black liquor refractometer solids reading by precipitating out lignins if not neutralized. Refractometers do not "see" suspended solids so they will not detect precipitated lignins. Spent acid does not affect off-line testing. Operators and Instrument Technicians must understand the effect of spent acid on the refractive index and off-line testing. The system must not compromise the minimum solids liquor divert recommended by Safe Firing of Black Liquor.

When adding after point of final concentration an off-line solids measurement test must be conducted immediately after introduction or removal of spent acid and at 2-hour intervals any time spent acid is blended into black liquor. After removal of spent acid, a second test must be done within 2 hours. The last test provides data for re-establishing correct on-line solids readings.

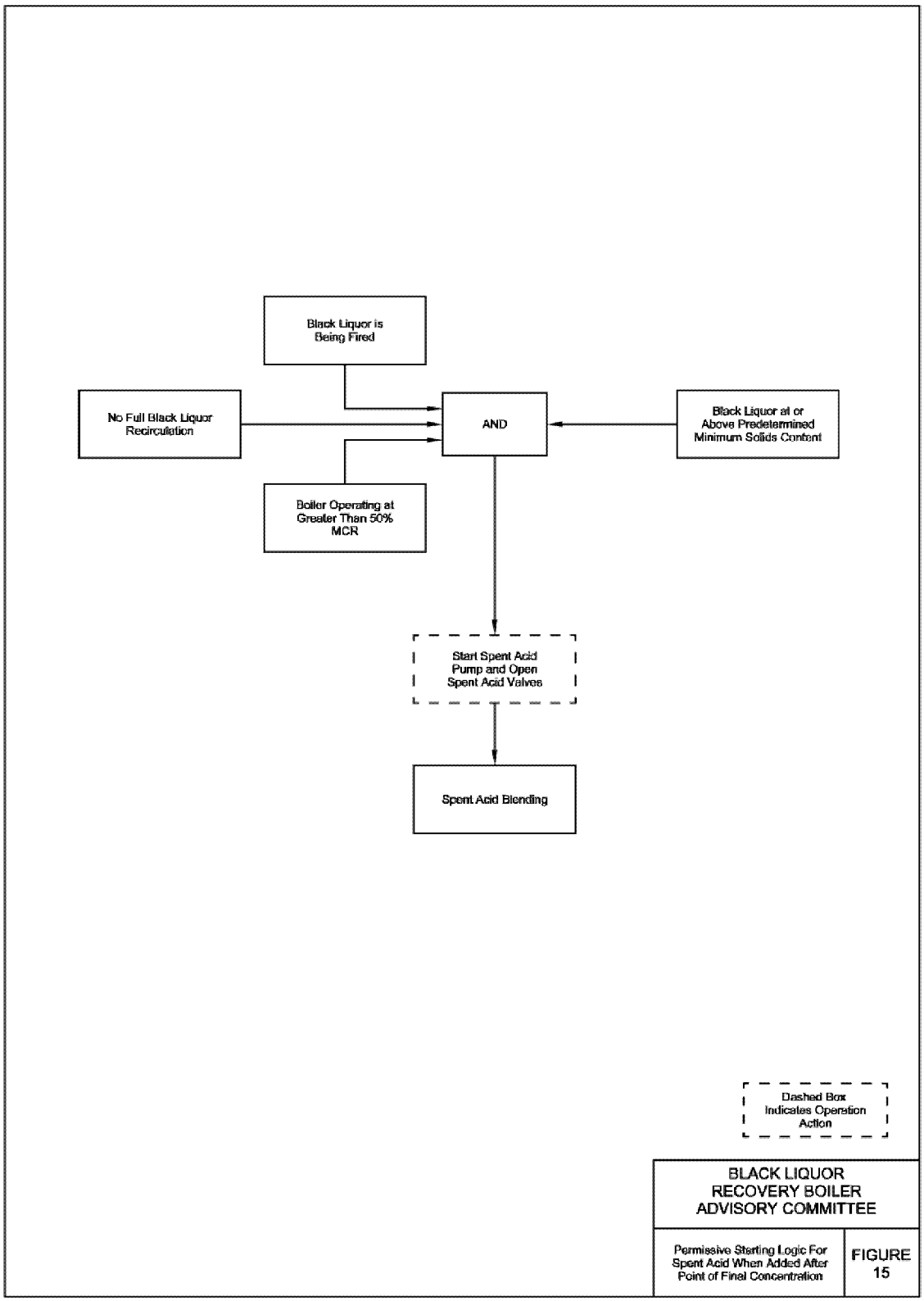

Figure 15 Permissive Starting Logic for Spent Acid when added after Point of Final Concentration.

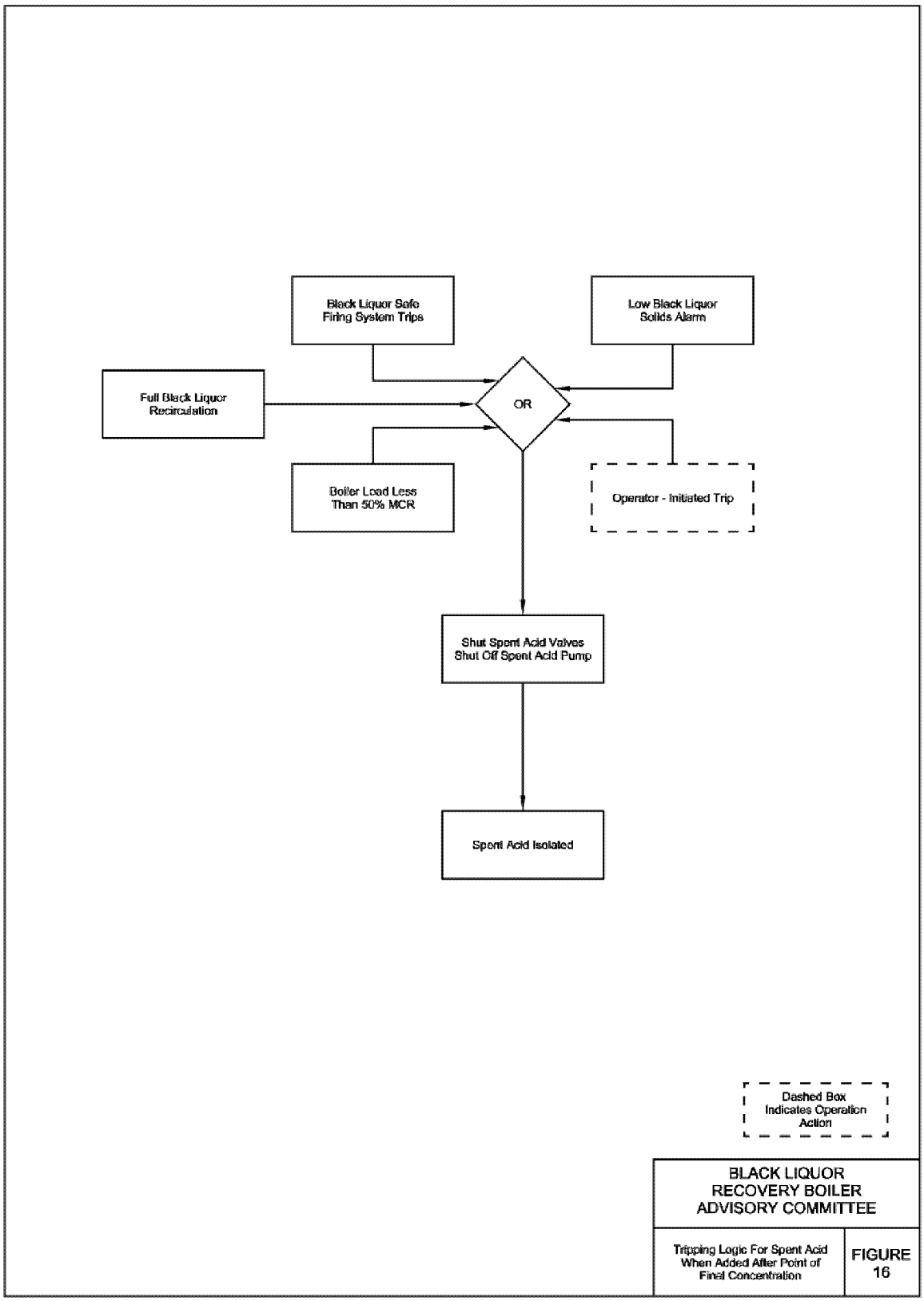

Figure 16 Tripping Logic for Spent Acid when added after Point of Final Concentration.

6.6 Tall Oil

Definition: Tall Oil is a mixture of fatty acids, rosin and neutral materials resulting from the acidulation of soap skimmings from kraft black liquor. Specific gravity is approximately 0.9. Heating value for tall oil is in the range of 16,000 to 18,000 BTU/Lb.

Safeguards for combining tall oil with the black liquor stream to the recovery boiler:

Where: Due to low specific gravity, add tall oil to black liquor after the point of final concentration in black liquor piping downstream of tankage including the salt cake mix tank. To ensure adequate mixing, consider adding the tall oil to the suction of the black liquor fuel pumps. If not added to the black liquor pump suction, the addition should occur far enough upstream in the piping to ensure proper mixing.

Addition point must be upstream of refractometers.

How: Include a "management of change" procedure when you are designing or modifying a system to blend tall oil with black liquor.

Blend with black liquor using in-line mixing.

Ensure consistent refractometer reading by feeding tall oil continuously.

Tall oil must be isolated with a double isolation valve arrangement located near the tall oil injection point in the black liquor line. This location minimizes residual tall oil drainage into black liquor after the valves shut.

The upper limit on tall oil firing should be established by assuming that if the tall oil flow were 100% water, the black liquor solids concentration would not fall below minimum safe firing level.

Interlocks: Boiler must be operated in accordance with the Safe Firing of Black Liquor Guidelines.

Tall oil can only be added to the liquor system when the operation of the recovery boiler is stable and firing liquor at a minimum load of 50% MCR.

When safe firing system trips the black liquor system feed, the tall oil feed is isolated by automatically closing both isolation valves on the tall oil feed line. The tall oil pump can continue to run, allowing tall oil to recirculate when not being blended with black liquor.

Tall oil feed must be stopped whenever black liquor is recirculated rather than fired to prevent build up of tall oil in liquor storage tanks.

Tall oil blending in a liquor firing system that continuously recirculates a portion of the liquor stream to tanks must have continuous agitation in the tanks to avoid separation of tall oil and liquor.

Tall oil feed must be stopped at the low black liquor solids alarm point. Waste stream addition could be the cause of the low solids alarm, so a reasonable first step when solids are low is to stop waste stream addition.

A minimum black liquor solids content for allowing tall oil introduction should be determined and used as a starting permissive for tall oil incineration. This permissive can avoid a low solids alarm caused by a drop in refractometer liquor solids due to tall oil addition.

Starting and tripping logic diagrams for tall oil are included at the end of this tall oil section (see Figures 17 and 18).

Measurements: Tall oil flow rate must be measured and proportioned to black liquor firing rate.

The tall oil delivery system must have control room indication when tall oil is being introduced.

Impacts of combining tall oil with the black liquor stream to the recovery boiler:

Heating Value: Tall oil heating value is in the range of 16,000 to 18,000 Btu/lb. Thus the heat release of the tall oil will be considerably higher than that of black liquor.

Volatility: Not volatile at handling temperatures.

Corrosiveness: Not corrosive.

Combustion: Flash point from 385°F to 420°F as compared to 100°F to 150°F for fuel oil.

Solids Measurement: Addition of tall oil will lower the refractive index, making the refractometers read a lower solids than actual. The decrease would be due to tall oil having a refractive index lower than black liquor. Operators and Instrument Technicians must understand the effect of tall oil on the refractive index. The system must not compromise the minimum solids liquor divert recommended by Safe Firing of Black Liquor.

An off-line solids measurement test must be conducted immediately after introduction or removal of tall oil and at 2-hour intervals any time tall oil is blended into black liquor. After removal of tall oil, a second test must be done within 2 hours. The last test provides data for re-establishing correct on-line solids readings.

The tall oil can coat the refractive lens resulting in inaccurate readings. The prism wash frequency will increase.

Increasing the quality of tall oil mixing will cause fewer problems with the refractometers.

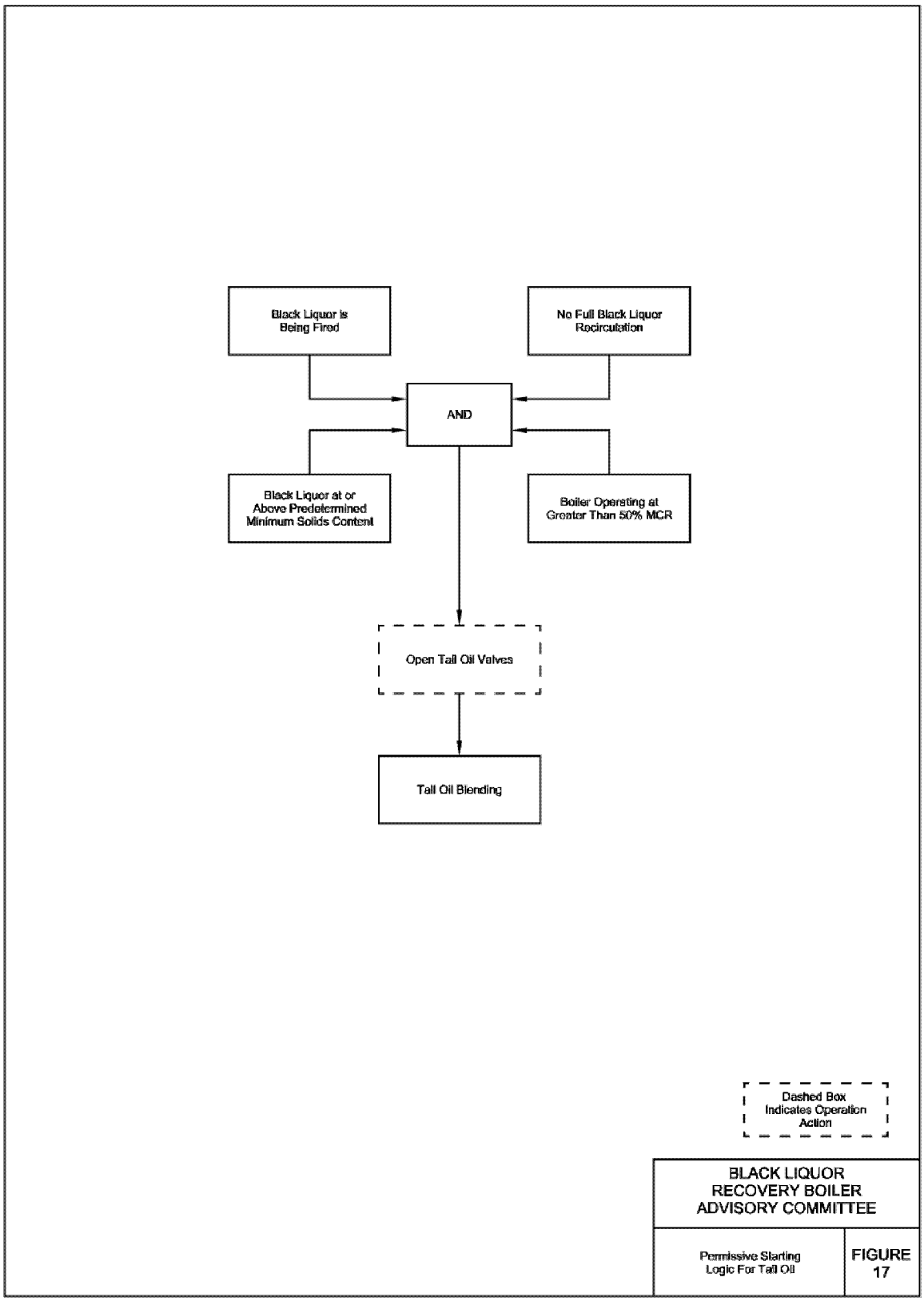

Figure 17 Permissive Starting Logic for Tall Oil.

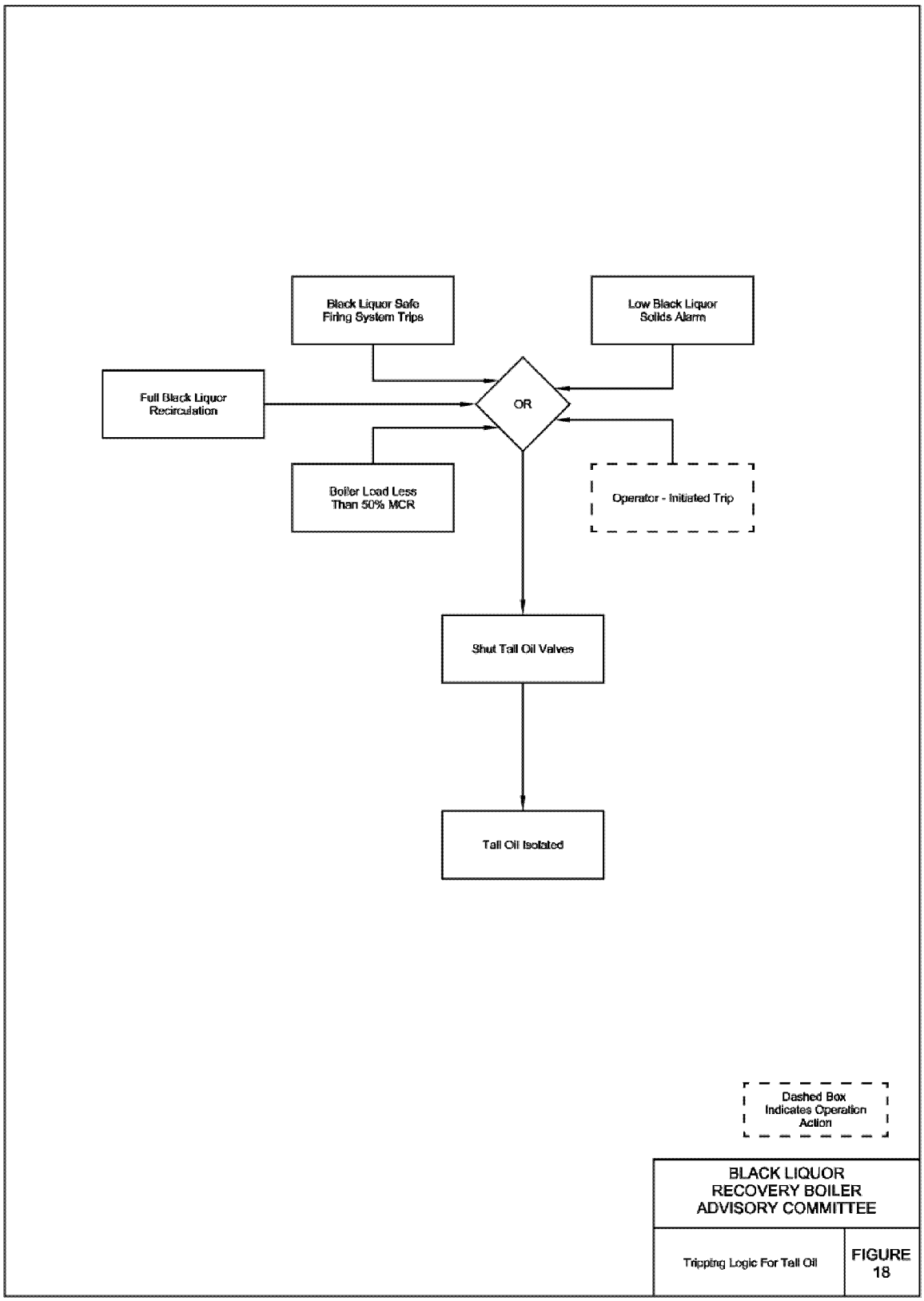

Figure 18 Tripping Logic for Tall Oil.

6.7 Turpentine

Definition: Most spruces, firs and pines are rich in terpenes that can be recovered from flashing and evaporation of black liquor. Typically contaminated to varying degrees with sulfides, crude sulfate turpentine has a market value that is usually high enough that it is preferably sold rather than burned. In cases where the sulfide levels are too high or the terpene composition is of poor quality, incineration may be the only available disposal option.

In addition to direct recovery of turpentine from condensed vapor, foul condensate stripping systems can generate sulfide-rich foul turpentine, or "Red Oil" that is not marketable. Most stripping systems are designed and operated to keep the turpentine vaporized in the methanol-rich Stripper Off-Gas. Some existing older designs still generate a decanted oil layer that requires special handling and disposal.

Generation rates in Kraft batch mills where turpentine quality is generally good are about 0.5-1.5 gallons/bdt softwood chips. Continuous Kraft cooking generates between 0.3-1.0 gallons of turpentine/bdt chips.

Mills that produce poor quality turpentine also typically generate less overall, usually between 0.1-0.15 gallons/bdt chips. On a 75% black liquor solids basis, this amounts to about 0.05% by volume. Addition of Stripper-generated "Red Oil" may increase this rate to 0.1%. For example, a mill that burns 400 gpm of heavy liquor will have a turpentine flow of about 0.4 gpm, or 1.5 L/min. Some mills are firing black liquor blended with up to 1% turpentine by volume.

Safeguards for combining turpentine with the black liquor stream to the recovery boiler:

Where: Add turpentine to black liquor after the point of final concentration in black liquor piping downstream of tankage including the salt cake mix tank to minimize the possibility of explosive gases in the vapor space in tanks.

Addition should occur far enough upstream in the piping to ensure adequate mixing.

Because of the high recirculation rate in the heating loop, it may be preferable to inject turpentine downstream of the black liquor indirect heater system.

Turpentine injection must be downstream of a direct heater to prevent flashing of turpentine when the loss of steam desuperheating results in the steam temperature exceeding 350F.

The addition point <u>must</u> be upstream of refractometers.

How: Include a "management of change" procedure when you are designing or modifying a system to blend turpentine with black liquor.

Turpentine flow must be metered by continuous injection to maintain a safe black liquor to turpentine ratio and to provide consistent refractometer readings. A suggested upper limit is 0.5% by volume of turpentine solution in black liquor.

Blend with black liquor using in-line mixing via direct injection.

As with methanol solution, crude sulfate turpentine and "Red Oil" are high in odorous sulfide and nitrogen compounds that can permeate furnace wall deposits and generate operating floor odors in the event of furnace pressure upsets.

Turpentine must be isolated with a double isolation valve arrangement located near the turpentine injection point in the black liquor line. This location minimizes residual turpentine drainage into black liquor after the valves shut.

Interlocks: Boiler must be operated in accordance with the Safe Firing of Black Liquor Guidelines.

Turpentine can only be added to the liquor system when the operation of the recovery boiler is stable and firing liquor at a minimum load of 50% MCR.

When safe firing system trips the black liquor system feed, the turpentine feed is isolated by stopping the pump and automatically closing the downstream isolation valve on the turpentine feed line. Both stopping the pump and closing the valve will ensure positive isolation of turpentine.

Turpentine feed must be stopped whenever black liquor is re-circulated rather than fired to prevent build up of turpentine and resulting vapors in black liquor piping and in liquor storage tanks. An exception to this requirement is partial recirculation to a tank that is vented to the CNCG or a pressurized storage tank that flashes back to the evaporators.

Turpentine feed must be stopped at the low black liquor solids alarm point. Waste stream addition could be the cause of the low solids alarm, so a reasonable first step when solids are low is to stop waste stream addition.

A minimum black liquor solids content for allowing turpentine introduction should be determined and used as a starting permissive for turpentine incineration. This permissive can avoid a low solids alarm caused by a drop in refractometer liquor solids due to turpentine addition.

All turpentine injection should be stopped well in advance of any planned removal of a liquor gun or nozzle to allow sufficient time to purge turpentine-bearing liquor from the system.

Starting and tripping logic diagrams for turpentine are included with this turpentine section.

Measurements: The turpentine delivery system must have control room indication when turpentine is being introduced.

Flow rate shall be measured.

Consider having high and low flow alarms.

Impacts of combining turpentine with the black liquor stream to the recovery boiler:

- **Heating Value:** Higher heating value for 100% turpentine is about 19,000 Btu/lb.
- **Volatility:** Turpentine's boiling point is about 300°F.
- **Corrosiveness:** Corrosive due to sulfide content; use stainless steel, preferably welded fittings.
- **Combustion:** Flash point for pure turpentine is about 95°F (closed cup) as compared to 100°F to 150°F for fuel oil; however, sulfide content can lower the measured values to <50°F. Auto-ignition temperature of turpentine is 400°F.
- **Solids Measurement:** When firing turpentine with black liquor, the black liquor refractive index will slightly decrease, causing an apparent lower solids measurement of up to 0.6% for a 1% by volume addition of turpentine. The decrease would be due to turpentine having a refractive index lower than black liquor. Off-line testing method will not be affected by turpentine (but there may be an odor during off-line testing.), but results may be slightly lower percent solids due to vaporization of turpentine during the cook techniques. The percentage lower would be dependent on percent volume of turpentine. Operators and Instrument Technicians must understand the effect of turpentine on the refractive index and off-line testing. The system must not compromise the minimum solids liquor divert system recommended by Safe Firing of Black Liquor.

- An off-line solids measurement test must be conducted immediately after introduction or removal of turpentine and at 2-hour intervals any time turpentine is blended into black liquor. Off-line testing must recognize the odor potential of turpentine.

- Turpentine addition is not expected to accelerate build-up on the refractive lens.

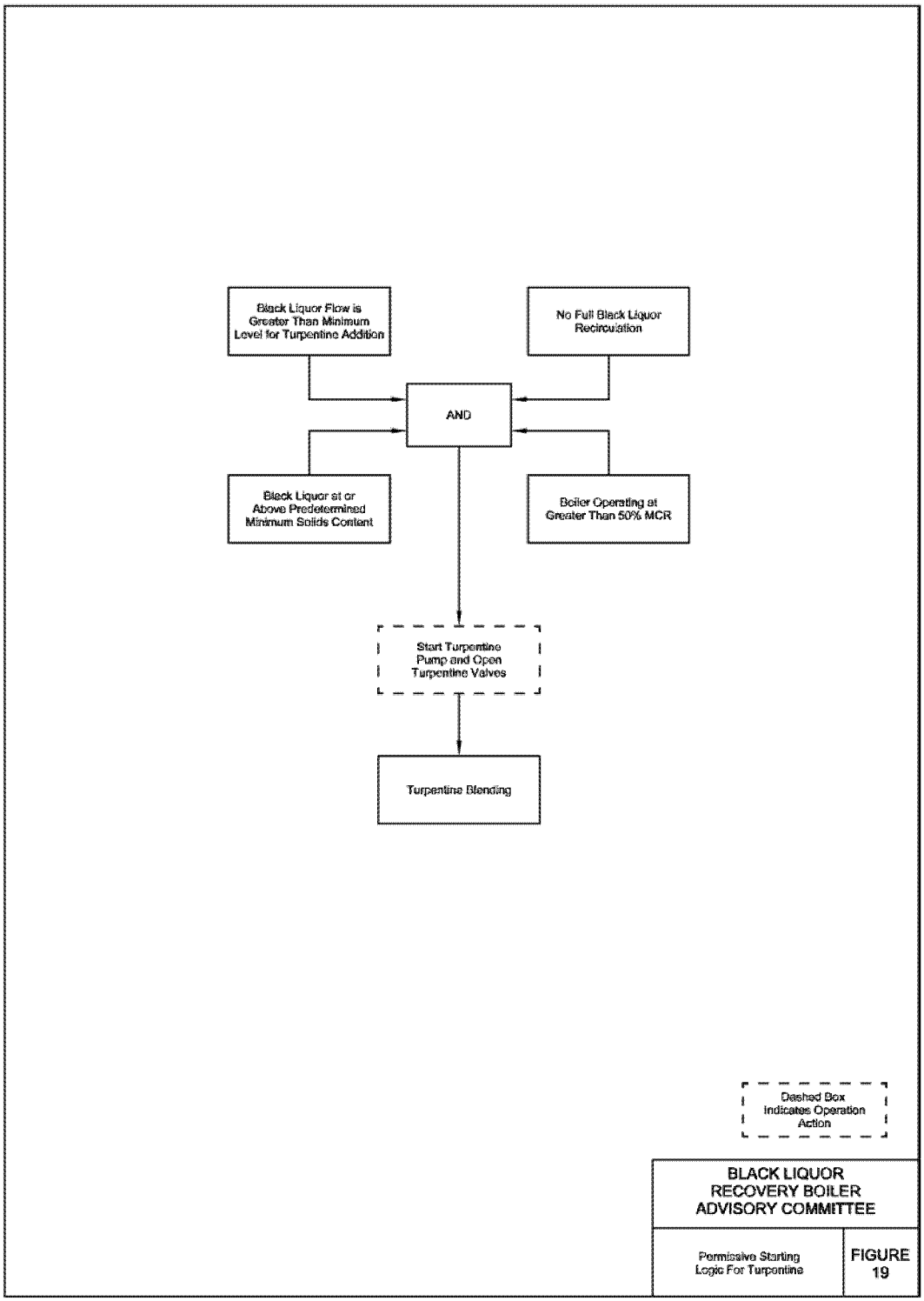

Figure 19 Permissive Starting Logic for Turpentine.

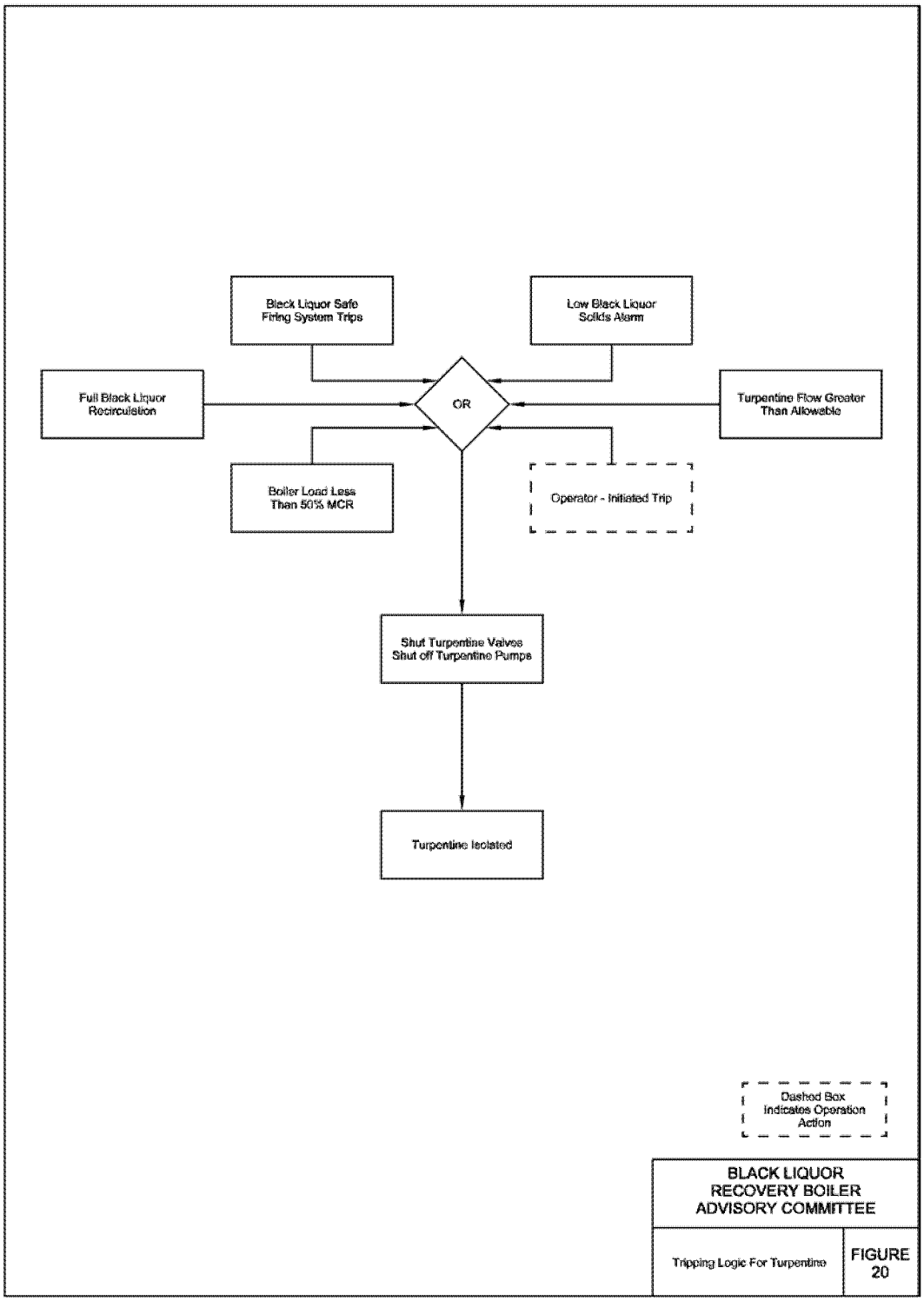

Figure 20 Tripping Logic for Turpentine.

CHAPTER 7 GUIDELINES FOR THERMAL OXIDATION OF LIQUID WASTE STREAMS IN DEDICATED BURNERS

7.1 Introduction

Chapter 7 describes the use of dedicated burners as the control devices for thermal oxidation of liquid waste steams in recovery boilers. While many liquid waste streams are generated in the chemical recovery and wood pulping processes, this guideline is applicable only to combustible liquid waste streams. The most common liquid waste streams that meet this requirement are methanol, turpentine and tall oil. These liquid streams may be fired separately, or in a blended combination. A dedicated burner may not be the best location to oxidize these streams, and there may be other waste streams that have similar characteristics to these streams that are not specifically mentioned in this document. The purpose of this document is to describe recommended guidelines for thermal oxidation of any liquid waste stream in dedicated burners, with additional information provided for the waste streams considered to be the most common candidates for such incineration.

Attempting to oxidize a non-combustible liquid waste stream in a dedicated burner may be an ineffective oxidation method at best, and a possible hazard to safe boiler operation. Non-combustible liquid waste streams should be disposed of by means other than a dedicated burner in a recovery boiler. These streams include, but are not limited to spent acid and secondary sludge.

The thermal oxidation of liquid waste streams in dedicated burners in recovery boilers is very similar to the firing of fuel oil in auxiliary burners in recovery boilers. The basic physical characteristics of the equipment and materials involved are very similar. The recommendations described in the "Recommended Good Practice for Safe Firing of Auxiliary Fuels in Black Liquor Recovery Boilers," with some specific additional recommendations, apply directly to the thermal oxidation of liquid waste streams in dedicated burners in recovery boilers. These specific additional recommendations are described in this chapter.

These recommendations should be followed in addition to those given for fuel oil fired burners in the "Recommended Good Practice for Safe Firing of Auxiliary Fuels in Black Liquor Recovery Boilers." In the case of the dedicated liquid waste stream burner, the liquid waste stream is treated as an "Auxiliary Fuel" for the burner. This is a direct contradiction of the definition of an Auxiliary Fuel given in the "…Safe Firing of Auxiliary Fuel…" guideline, but it is necessary for the purposes of this guideline and it does not violate the spirit of the recommendations for auxiliary fuels. Consideration of the heating pattern generated by the liquid waste stream burner will be of limited importance in most cases. As a matter of clarity, the auxiliary fuel guidelines specific to gas fired main burners will not apply to liquid waste stream burners.

7.2 Safety

7.2.1 System Safety

For the purpose of this guideline, liquid waste streams that are permissible to fire in a dedicated burner are considered fuels. For specific guidelines concerning the basic acceptable characteristics of liquid waste streams that may be fired in a dedicated burner, please refer to section 7.4 of this document.

During the thermal oxidation of liquid waste streams in dedicated burners, the safety hazards for both personnel and equipment have to be considered. The equipment for thermal oxidation as well as handling and transporting the liquid waste stream has to be designed and controlled such that:

- The liquid waste stream cannot escape into the recovery boiler building.
- Fire and explosion in equipment and piping systems is prevented.
- Positive ignition of the liquid waste stream entering the furnace is provided.
- The boiler should be operating at a load of 50% or greater.
- The waste stream does not contain excessive water as determined by density or other appropriate measurement.

At a minimum, the safety requirements for the thermal oxidation of liquid waste streams in a dedicated burner must meet the guidelines presented in the following BLRBAC publications:

- Recommended Good Practice for the Safe Firing of Auxiliary Fuels in Black Liquor Recovery Boilers
- Recommended Good Practice for the Safe Firing of Black Liquor in Black Liquor Recovery Boilers
- Recommended Rules for Personnel Safety for Black Liquor Recovery Boilers
- Instrumentation Checklist and Classification Guide for Instruments and Controls Used in Operation of Black Liquor Recovery Boiler

7.2.2 Personnel Safety

The liquid waste streams must be handled with great care. Each waste stream has unique hazards that must be considered. Some general characteristics of various liquid waste streams, and their associated hazards are discussed in the next section. For more specific risks associated with hazardous compounds present in liquid waste streams, see published health and safety guidelines concerning these compounds. The nature of each liquid waste stream must be clearly understood prior to the design of a dedicated waste stream burner and handling system.

Areas containing liquid waste stream piping and equipment should be monitored in accordance with applicable safety codes.

Routine inspection and repair of the liquid waste stream transport system should be performed at sufficient frequency to prevent leaks in the system and/or malfunction or failure of control devices.

Some tasks associated with the normal operation of a dedicated liquid waste stream burner may potentially expose operators to noxious fumes or other hazards. These hazards must be clearly understood and the proper personal protective equipment (PPE) must be identified and used as needed. Proper system purge, maintenance and lock out procedures must be developed and strictly adhered to.

7.3 Descriptions of Liquid Waste Streams Expected to be Fired in Dedicated Burners

7.3.1 Methanol

Liquid methanol is typically condensed from stripper off gas (SOG). SOG consists of approximately 50 percent methanol vapor by weight. SOG can be converted to a liquid of high methanol concentration and heating value through the process of methanol rectification. This liquid typically has a methanol content of 50 to 80 percent by weight, but can range from 30 to 90 percent. Methanol from SOG usually contains TRS, turpenes, and other contaminants that make it noxious. Care should be taken to design dedicated methanol burners and transport systems to limit personnel exposure to methanol vapor and liquid. Proper PPE should be identified for and used by operators of methanol burners. The exposure limits and hazards of other chemicals that might be present in methanol must also be identified and appropriate protective measures must be taken.

Physical & Chemical Properties
Physical State: Liquid
Appearance: clear, colorless
Odor: alcohol-like – weak odor
pH: N/A
Vapor Pressure: 127 mm Hg @ 25 deg C
Vapor Density: 1.11 (Air = 1)
Evaporation Rate: 2 (Butyl acetate = 1)
Viscosity: 0.55 cP @ 20 deg C
Boiling Point: 64.7 deg C @ 760.00 mm Hg
Freezing/Melting Point: -98 deg C
Auto-ignition Temperature: 464 deg C (867.20 deg F)
Flash Point: 11 deg C (51.80 deg F) or less depending on Sulfur content
NFPA Rating: (estimated) Health: 1; Flammability: 3; Reactivity: 0
Explosion Limits, Lower: 6.0 vol %;Upper: 36.00 vol %
Solubility in water: miscible
Specific Gravity/Density: 0.7910g/cm3

The above properties are for pure methanol and may vary significantly depending on the concentration of contaminants, such as sulfur compounds, in the methanol stream.

7.3.2 Turpentine and Red Oil

Sulfate turpentine is a by-product of the pulping of softwood. Sulfate turpentine is collected from digester relief gases, and may contain additional hazardous chemicals such as dimethyl sulfide, dimethyl disulfide and methyl mercaptan. Red oil, such as that decanted from foul condensate stripping systems is considered the same as turpentine in this Chapter. Turpentine is explosive and has an undefined upper explosion limit. Turpentine is noxious. Care should be taken to design dedicated turpentine burners and transport systems to limit personnel exposure to turpentine vapor and liquid. Proper PPE should be identified for and used by operators of turpentine burners.

Physical & Chemical Properties
Physical State: Liquid
Appearance: clear to dark brown
Odor: foul Kraft pulp mill odor
pH: N/A
Vapor Pressure: 5 mm Hg @ 25 deg C
Vapor Density: 4.8 (Air = 1)
Evaporation Rate: 0.4 (Butyl acetate = 1)
Viscosity: N/A
Boiling Point: 119 to 173 deg C @ 760.00 mm Hg
Freezing/Melting Point: -50 to -60 deg C
Auto-ignition Temperature: 253 deg C (488 deg F)
Flash Point: 23 to 35 deg C (73 to 95 deg F) or less depending on sulfur content
NFPA Rating: (estimated) Health: 2; Flammability: 3; Reactivity: 0
Explosion Limits, Lower: 0.8 vol %; Upper: Unknown
Solubility in water: 0.023% @ 25 deg C
Specific Gravity/Density: 0.87g/cm3

The above properties are for pure turpentine and may vary significantly depending on the concentration of contaminants, such as sulfur compounds, in the turpentine stream.

7.3.3 Crude Tall Oil

Crude tall oil is a mixture of fatty acids, rosin and neutral materials resulting from the acidulation of soap skimmings from Kraft black liquor. The crude tall oil is pumped to the recovery boiler from the crude tall oil storage tank. Care should be taken to design dedicated crude tall oil burners and transport systems to limit personnel exposure to crude tall oil liquid or vapor. Proper PPE should be identified for and used by operators of crude tall oil burners.

Physical & Chemical Properties
Physical State: Liquid
Appearance: amber to dark brown
Odor: acrid
pH: 11 to 12
Vapor Pressure: negligible @ 25 deg C
Vapor Density: 0 (Air = 1)
Evaporation Rate: under 1 (Butyl acetate = 1)
Viscosity: N/A
Boiling Point: 260 deg C @ 760.00 mm Hg
Freezing/Melting Point: N/A
Auto-ignition Temperature: N/A
Flash Point: 191 to 193 deg C (375 to 380 deg F)
NFPA Rating: (estimated) Health: ?; Flammability: ?; Reactivity: ?
Explosion Limits, Lower: N/A; Upper: N/A
Solubility in water: negligible
Specific Gravity/Density: 0.95 to 1.00g/cm3

The above properties are for pure tall oil and may vary significantly depending on the concentration of contaminants, such as sulfur compounds, in the tall oil stream.

7.4 Recommended Waste Stream Characteristics

7.4.1 Basic Acceptable Characteristics for Combustion in a Dedicated Burner

The water content of any liquid waste stream should be minimized. If the liquid waste stream contains water, it should be fully miscible. There should be sufficient heat content in the waste stream to fully evaporate any water it contains. If a liquid waste stream is to contain water, some positive means of monitoring the water content must be used and an acceptable upper limit of water concentration must be established. If this upper limit is exceeded, the liquid waste stream must be diverted from the burner.

The liquid waste stream viscosity should be low enough to allow effective flow and atomization. If the viscosity of the liquid waste stream is too high at ambient temperature, it should be heated until an acceptable viscosity is achieved. Viscosity should also be relatively constant. Significant variation in viscosity can cause poor atomization and flame instability. The expected absolute viscosity limits and variability are to be provided to the burner designer.

The liquid waste stream should be as homogeneous as possible. Homogeneity is important to flame stability. Should the waste stream be a blend of different streams, the multiple streams should be fully miscible to avoid slug flow of different streams.

The liquid waste stream must have a net positive heating value. Wide variation in waste stream heating value during burner operation can cause an unsafe air to fuel ratio at the burner and flame instability. Heating value variation should be maintained within a sufficiently narrow band to avoid these problems. The burner designer must be made aware of the absolute limits of the waste stream heating value and of the potential for variation of heating value.

7.4.2 Characteristics of Class A Waste Streams

Class A waste streams possess characteristics that will allow them to be safely fired in a dedicated burner without a separate continuous positive ignition source. The flame produced by these streams can be effectively scanned and discriminated from other combustion within the furnace. In addition to the basic acceptable characteristics, the key characteristics of these streams are homogeneity, sufficient volatility for positive ignition, and limited variation in heating value and other physical characteristics. The specific limits of each of these characteristics must be defined by the burner designer with consideration of the overall operating environment of the waste stream burner including, but not limited to, combustion air conditions and supply, atomizing medium, flame scanner performance and combustion conditions within the furnace. Class A waste streams may be used to fire support burners for other liquid or gaseous waste streams.

The final decision on classification of waste streams as Class A rests with the burner designer.

7.4.3 Characteristics of Class B Waste Streams

Class B waste streams posses characteristics that will allow them to be safely fired in a dedicated burner with a separate continuous positive ignition source, but are not of sufficient quality to be considered Class A waste streams. This separate ignition source will be of sufficient heat input to provide positive stable ignition of the liquid waste stream based on the requirements of the burner designer. The final decision on classification of waste streams as Class B rests with the burner designer.

7.4.4 Characteristics of Class C Waste Streams

Any liquid waste stream not classified as Class A or B is classified Class C. These streams do not possess the basic acceptable characteristics. These streams must not be fired in dedicated burners. Two examples of these streams are spent acid and secondary sludge.

7.5 Dedicated Burners for Thermal Oxidation

7.5.1 All Dedicated Burners

The waste stream burner(s) should be mechanically suited for installation and operation in a Kraft recovery boiler. Some specific issues might include smelt flow across the burner tip and high radiant heat from the furnace. The ultimate responsibility for the final design of the waste stream burner, including consideration of all the following parameters lies with the burner supplier.

The waste stream burner(s) should have a dedicated air system. The combustion air can be supplied from a separate fan or from a recovery boiler FD fan. Proof of adequate combustion air flow is required as proven by a flow switch or other suitable means.

Liquid waste streams may be conveyed to the burner through independent lines and injected into the flame zone separately. It is acceptable to have multiple separate liquid waste stream atomizers within a single burner. It is also permissible to fire the liquid streams in a blended condition. Should the waste stream be a blend of different streams, the multiple streams should be fully miscible to be classified as a Class A waste stream. Blended waste streams that are not fully miscible must be classified as Class B. The combined maximum total heat input for the liquid waste stream burner must not exceed the maximum heat input for a single burner recommended by the boiler designer. If the burner designer is also an OEM for Kraft recovery boilers, they may set the maximum waste stream burner heat input based on their own design criteria.

The atomizer design and atomizing medium should be selected with consideration of the flash point of the liquid waste stream to prevent flashing of the fluid in the atomizer.

Atomizer design should also consider the viscosity of the waste stream. Heating of the waste stream to achieve sufficiently low viscosity may be acceptable, but may present problems with blended streams including streams of both high and low flash points.

The burner should be placed in the high heat zone of the furnace at or below the tertiary air level, at an elevation low enough in the furnace to allow complete burn out of the waste stream before it can exit the furnace. It should be placed in such a manner that disturbances in the main flame and/or igniter flame are avoided so as to not create difficulty with flame detection for either the waste streams or the support flame (if required), or the lighter.

7.5.2 Burners Firing Class A Streams

If the waste stream to be fired is a Class A stream, the dedicated waste stream burner is not required to have a separate continuous positive ignition source. The flame safety system for this type of burner will rely on positive detection of the waste stream flame. This liquid waste burner must be equipped with a flame detection device able to detect the waste stream flame, and able to discriminate that flame against the furnace background. The waste stream flame must have sufficient stability and be located such that it can be effectively detected by the flame scanner.

7.5.3 Burners Firing Class B Streams

Liquid waste burners firing Class B streams must be equipped with a continuous ignition source with sufficient heat input to ensure stable ignition and combustion of the waste stream. The lighter must be equipped with its own independent flame detection device, and it must be run at all times the liquid waste burner is in service. This lighter should operate during the shut down of the waste stream burner to combust the waste stream during this typically unstable period, and while purging liquid waste from the burner.

7.6 Protective Starting and Tripping Logic

Unless specifically stated otherwise in this guideline, all general design criteria for dedicated burners for liquid waste streams must meet "Recommended Good Practice for the Safe Firing of Auxiliary Fuels in Black Liquor Recovery Boilers". As stated in section 7.1, the design and operation of dedicated burners for the thermal oxidation of liquid waste streams is very similar to that of auxiliary fuel burners. This similarity also applies to protective starting and tripping logic. In an attempt to avoid future inaccuracies in the coordination between this guideline and the "Recommended Good Practice for Safe Firing of Auxiliary Fuels in Black Liquor Recovery Boilers," this document refers to that guideline for most design and logic requirements.

There will be additional logic requirements for dedicated burners for the thermal oxidation of liquid waste streams, but these requirements will be dictated by the specific

waste stream and burner design. The burner designer will be responsible for identifying those logic requirements that are applicable and not described in the "Recommended Good Practice for Safe Firing of Auxiliary Fuels in Black Liquor Recovery Boilers".

Some examples of additional requirements that may be required are:

- The waste stream does not contain excessive water as determined by density or other appropriate measurement.
- The waste stream meets all limits for physical characteristics set by the burner designer, such as minimum and maximum temperature and pressure limits, etc.
- The burner atomizing medium meets all limits for physical characteristics and characteristics in relation to the liquid waste stream set by the burner designer.

CHAPTER 8 GUIDELINES FOR THERMAL OXIDATION OF CHIP BIN NCG

8.1 Introduction

Environmental regulations may require that the vents from most continuous digester chip bins that are pre-steamed be collected and destroyed. This chapter discusses the range of risks that chip bin noncondensible gas (CBNCG) presents, the choices for transporting these gases to a recovery boiler, and how to use a recovery boiler for safely destroying CBNCG.

8.1.1 Safety

During the thermal oxidation of CBNCG, the safety for both personnel and equipment must be considered.

Chip Bin NCG is ordinarily "malodorous-air" that has the potential of becoming flammable under upset operating conditions. Each CBNCG system requires an individual evaluation because each system has a unique combination of risk factors. CBNCG is not a fuel. Systems and equipment for thermal oxidation of CBNCG, as well as the systems and equipment for collection and treatment, should be designed and controlled such that:

- The escape of CBNCG into the recovery building area is prevented insofar as design makes it possible.
- Condensate cannot carry into the recovery boiler.
- Special consideration should be placed on the design of CBNCG recognizing that conditions can occur where the concentration can become flammable.
- Surrogate parameters for a CBNCG combustible content above the LEL are used as interlocks to divert CBNCG when it is hazardous. Use of an LEL meter is encouraged. NFPA 69, chapter 6, permits operating at up to 60% LEL when interlocks are in place.
- In no case shall the safety requirements be less restrictive than those presented in the following BLRBAC publications:
    - Recommended Good Practice for the Safe Firing of Auxiliary Fuel in Black Liquor Recovery Boilers
    - Recommended Good Practice for the Safe Firing of Black Liquor in Black Liquor Recovery Boilers
    - Instrumentation Checklist and Classification Guide for Instruments and Control Systems Used in Operation of Black Liquor Recovery Boilers
    - Recommended Rules for Personnel Safety Black Liquor Recovery Boilers

8.1.2 Flammability of CBNCG

Table 10 lists factors that can affect the flammability of CBNCG. An assessment of these at a given site will help the system designer select the most appropriate means for safe handling of these gases.

Table 10 Risk Factors Affecting the Flammability of Chip Bin NCG

Risk Factor	Result
Process Risk Factors	
• Resinous softwoods (Not hemlock nor hardwoods)	• Contributes turpentine
• Eucalyptus	• Contributes volatile oils
• Flash steam pre-steaming	• Contributes TRS, methanol, turpentine, volatile oils
• Early extraction in cont. digester	• Higher turpentine content in flash steam
• Chip pile storage time	• Short term storage decreases volatile losses
• Season	• Low temperatures decreases volatile losses
• Low residual alkali	• Higher TRS in flash steam
Operational Risk Factors	
• Chip level	• Breakthrough of flash steam volatiles
• High top vent temperature	• Volatiles in NCG increase with temperature
• Lower than normal vent temperature	• Returning to normal temp will re-vaporize volatile compounds
• High NCG temperature out of condenser	• Reduces turpentine removal
• Chip bin residence time	• Increases volatile accumulation
• Excessive sweep air	• Reduces condensing efficiency
• Digester start up	• Unstable chip bin operation, high combustible content

The majority of risk factors involve turpentine, which is a product of resinous softwood, and organic sulfides that get returned to the chip bin if digester flash steam is used for pre-steaming. TRS and volatile oils behave similarly. A mill that uses fresh steam for pre-steaming hardwood chips will likely generate CBNCG having lower flammable gas concentrations than a mill that pre-steams softwood chips with extraction liquor flash steam. The following summarizes the decreasing risk of generating flammable NCG concentrations:

Softwood Chips >> Softwood Chips = Hardwood Chips > Hardwood Chips
Flash Steam Fresh Steam Flash Steam Fresh Steam

8.2 Collection and Transfer of CBNCG

8.2.1 CBBNCG Conditioning System

The intent of the CBNCG conditioning system is to reduce the amount of water vapor in the gas, limit the maximum concentration of turpentine in the NCG from softwood processing, and address conditions that can generate flammable gas compositions for any fiber source.

While Chip Bin Vent Condenser temperature control is primarily aimed at limiting the saturated turpentine concentration of the exit vapor, temperature will have less of an impact on TRS content. Operating the Chip Bin at temperatures > 180 ^{o}F with flash steam increases the risk of having flammable concentrations of CBNCG due to TRS, even after cooling. Interlock permissives should include limits on Chip Bin Condenser NCG exit temperature. A maximum cooled gas temperature of 90 ^{o}F is suggested for softwood cooking; however, the maximum temperature setting for hardwood could be set higher 120 ^{o}F would not be unreasonable. If dilution air is added to lower combustible gas concentrations, it should be introduced after the Condenser to reduce the impact on condensing efficiency.

Since the Chip Bin vent will often entrain chips, pins, and fines, the Vent Condenser should be protected from plugging. Systems will often include a Separator and an intermittent tube-side shower.

Pre-steaming Chip Bins should have process interlocks to vent the Chip Bin to the atmosphere under prolonged low Chip Bin level conditions or excessive vent Condenser temperatures. Flash steam should be shut off [The flash steam valve should be ramped down at a rate that does not create a control problem for the flash steam condensers.] as a pre-emptive action before excessive emissions are released into the collection system.

Pre-steaming Chip Bins that operate at cold top temperatures can accumulate high concentrations of TRS and condensed volatiles that can re-vaporize under falling chip levels that result in steam breakthrough. Chip Bins that normally operate hot (top temperature of > 150 ^{o}F) may experience accumulation of TRS and condensed volatiles upon loss in steam flow. These combustibles can be rapidly expelled upon resumption of steaming. To avoid this potential excursion above the LEL, a low bin vent temperature interlock should be included that vents NCG for a minimum time period once conditions return to normal with rising temperature.

Appropriate pre-emptive interlocks recognizing this behavior should be applied to any operating strategy. Figure 19 gives an example of a CBNCG vent condensing system.

8.2.2 Recovery Boiler Introduction System

CBNCG can be introduced for thermal oxidation into the recovery boiler furnace in several ways:

- Through one or more injection nozzles, typically located within a combustion air (tertiary) port entry.
- As part of a dedicated burner for CNCG and SOG
- Combined with DNCG prior to furnace entry

The selected method of introduction of the CBNCG into the furnace needs to consider the gas concentration at the point of injection, the volume of CBNCG and the applicable risk factors. The designer selecting a system to introduce CBNCG into a combustion air duct should recognize the potential for release of odorous and potentially flammable gas into the boiler area due to ductwork leaks, port rodding leakage, sight glass breakage or other leakage sites. A system design that uses direct injection into the furnace through dedicated nozzles or as a stream to a dedicated waste gas burner significantly reduces the possibility of odorous gas release and is the preferred method of disposal. Furthermore, a dedicated system that uses a steam ejector provides safety when the CBNCG combustibles are above the LEL because it does not have the potential ignition sources of a centrifugal fan and steam addition provides dilution of both combustible gas and oxygen concentrations.

Dilution air added to CBNCG will not positively ensure that the resulting stream is always below the LEL. Some risk factors involve re-vaporizing combustibles; and the rate of re-vaporization cannot be accurately predicted, so the resulting concentration, even after dilution, cannot be predicted.

Data from mills indicate that the % LEL of their DNCG systems without the Chip Bin vent is typically 5% - 10%. When Chip Bin gases are included, this % LEL can go much higher and exceed 100%. In that the Chip Bin, when upset, represents the single most likely source of NCG that can jeopardize the safety of a conventional DNCG system, more mills are electing to handle this vent gas separately.

Before selecting CBNCG transport and introduction methods, a “management of change” procedure should be performed. If the” management of change” procedure and evaluation of risk factors allow combining CBNCG with DNCG, then Chapter 4 should be used for design of a recovery boiler introduction system. The remainder of this chapter discusses introduction of CBNCG into the recovery furnace in a dedicated system.

Depending on method of collection, CBNCG replaces a small part of the volume of combustion air. If conveyed by a Steam Ejector, NCG flow excluding ejector steam is typically less than 2000 acfm. If conveyed by a fan, where dilution air is added, total flow will typically be in the 4000 acfm range. These flows may have an effect on the combustion air requirements and should be considered in the system design.

Where direct injection through a nozzle is used, entry velocities should be above the flame propagation velocity to minimize the potential for flameback. A reasonable design velocity is 50 fps. The delivery system should be designed to develop the necessary

pressure required at the furnace nozzles, in which case CBNCG pressure should be monitored and alarmed.

When NCG is diverted, providing a secondary source of air or steam will help prevent injection port damage from high heat exposure.

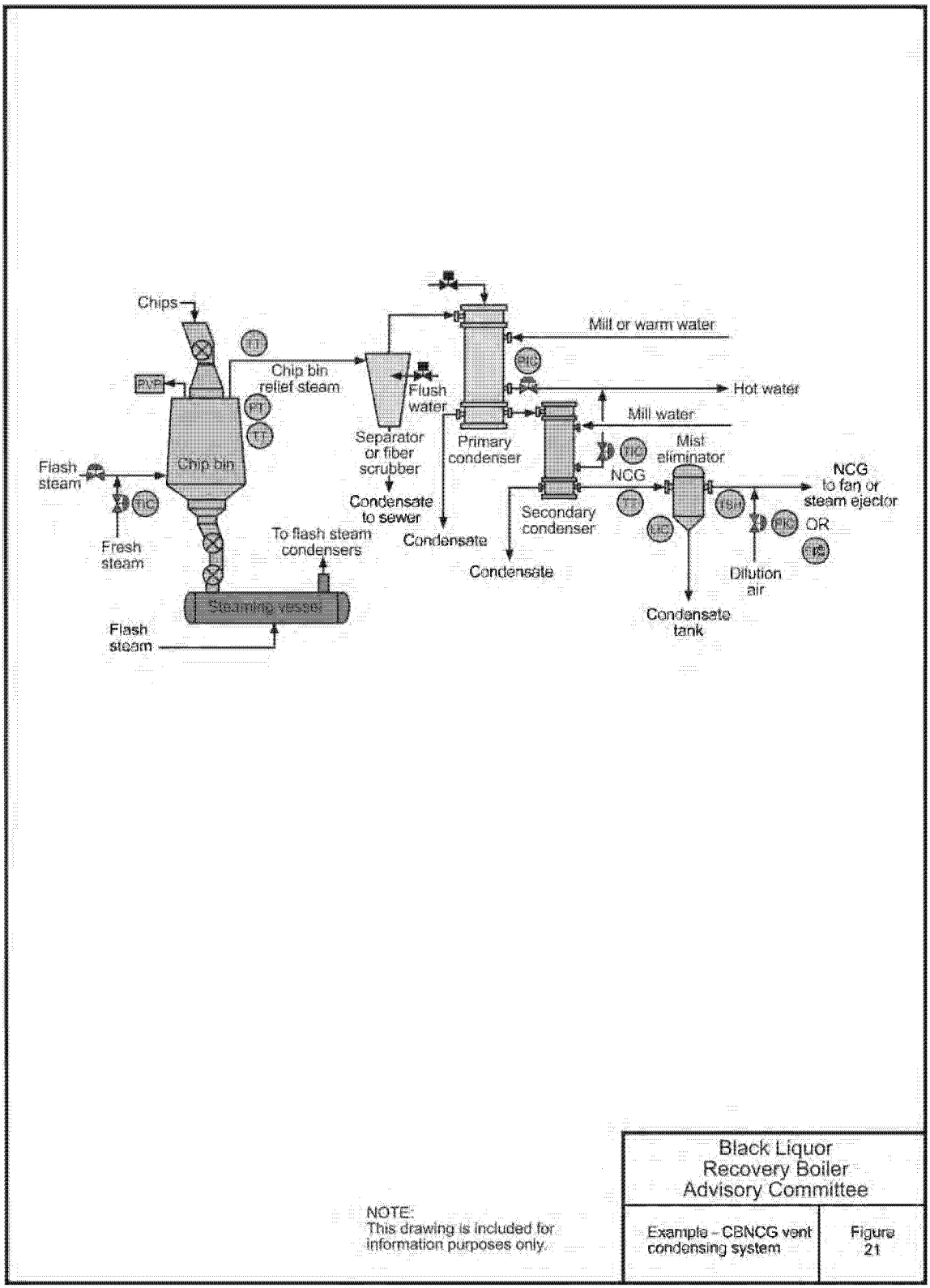

Figure 21 Example - CBNCG vent condensing system.

8.2.3 Chip Bin NCG Transfer System

Mills may elect to transfer Chip Bin NCG using a spark-resistant fan as is typically employed for conventional DNCG systems; however, continuous monitoring of % LEL is recommended if risk factors indicate a high likelihood of generating flammable gas concentrations during upset conditions. Particular attention should be given to ensure that the casing and shaft are well-grounded and that frequent or continuous vibration monitoring is performed in order to minimize the risk of the Fan becoming a source of ignition.

A steam ejector is recommended for systems where the possibility of developing flammable gas concentrations is high. Potential ignition by the centrifugal fan is avoided. The ejector steam, as with CNCG systems, serves to dilute both the flammable gas concentration as well as the oxygen.

The relative volume of a separately handled Chip Bin vent collection system, whether conveyed by steam ejector or by fan, however, is considerably smaller than typical DNCG systems and affords added flexibility with disposal in the Recovery Boiler. Pre-heating is, therefore, not a requirement. Figures 20 and 21 show typical Fan and Steam Ejector delivery systems.

Steam Ejector systems - Steam-ejected Chip Bin NCG can be added to the same burner as that used for burning CNCG and SOG, by adding another annulus.

Advantages:

- Provides steam dilution of both oxygen and NCG concentration
- Steam vs Electrical when energy cost is favorable
- May provide a flame quenching point
- No moving parts
- Offers no source of ignition

Disadvantages:

- Steam consumption
- Contributes moisture to point of incineration [Condensing Ejector steam results in losing several key advantages regarding NCG flammability.]
- High pressure steam needs to be below auto-ignition point of 400F.
- Discharge pressure protection is required.

The NCG may also be injected directly into the Boiler at high velocity (e.g., > 50 fps) through one or two tertiary ports.

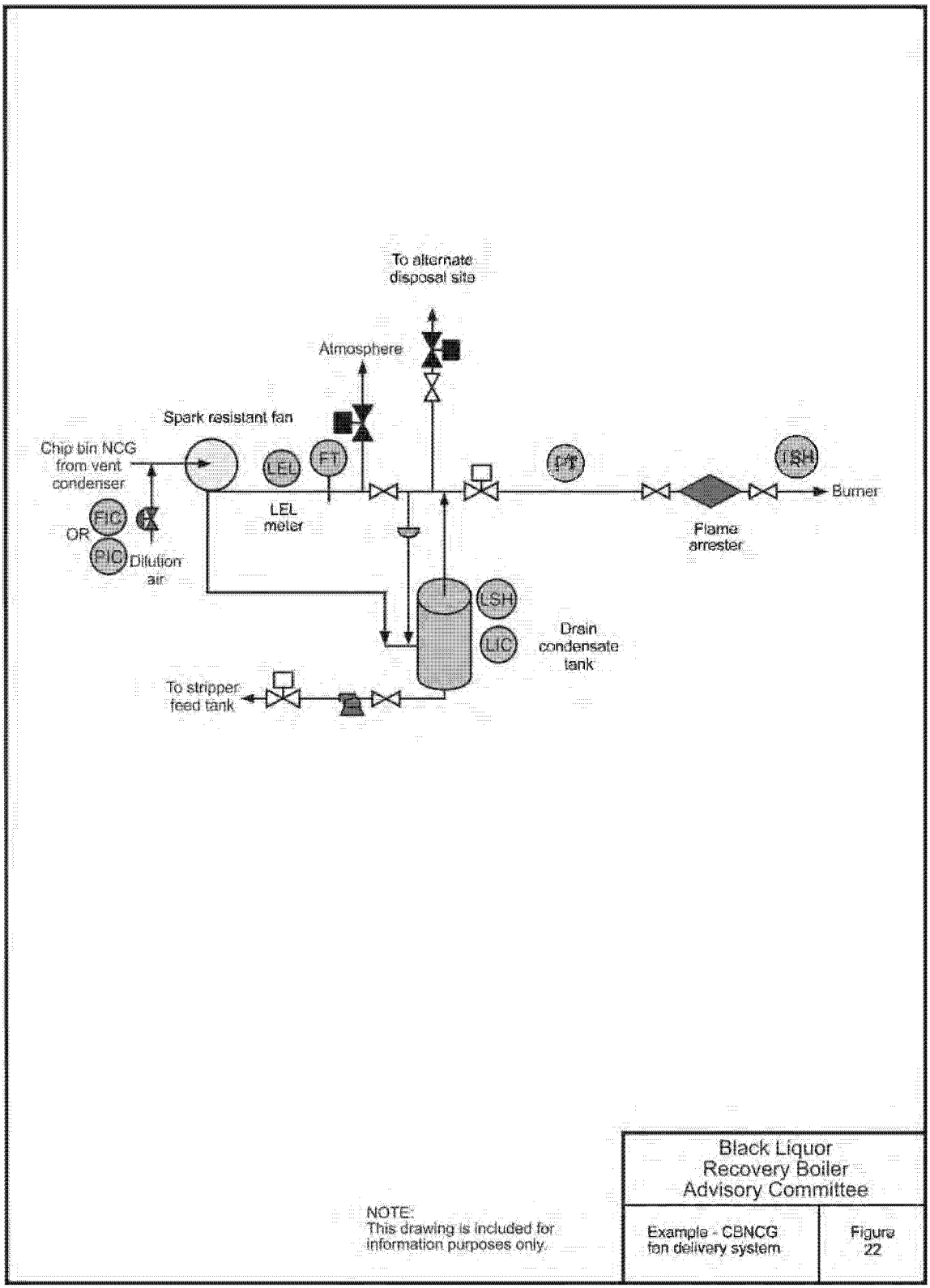

Figure 22 Example - CBNCG fan delivery system.

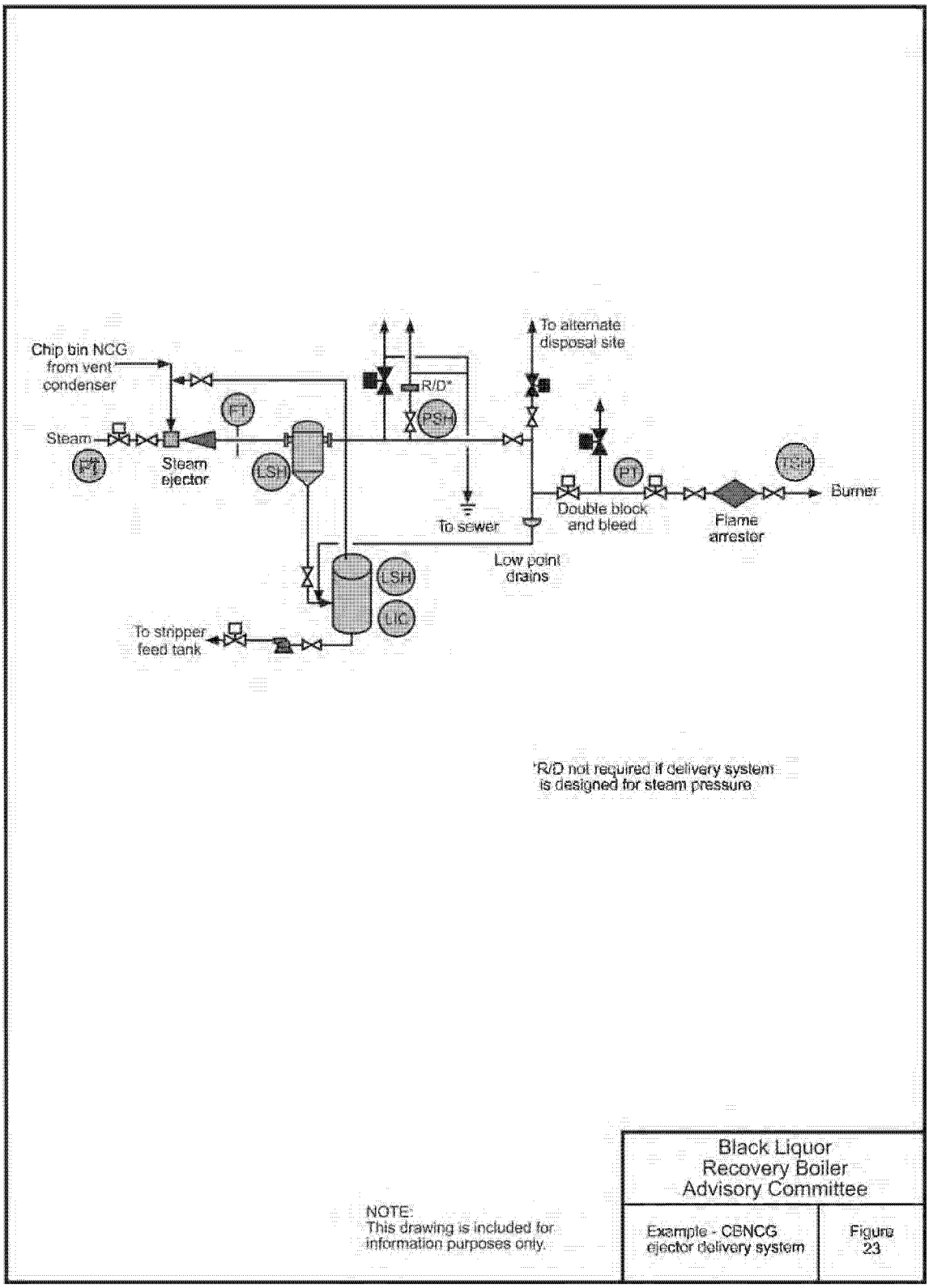

Figure 23 Example - CBNCG ejector delivery system.

Fan systems – Fan conveyed CBNCG may be handled similarly in that the CNCG burner requirement for combustion air can be satisfied by the Chip Bin flow. Use of an auxiliary combustion air supply would still be required should the Chip Bin flow be diverted.

Advantages:

- Dry delivery of NCG to incineration
- Electrical vs Steam when energy cost is favorable
- Discharge pressures are not potentially high – no pressure relief device to maintain

Disadvantages:

- Can be a source of ignition
    - Foreign material
    - Mechanical failure (worn bearing)
    - Inadequate grounding (case or shaft)
- Additional air is typically required for balancing
- Unless fresh steam is used, an LEL Meter is recommended.
- Added number of interlocks
- Increased frequency of venting likely

Fan Design Considerations

- Spark-resistant metallurgy (typically monel) at potential contact points.
- Fan and Shaft grounding with periodic confirmation
- Continuous bearing temperature monitoring
- Continuous vibration monitoring
- Condensate draining provisions
- Provide dilution ahead of Fan, but after the Vent Condenser.
- Provide an LEL Meter after Fan with sample probe protected from entrained condensate.

This NCG flow may also be introduced directly into the Boiler at high velocity (e.g., > 50 fps) through one or two separate ports.

8.2.4 CBNCG Piping System and Auxiliary Equipment

Gas piping should be designed to prevent accumulation of condensates. Where possible, piping should be sloped in the direction of gas flow to facilitate draining and to minimize accumulation of tar deposits.

Gas piping should be grounded at several locations along the collection system.

For fan-based systems, refer to Section 4.2.5 covering DNCG piping; for Steam Ejector-based systems, refer to Section 5.2.3 covering CNCG piping.

Separate condensate collection systems are preferred; however, CBNCG and DNCG systems may share common condensate drain collection tanks **except** where upset

pressure differences can interfere with system operation or the integrity of lockout/tagout procedures is compromised.

8.3 Monitoring and Control

Monitoring and control of the CBNCG system should include indication and response to upset Chip Bin operation. Fan-based delivery systems present the greatest risk for fire and explosions unless adequate interlock protection is provided.

Monitoring should include indication of low Chip Bin level, abnormally high top Chip Bin temperature; lower than normal top Chip Bin temperature and high vent condenser NCG temperature. Fan-based systems that transport CBNCG from flash steam pre-steaming or wood species that contain volatile oils are subject to higher risk of developing flammable NCG conditions. LEL monitoring should be seriously considered as well as frequent/continuous monitoring of fan vibration and bearing temperature.

8.4 Safety System

CBNCG is not considered a fuel. It is considered as "malodorous air" for fan-delivered systems that include added dilution air. Steam-ejected delivery systems will generally transport only the air that enters at the Chip Bin and that air's contribution to combustion air requirements, in a properly designed and operated system, will likely be small.

Since upsets at the Chip Bin are primarily responsible for conditions that affect the flammability and hazardous nature of CBNCG, process stability is reflected in the logic for burning CBNCG in the Recovery Boiler.

An LEL meter is not required, but use of an LEL meter can provide a more accurate indication of combustible content than surrogate parameters. All interlocks must be included but an LEL meter that is calibrated and operating properly can be functionally substituted for the surrogate parameters in the tripping logic.

For either method of delivery, direct injection is preferred at nozzle velocities > 50 fps.

8.4.1 Permissive Starting Logic – CBNCG – Fan Delivery

To admit CBNCG to the Recovery Boiler, the following conditions should be fulfilled:

- Purge credit established and maintained
- Steam flow is above 30% of MCR
- Drain Collection Tank levels not high
- CBNCG flow is proven*
- Fan vibration levels not high
- Chip Bin level not low**
- Chip Bin top temperature not high**
- Chip Bin top temperature not low**

- %LEL not high (if used)
- CBNCG temperature after Vent Condenser not high**
- CBNCG delivery pressure not low
- CBNCG delivery pressure not high

Permissive starting logic for thermal oxidation of CBNCG is shown in Figure 22.

8.4.2 Protective Tripping Logic – CBNCG – Fan Delivery

Any of the following conditions will divert CBNCG from the Recovery Boiler:

- Master Fuel Trip (purge credit lost)
- CBNCG pressure low or high
- CBNCG flow low*
- Gas temperature after Chip Bin Vent Condenser high**
- Chip Bin top temperature increasing after being low**
- CBNCG temperature at nozzle high
- CBNCG fan vibration level high
- %LEL high (if used)
- Boiler steam flow less than 30% of MCR
- Shut-off valve to alternative control device not closed (if applicable)
- Automatic vent valve not closed.
- Drain collection tank level high
- Manual switch to vent valve activated

Protective tripping logic for thermal oxidation of CBNCG is shown in Figure 23.

* Flow can be proven with pressure, flow, temperature, fan operating and control damper position (fan operation should be proven with shaft speed), or other means. Note that pressure alone could indicate pluggage rather than flow.

**Interlocks typically part of Digester controls.

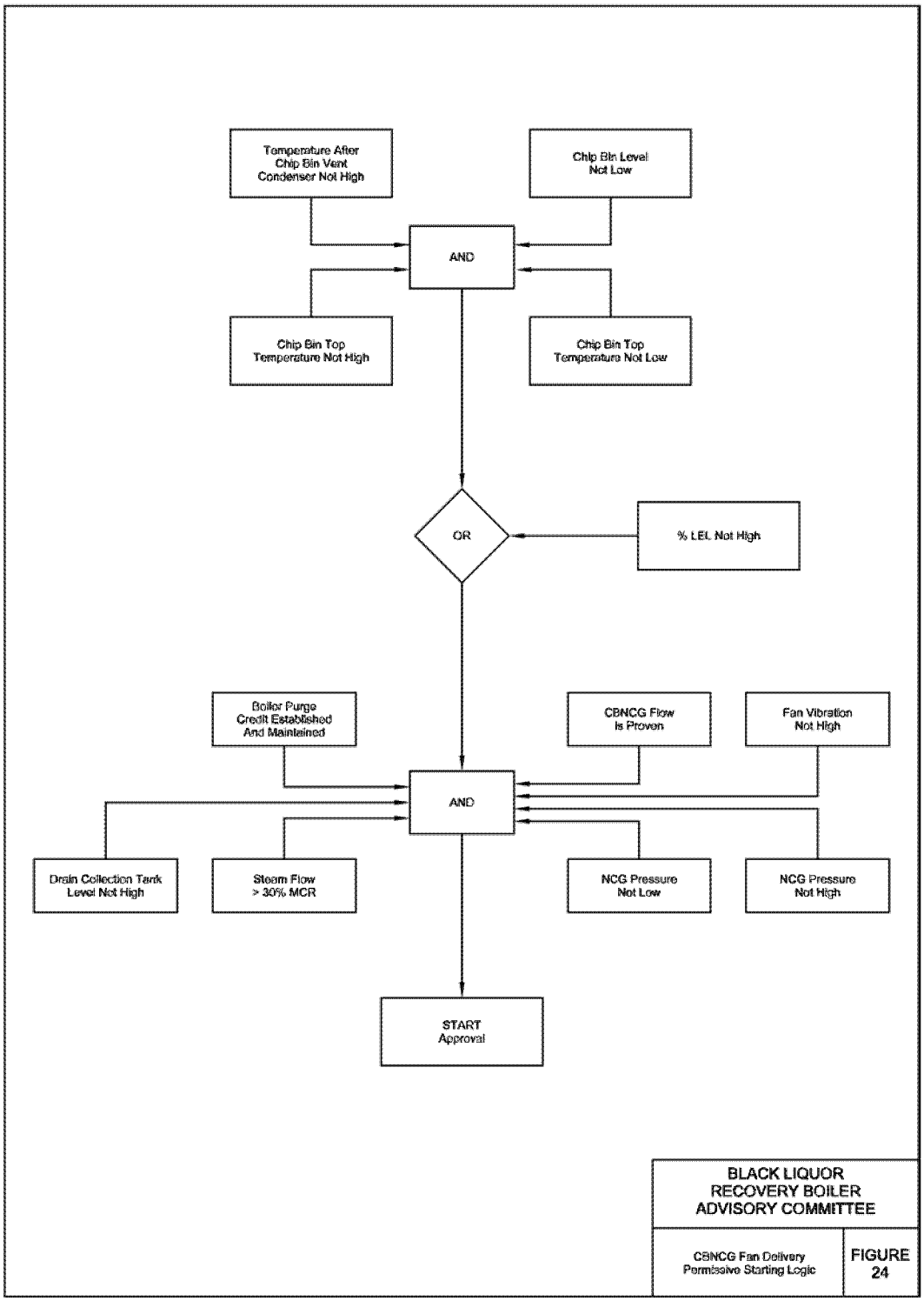

Figure 24 CBNCG Fan Delivery Permissive Starting Logic.

Table 11 Explanation Chart for CBNCG Injection Permissive Starting Logic - Fan Delivery for Figure 24

LOGIC BLOCK	PURPOSE	HAZARD PROTECTED
Boiler Purge Credit Maintained (From Figure 21 'Common Permissive Starting Logic' in Safe Firing of Auxiliary Fuel Recommended Good Practice)	Stop DNCG introduction when boiler firing permissives not met	Prevent introduction of DNCG while boiler is not being fired.
Steam Flow >30% MCR	Ensure furnace combustion is stable.	Unstable operation of boiler may minimize furnace residence time or provide too low a temperature for proper oxidation.
Drain Collection Tank levels not high.	Prevent condensate from flooding NCG duct.	Prevent condensate from entering boiler.
CBNCG flow established*	Ensure sufficient motive force and dilution	Provide minimum line and nozzle entry velocity to prevent flame propagation
Fan vibration levels not high	Indicates potential spark generation	Prevent ignition of flammable gas
Chip Bin level not low**	Indicates potential breakthrough of flammable gas	Prevent NCG from exceeding 100% LEL with explosion hazard
Chip Bin top temperature not high**	Possible breakthrough of flammable gas	Prevent NCG from exceeding 100% LEL
Chip Bin top temperature, not low**	Avoid a surge of revaporized flammable gas as chip bin warms up	Prevent CBNCG from becoming explosive
CBNCG after Vent Condenser not high**	Ensure adequate condensing of terpenes	Prevent NCG from exceeding 100% LEL
% LEL not high**	Indicates gas is not flammable	Prevent injection of flammable gas
CBNCG delivery pressure not low	Ensure sufficient motive force	Provide minimum line and nozzle entry velocity to prevent flame propagation
CBNCG delivery pressure not high	System is not plugged or flooded	Provide minimum line and nozzle entry velocity to prevent flame propagation. Prevent blowing loop seals and rupture discs.
Start Approval	Start permissive after satisfying interlocks	Interlocks made.

* Flow can be proven with flow indication or surrogate measures, including fan shaft speed.
** Typically part of Digester interlock controls and not part of boiler permissives

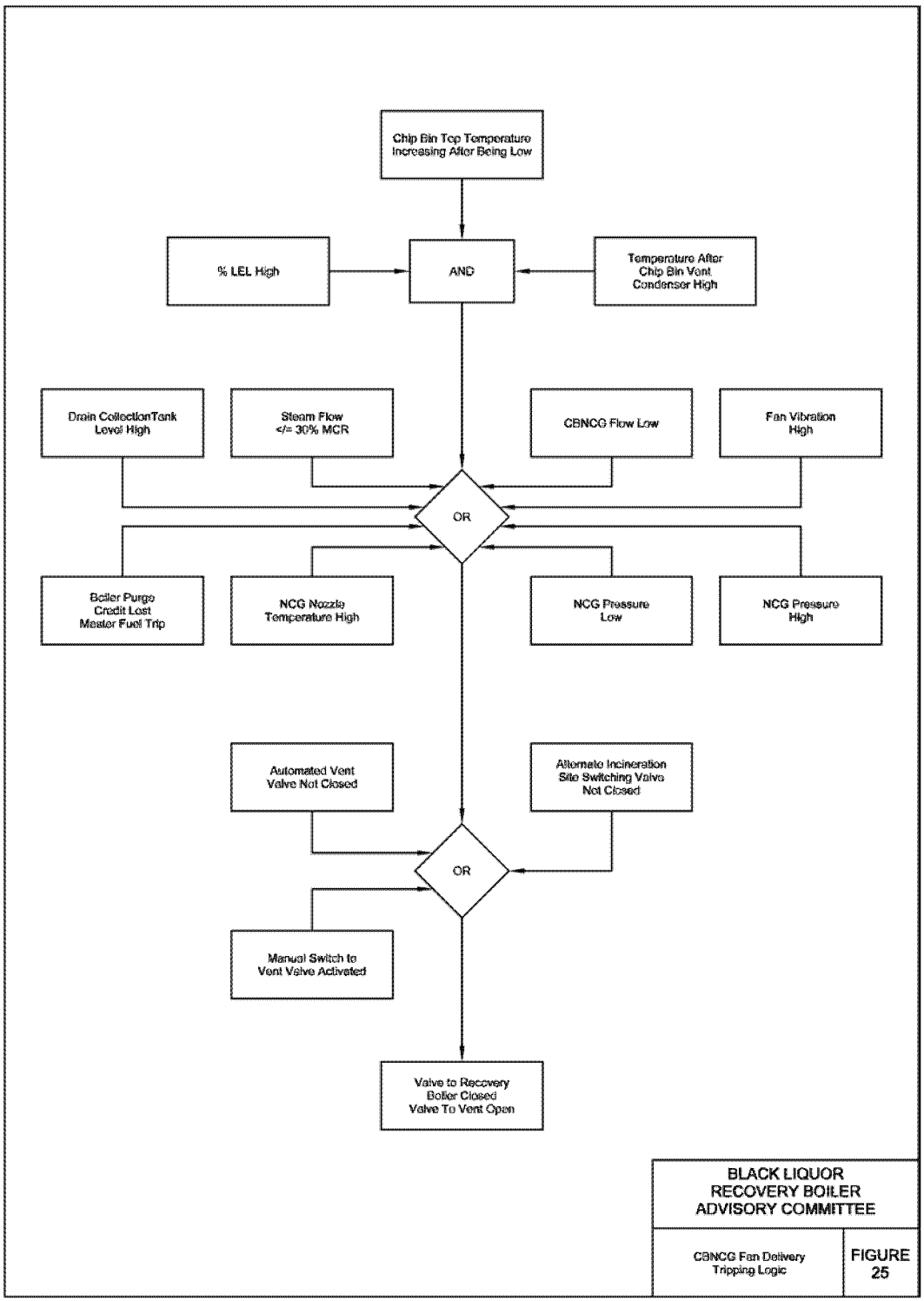

Figure 25 CBNCG Fan Delivery Tripping Logic.

Table 12 Explanation Chart for CBNCG Injection Protective Tripping Logic - Fan Delivery for Figure 25

LOGIC BLOCK	PURPOSE	HAZARD PROTECTED
Boiler Purge Credit Lost Master Fuel Trip (From Figure 21 'Common Permissive Starting Logic' in Safe Firing of Auxiliary Fuel Recommended Good Practice)	Stop DNCG introduction when boiler firing permissives not met	Prevent introduction of DNCG while boiler is not being fired.
Steam Flow <30% MCR	Furnace combustion may be unstable.	Unstable operation of boiler may minimize furnace residence time or provide too low a temperature for proper oxidation.
Drain Collection Tank levels high.	Condensate may be flooding NCG duct.	Prevent condensate from entering boiler.
CBNCG flow low*	Ensure sufficient motive force	Provide minimum line and nozzle entry velocity to prevent flame propagation
Fan vibration levels high	Indicates potential spark generation	Prevent ignition of flammable gas
Chip Bin level low**	Indicates potential breakthrough of flammable gas	Prevent NCG from exceeding 100% LEL with explosion hazard
Chip Bin top temperature high**	Possible breakthrough of flammable gas	Prevent NCG from exceeding 100% LEL
Chip Bin top temperature increasing after being low**	Avoid a surge of revaporized flammable gas as chip bin warms up	Prevent CBNCG from becoming explosive
CBNCG after Vent Condenser high**	Possible inadequate condensing of terpenes	Prevent NCG from exceeding 100% LEL
% LEL high**	Indicates gas may be flammable	Prevent injection of flammable gas
CBNCG delivery pressure low	insufficient motive force or dilution	Provide minimum line and nozzle entry velocity to prevent flame propagation
CBNCG delivery pressure high	System may be plugged or flooded	Provide minimum line and nozzle entry velocity to prevent flame propagation. Prevent blowing loop seals and rupture discs.

(continued)

Table 12. (cont'd) Explanation Chart for CBNCG Injection Protective Tripping Logic – Fan Delivery for Figure 25

LOGIC BLOCK	PURPOSE	HAZARD PROTECTED
NCG Nozzle temperature high	Indicate flameback	Prevent explosion in line
Manual switch to vent valve activated	Remove foul gas from boiler	Boiler conditions such that continued NCG delivery creates an unsafe condition.
Automated vent valve not closed	Confirm valves in proper Position to prevent flow to more than one location	Provide minimum line and nozzle entry velocity to prevent flame propagation.
Valves to alternate location not closed	Confirm valves in proper Position to prevent flow to more than one location	Provide minimum line and nozzle entry velocity to prevent flame propagation.

* Flow can be proven with flow indication or surrogate measures, including fan shaft speed.
** Typically part of Digester interlock controls and not part of boiler permissives

8.4.3 Permissive Starting Logic – CBNCG – Steam Ejector Delivery

To admit CBNCG to the Recovery Boiler, the following conditions should be fulfilled:

- Purge credit established and maintained
- Steam flow is above 30% of MCR
- Drain Collection Tank levels not high
- Ejector steam or discharge flow not low
- Chip Bin level not low*
- Chip Bin top temperature not high*
- Chip Bin top temperature not low*
- %LEL not high (if used)*
- CBNCG temperature after Vent Condenser not high*
- CBNCG delivery pressure not low
- CBNCG delivery pressure not high

Permissive starting logic for thermal oxidation of CBNCG is shown in Figure 24.

8.4.4 Protective Tripping Logic – CBNCG – Steam Ejector Delivery

Any of the following conditions will divert CBNCG from the Recovery Boiler:

- Master Fuel Trip (purge credit lost)
- CBNCG delivery pressure low
- CBNCG delivery pressure high
- Drain Collection Tank level high
- CBNCG Ejector steam or discharge flow low
- CBNCG temperature at nozzle high
- Gas temperature after Chip Bin Vent Condenser high*
- Chip Bin top temperature increasing after being low*
- %LEL high (if used)*
- Boiler steam flow less than 30% of MCR
- Shut-off valve to alternative control device not closed (if applicable)
- Automatic vent valve not closed.
- Manual switch to vent valve activated

* Consider these as Digester source interlocks or alarms, but not permissives for the Boiler.

Protective tripping logic for thermal oxidation of CBNCG is shown in Figure 25.

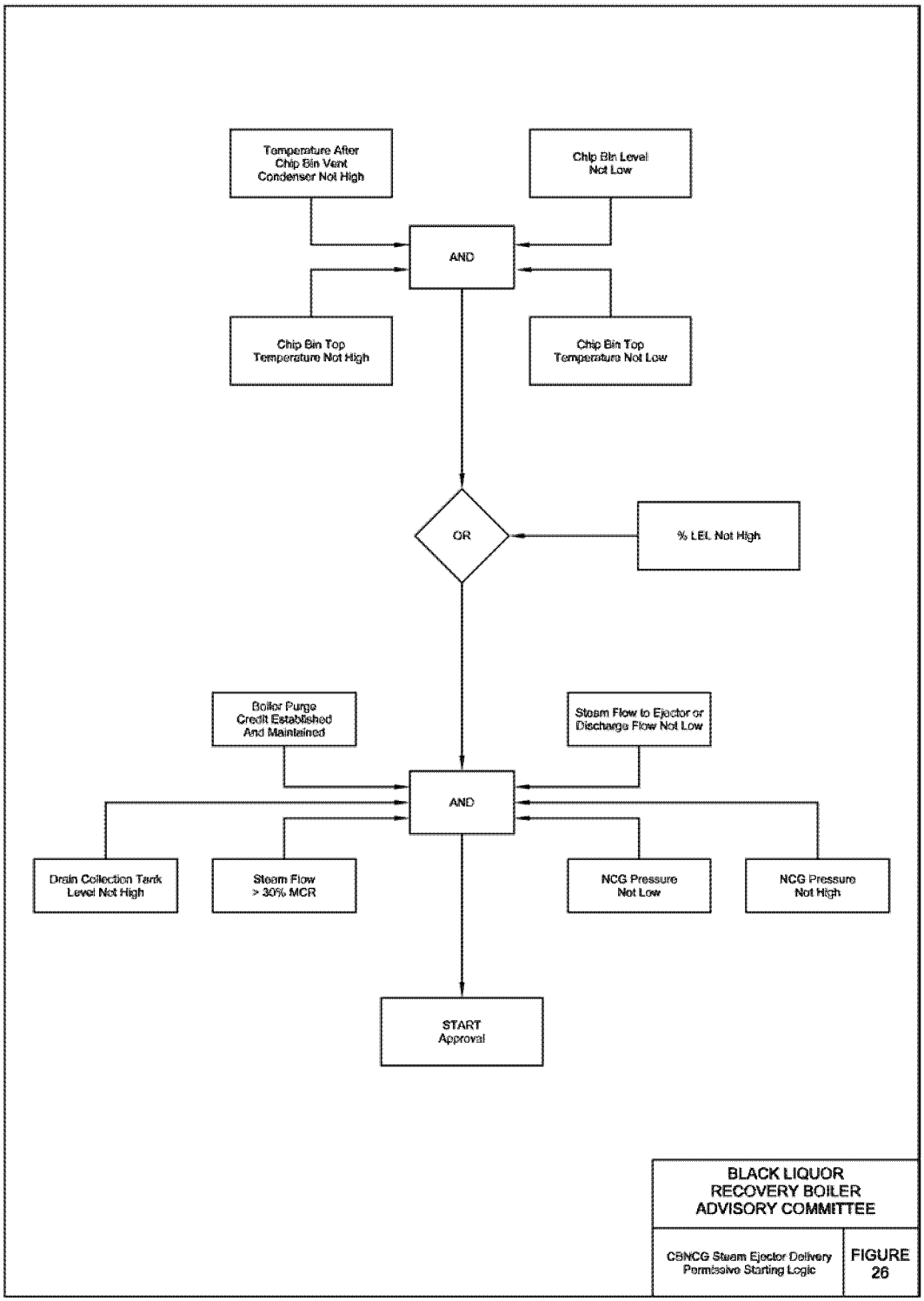

Figure 26 CBNCG Steam Ejector Delivery Permissive Starting Logic.

Table 13 Explanation Chart for CBNCG Injection Permissive Starting Logic - Steam Ejector Delivery for Figure 26

LOGIC BLOCK	PURPOSE	HAZARD PROTECTED
Boiler Purge Credit Maintained (From Figure 21 'Common Permissive Starting Logic' in Safe Firing of Auxiliary Fuel Recommended Good Practice)	Stop DNCG introduction when boiler firing permissives not met	Prevent introduction of DNCG while boiler is not being fired.
Steam Flow >30% MCR	Ensure furnace combustion is stable.	Unstable operation of boiler may minimize furnace residence time or provide too low a temperature for proper oxidation.
Drain Collection Tank levels not high.	Prevent condensate from flooding NCG duct.	Prevent condensate from entering boiler.
Ejector Steam flow or discharge flow not low	Ensure minimum line velocity and gas dilution	Provide minimum line and nozzle entry velocity to prevent flame propagation.
Chip Bin level not low**	Indicates potential breakthrough of flammable gas	Prevent NCG from exceeding 100% LEL with explosion hazard
Chip Bin top temperature not high**	Possible breakthrough of flammable gas	Prevent NCG from exceeding 100% LEL
Chip Bin top temperature not low**	Avoid a surge of revaporized flammable gas as chip bin warms up	Prevent CBCG from becoming explosive
CBNCG after Vent Condenser not high**	Ensure adequate condensing of terpenes	Prevent NCG from exceeding 100% LEL
% LEL not high**	Indicates gas is not flammable	Prevent injection of flammable gas
CBNCG delivery pressure not low	Ensure sufficient motive force	Provide minimum line and nozzle entry velocity to prevent flame propagation
CBNCG delivery pressure not high	System is not plugged or flooded	Provide minimum line and nozzle entry velocity to prevent flame propagation. Prevent blowing loop seals and rupture discs.
Start Approval	Start permissive after satisfying interlocks	Interlocks made.

* Flow can be proven with flow indication or surrogate measures, including fan shaft speed.
** Typically part of Digester interlock controls and not part of boiler permissives

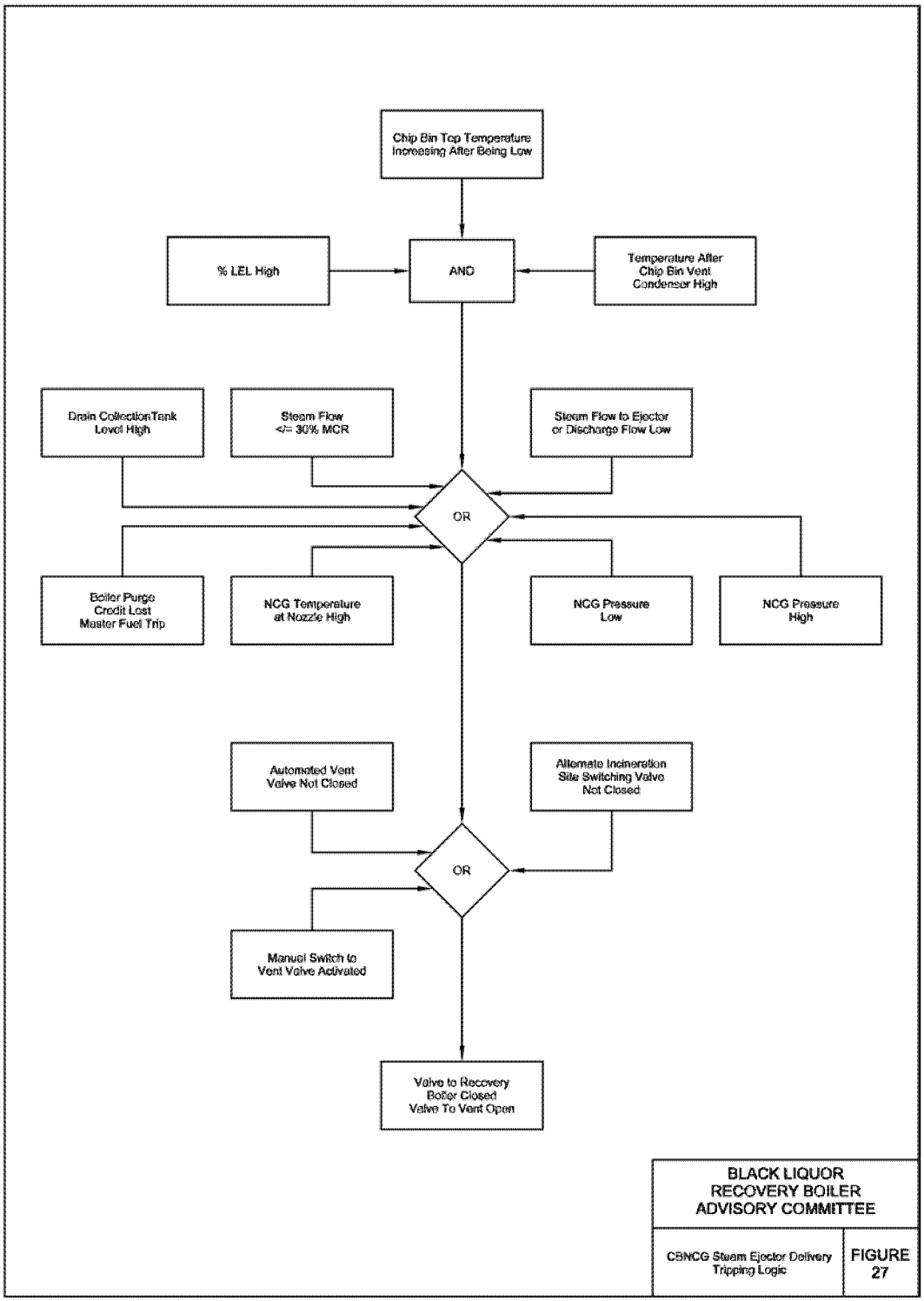

Figure 27 CBNCG Steam Ejector Delivery Tripping Logic.

Table 14 Explanation Chart for CBNCG Injection Protective Tripping Logic - Steam Ejector Delivery for Figure 27

LOGIC BLOCK	PURPOSE	HAZARD PROTECTED
Boiler Purge Credit Lost Master Fuel Trip (From Figure 21 'Common Permissive Starting Logic' in Safe Firing of Auxiliary Fuel Recommended Good Practice)	Stop DNCG introduction when boiler firing permissives not met	Prevent introduction of DNCG while boiler is not being fired.
Steam Flow <30% MCR	Furnace combustion may be unstable.	Unstable operation of boiler may minimize furnace residence time or provide too low a temperature for proper oxidation.
Drain Collection Tank levels high.	Condensate may be flooding NCG duct.	Prevent condensate from entering boiler.
Ejector Steam flow or discharge flow low	Loss of motive force, line velocity and gas dilution	Provide minimum line and nozzle entry velocity to prevent flame propagation.
Chip Bin top temperature increasing after being low**	Avoid a surge of revaporized flammable gas as chip bin warms up	Prevent CBNCG from becoming explosive
CBNCG after Vent Condenser high**	Possible inadequate condensing of terpenes	Prevent NCG from exceeding 100% LEL
% LEL high**	Indicates gas may be flammable	Prevent injection of flammable gas
CBNCG delivery pressure low	Insufficient motive force	Provide minimum line and nozzle entry velocity to prevent flame propagation
CBNCG delivery pressure high	System may be plugged or flooded	Provide minimum line and nozzle entry velocity to prevent flame propagation. Prevent blowing loop seals and rupture discs.
NCG Nozzle temperature high	Indicate flameback	Prevent explosion in line
Manual switch to vent valve activated	Remove foul gas from boiler	Boiler conditions such that continued NCG delivery creates an unsafe condition.

(continued)

Table 14. (cont'd) Explanation Chart for CBNCG Injection Protective Tripping Logic – Steam Ejector Delivery for Figure 27

Automated vent valve not closed	Confirm valves in proper Position to prevent flow to more than one location	Provide minimum line and nozzle entry velocity to prevent flame propagation.
Valves to alternate location not closed	Confirm valves in proper Position to prevent flow to more than one location	Provide minimum line and nozzle entry velocity to prevent flame propagation.

* Flow can be proven with flow indication or surrogate measures, including fan shaft speed.
** Typically part of Digester interlock controls and not part of boiler permissives

8.5 Personnel Safety

Characteristics for CBNCG and personnel safety considerations are described in Sections 4.5 for DNCG and 5.5 for CNCG.

APPENDIX A DOCUMENT REVISION HISTORY

October 2010

1. Foreword: Deleted in its entirety. A portion was adapted for inclusion in Chapter 1.
2. Chapter 1
    a. Editorial/non-technical changes.
    b. The paragraph stating BLRBAC discourages the burning of waste streams in recovery boilers has been deleted.
3. Chapter 2: Numerous definitions added, deleted, or revised.
4. Chapter 3: Primarily editorial with changes to distinguish SOG form other CNCG waste streams and to accommodate the addition of liquid waste stream incineration in the scope of the document.
5. Chapter 4:
    a. Guidelines for idle DNCG line has been added along with other primarily editorial changes.
    b. Deleted unnecessary logic blocks after "START Approval" in Figure 2, DNCG Permissive Starting Logic.
6. Chapter 5: Primarily editorial changes and:
    a. Clarification on the location of flame arrestors in CNCG and SOG lines
    b. Explanation for recommendation to keep SOG separate from other CNCG
    c. Corrections to Tables 6 and 7 to match the logic blocks in their respective figures.
    d. Fig. 5: Terminology changed from "LP Steam" to "Purge Steam" and "MP Steam" to "Ejector Steam". Also revised to show automatic vent line coming off top CNCG and SOG supply lines.
    e. Fig. 6: Flame arrestor location in CNCG and SOG lines moved for consistency with text. Also revised to show automatic vent lines coming off top CNCG and SOG supply lines.
7. Chapter 6: Section 6.7 has been completely rewritten to provide guidelines on the blending of turpentine and red oil into the black liquor. New Figures 19 and 20 have been added for permissive starting and tripping interlock logic for turpentine. (Subsequent figures renumbered accordingly.) Other editorial changes were made in earlier sections of the chapter for consistency with section 6.7.

October 2008

- Chapter 5 revised to address purging of the portion of the CNCG supply line to the recovery boiler between the final/most downstream shutoff valve and the burner.

- Added a new chapter 8, Guidelines for Thermal Oxidation of Chip Bin NCG and revised Chapter 4 to delete guidance on the incineration of chip bin NCGs.

April 2008

- Chapter 4, Guidelines for Thermal Oxidation of DNCG
  - Added guidelines for the safe incineration of recovery boiler dissolving tank vent gases that includes a recommendation for handling dissolving tank vent gases independently of any other NCG system. This material is dispersed throughout the chapter as needed in each of the sections including modifications to Figures 2 and 3 and their associated logic explanation charts and the addition of a new Figure 4, DNCG Transfer System for Dissolving Tank Vent.
  - Section 4.2.4, DNCG Transfer System:
    - Added a recommendation that the entire transport system be grounded.
    - Modified the low point drain recommendation to specifically recommend the fan casing have a condensate outlet at its lowest point.
    - Added a recommendation for high and low temperature alarms for gas condensers/preheaters.
    - Clarified DNCG gas temperature conditioning equipment.
    - Added a recommendation that all vent lines for DNCG systems be routed to a safe location.
  - Section 4.2.5, DNCG Piping System and Auxiliary Equipment:
    - Added a recommendation for sloped piping with a low point drain.
    - Added a recommendation that position switches on automatic valves provide feedback to a manned control room.
  - Section 4.3, Monitoring and Control
    - Added a recommendation for routine monitoring of bearing temperature and vibration.
    - Added recommended maximum design % LEL values with and without automatic interlocks.
  - In the logic explanation table for Figure 3, the "Purpose" and "Hazard Protected" were added for the "Switch DNCG from boiler to vent" Logic Block.

- Added a new Chapter 7, Guidelines for Thermal Oxidation of Liquid Waste Streams in Dedicated Burners.

<u>October 2006</u>

- Section 4.2.2 – Changed "vented to atmosphere" to "diverted."
- Section 4.2.3
  - Added "relative" to text so as to read: "50% relative humidity."
  - Added explanation for recommended double block and vent.
- Sections 4.4.1 & 4.4.2, Figure 2 and accompanying Logic Explanation Chart, and Figure 3 and accompanying Logic Explanation Chart – Permissive starting logic and protective tripping logic modified to recognize a variety of means are available to detect DNCG flow.
- Section 5.1.3 – Igniter design recommendation for waste stream burner modified to specifically refer to NFPA class 1 continuous igniters.
- Section 5.2.3 – Removed reference to specific piping design codes and added that piping must meet the required service conditions and be acceptable to the authorities having jurisdiction.

- Added Chapter 6, *Liquid Waste Streams Blended with Black Liquor*

April 2002

This document has been revised to provide a consistent format. With the exception of an added sentence in Section 4.2.1, there are no technical changes from the prior issue.

October 1999

First issue.

Attachment 4

Attachment C, NCASI, Experience with the Collection, Transport, and Burning of Kraft Mill High Volume Low Concentration Gases, August 2003

Note to Docket

EPA–HQ–OAR–2007-0544

This attachment contains copyrighted material and has been removed from the document.

Attachment 5

Attachment D, FM Global, Property Loss Prevention Data Sheets, January 2012

Note to Docket

EPA–HQ–OAR–2007-0544

This attachment contains copyrighted material and has been removed from the document.

Attachment 6

Attachment E, FM Global, Property Loss Prevention Data Sheets, May 2010

Note to Docket

EPA–HQ–OAR–2007-0544

This attachment contains copyrighted material and has been removed from the document.

Attachment 7

Attachment F, FM Global, Property Loss Prevention Data Sheets, May 2006

Note to Docket

EPA–HQ–OAR–2007-0544

This attachment contains copyrighted material and has been removed from the document.

Attachment 8

Cost Estimate for Elimination of Excess Emission Allowances, June 2012

Attachment 8
Cost Estimate for Elimination of Excess Emission Allowances
40 CFR 63 Subpart S

Introduction

If the excess emission provisions are eliminated, facilities could choose to implement the following upgrades/additions to their systems: (1) Route HVLC gases to a back-up control device, (2) Upgrade or replace the gas collection systems (LVHC/HVLC), and/or (3) Install a back-up steam stripper at a total cost of $750 M. While it is expected that installation of these systems could reduce the number and duration of excess emission events, they will not eliminate all events. As noted in Attachment 1, the NCG gas collection systems are complex systems under pressure that must be designed to meet safety and insurance standards. Even the best performing systems are subject to these events and these allowances are a result of the MACT floor development. Steam strippers must be maintained and these activities require downtime of the control device. Again, this was recognized during development of the MACT floor which resulted in a downtime allowance for these control devices. While facilities could incur capital expenditures in an effort to try to minimize these events, elimination of the allowances would create a scenario in which no mill could meet the standards.

Cost Estimate

The following tables outline the assumptions and capital cost estimates for the industry to install redundant systems. A more detailed table is provided at the end of this section. Although there will be increased O&M for these systems, those costs are not included in this analysis. In addition, it is assumed that EPA will not require additional collection and treatment of condensates and therefore mills will still be able to utilize the CCA compliance approach.

Capital Cost Estimate for Redundant Systems

	Capital Cost/Unit
Route HVLC Systems to a Backup Control Device	$ 5 M
Upgrade existing HVLC/LVHC Collection Systems	$ 2 M
Replace existing HVLC/LVHC Collection Systems	$ 7.5 M
Install Back-up Steam Strippers	$ 7.4 M

These costs were developed based on the following assumptions:

Assumptions	Number of Units Affected	Capital Cost
Route HVLC Systems to a Backup Control Device	28	$ 100 M
Upgrade existing HVLC/LVHC Collection Systems	73	$ 150 M
Replace existing HVLC/LVHC Collection Systems	24	$ 200 M
Install Back-up Strippers	44	$ 300 M
TOTAL		**$ 750 M**

Route HVLC Systems to a Backup Control Device

- Assume that 28 facilities (97 facilities less the 35 that demonstrated compliance using the CCA approach without collecting any HVLC gases and less an estimated 34 facilities that already have a back-up control device) will need to have HVLC gases routed to a backup incineration device.
- As noted, it is assumed that the final rule will maintain the treatment efficiency requirements at 92% and 10.2 and 6.6 lb/ADUBTP (bleached/unbleached). Therefore, facilities that utilized the CCA approach can maintain their systems and will not need to collect HVLC systems that are currently uncollected.
- These costs are only for the ductwork and supporting materials/systems to route the main HVLC trunk line to a backup control device and assume that a backup incineration device is available (i.e., no new incinerator, oxidizer, etc.).
- The HVLC control cost of $5 M per facility is based on member input for recent costs to route HVLC gases to a back-up control device

Upgrade/Replace existing HVLC/LVHC Collection Systems

- These costs assume all 97 facilities will need to either upgrade or replace their existing HVLC/LVHC collection systems. Of these it is assumed 25% will need to replace their systems while the remaining 75% will only need to upgrade.
- System upgrades are estimated at $2 M per facility and could include the costs for redundant flame arrestors, to overdesign and upgrade condensers, etc.
- The cost of $7.5 M per facility for system replacements is based on member input for the cost to install these systems for MACT I Phase I which ranged from $5 – 10 M.

Install Back-up Strippers

- These costs assume that all 43 facilities that utilize only a steam stripper for compliance will need to install a back-up unit. Systems that also utilize their biological treatment system for compliance will not need to install back-up steam strippers. One facility has a stand-alone biological treatment system and it is assumed this facility will need to install a back-up stripper.
- The cost of $7.4 M per units is based on a cost estimate for a stand-alone stripper installation for member company in 1998 dollars adjusted to 2012 dollars.

Redundant Collection and Treatment Systems Will Not Eliminate Venting

However, even if facilities upgrade or replace their collection systems and install or provide access to back-up treatment systems, it is believed that these measures will not eliminate all venting episodes.

LVHC & HVLC Venting

The top four causes of LVHC venting are due to:

- Primary Control Device being Unavailable,
- Pressure / Temperature Interlocks in Gas Transport System,
- Pressure / Temperature Parameters on Process Equipment Outside Normal Operating Ranges, and
- Switching between Incineration Points.

The top three reasons for HVCL events are also similar to the top three reasons for LVHC events. However, elimination of these events is not guaranteed by upgrading or replacing the gas collection systems and routing gases to a back-up HVLC control device (most LVHC systems already have a backup control device). When the primary control device is unavailable either due to a system trip or maintenance activities, the facility's only option for treatment is the back-up control device. In the case of a primary treatment system trip, the facility must switch to the back-up control device. It is noted that even "ventless" transfer systems must have a short term vent when switching between devices for safety reasons (steam purge the line). In the case where the primary treatment device is unavailable for maintenance reasons, if conditions prohibit the backup control device from accepting the LVHC gases, the system will vent. In addition to these two circumstances, most facilities will purposely switch between LVHC control devices on a regular frequency (typically once per week) to test the transfer system. As noted, these switches cannot always be ventless. While installation of a back-up control device would help minimize HVLC vents, these systems will have the same challenges as LVHC systems with dual treatment systems.

The other top two reasons for LVHC vents are due to either interlocks in the gas transport system or parameters on process equipment being outside of the normal range. If the facility upgrades or replaces the collection system, it is unlikely that the "improved" system could accept gases. In the case where gases cannot be introduced due to process equipment parameters being out of range, an "improved" collection system would probably not be able to accept the gases for the same reason.

Discussions amongst members have not developed potential solutions that will eliminate these types of non-SSM events.

Other prevalent reasons for LVHC/HVLC system vents include:

- Isolated venting of process equipment before reaching steady state,
- Inability to resolve interlocks due to process variability during start-up and shutdown,
- Intermittent venting of isolated sections of the transport system due to flow balancing issues,
- Purge requirement of concentrated NCG line before pulp mill start-up (to prevent air from entering LVHC system), and
- Transient venting of LVHC and HVLC sources due to slow "warm up" of boiler (low process steam requirements)

These events are caused due to variability of process equipment and again "improved" collection and back-up treatment systems will not eliminate the need for these events.

Steam Strippers

Under the existing MACT standards, for both steam strippers and stand-alone biological treatment systems that treat only condensates, periods of excess emissions are not violations provided that such periods do not exceed 10 percent of the total process operating time in a semi-annual reporting period. Currently 43 facilities have only steam strippers and at least one facility has a stand-alone biological treatment system to meet the compliance standards for pulp and paper condensates. In general, facilities do not have back-up systems for steam-strippers or biological treatment systems and facilities that use both devices generally need both systems to meet the treatment standard.

Stripper systems require maintenance, and when there are problems with their operation, the systems can require significant work to get them back to serviceable condition. Some common maintenance activities are listed below that can take anywhere from 4 hours to several days.

- Stripper Boilout/Clean-out of the Preheater and Trays;
- Acid Clean the Stripper Column
- Process Variation that Require Diversion of Condensates from Treatment Systems, and
- Equipment Failure for the Treatment System

If a stand –alone biological treatment system fails, it can take 15-18 days for the system to recover. For these systems it is not cost effective to install an additional treatment system and facilities would probably opt to install a back-up stripper if a back-up system was required.

As noted above, when condensates are not being directed to the steam stripper, they are typically still treated (although not to levels that would meet the treatment standards). While back-up devices could minimize the duration and number of events, the capital costs for these units is prohibitive especially considering that condensates are treated during these events.

Summary

As noted, the estimated costs to install these systems is $750 M, which is cost-prohibitive and unnecessary given that EPA has determined that the remaining health risks associated with the current rule, which included emissions during venting, are acceptable. Even with installation of redundant control systems and "improved" collection systems, mills would not be able to prevent all incidents of stripper downtime and/or gas collection and control system venting due to process variability, equipment maintenance, and safety concerns.

Attachment 8a

Attachment A to Cost Estimate, Excel File, Cost Estimate of Proposed Rules Changes to 40 CFR 63 Subpart S, Elimination of Excess Emission Allowances, June 2012

Cost Estimate of Proposed Rules Changes to 40 CFR 63 Subpart S
Elimination of Excess Emission Allowances

Current Treatment Options for Kraft Condensate Mills	Number of Units	Notes
Stripping	43	Based on ICR Collection Request Data published by EPA.
Biological Treatment	39	
Biological Treatment & Stripping	9	
Recycle	5	
Thermal Incinerator	1	
CCA	38	
CCA Mills that also collect a subset of HVLC gases	3	Based on information from NCASI.
Mills that have backup HVLC Control Devices	34	Based on NCASI Survey (28 of 80 mills that responded have backup control devices for HVLC). Extrapolated results for 97

Assumptions	Notes		Units
Cost to Route HVLC Systems to a Backup Control Device	1	$ 5,000,000	$
Costs to Upgrade existing HVLC/LVHC Collection Systems	2	$ 2,000,000	$
Costs to Replace existing HVLC/LVHC Collection Systems	3	$ 7,500,000	$
Costs to Install Back-up Steam Strippers	4	$ 7,400,000	$

	Notes	Number of Units Affected	Capital Cost
Cost to Route HVLC Systems to a Backup Control Device	5	28	$ 100,000,000
Costs to Upgrade existing HVLC/LVHC Collection Systems	6	73	$ 150,000,000
Costs to Replace existing HVLC/LVHC Collection Systems	6	24	$ 200,000,000
Costs to Install Back-up Steam Strippers	7	43	$ 300,000,000
TOTAL			**$ 750,000,000**

EPA did not include any information in the record describing how EPA expected mills to comply with the new standards. Therefore, AF&PA carefully examined what would be necessary to comply with the proposal. It should be noted that all cost estimates in these comments are based on the best information available. These are based on conservative estimates of upgrades and number of units affected and not detailed mill by mill engineering estimates. Even with these caveats, the estimates significantly higher than EPA's. AF&PA continues to make further refinements based on updated and increased information from member companies so these costs are different than those previously presented to the agency.

Notes

1. Assumes all units will need to have a backup incineration device and this device is available (i.e., no new incinerator, oxidizer, etc.). Cost estimate of $5 M/per facility is based on recent member costs to route HVLC gases to an existing Recovery Furnace. The cost to route to a boiler or other incinerator could be less, but the facility could trigger PSD for SO2 and therefore have additional costs and/or the need to update the controls on the incineration devices (costs not included in estimate).
2. Based on member input to upgrade HVLC/LVHC collection system (i.e., install redudant flame arrestors, overdesign condensers, etc.)
3. Based on member input to replace HVLC/LVHC collection systems ($ 5 - 10 MM/facility).
4. Stripper upgrade costs based on cost from a AF&PA member facility for an upgrade to a non-integrated stripper in 2010.
5. Costs exclude facilities that utilize CCA (except for three facilities that also collect HVLC gases) and facilities with backup HVLC systems
6. Assume that 25% of facilities will need to completely replace their HVLC/LVHC collection systems. The remainig 75% will only need to upgrade their gas collection systems.
7. Assume that facilities with strippers will need to install a backup control device. Systems with dual treatment (strippers and biological treatment systems) will not need backup strippers.

From: Craig, Jeneva
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CC: DeMocker, Jim
Sent: 6/25/2013 1:16:37 PM
Subject: President's Climate Action Plan
Attachments: June_25_13 President Climate Plan.pdf

Dear CAAAC Members,

For your information (and in the event you haven't already seen this document), I'm sending you the President's climate action plan that he will discuss at a speech today around 1:30.

Look forward to talking with you at our 3 pm teleconference.

Jenny Craig
Designated Federal Officer
Clean Air Act Advisory Committee
US EPA
Office of Air and Radiation
202-564-1674
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*** EMBARGOED FOR 6:00 AM EST TUESDAY, JUNE 25 ***

THE PRESIDENT'S CLIMATE ACTION PLAN

Executive Office of the President

June 2013

THE WHITE HOUSE
WASHINGTON

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PRESIDENT OBAMA'S CLIMATE ACTION PLAN

"We, the people, still believe that our obligations as Americans are not just to ourselves, but to all posterity. We will respond to the threat of climate change, knowing that the failure to do so would betray our children and future generations. Some may still deny the overwhelming judgment of science, but none can avoid the devastating impact of raging fires and crippling drought and more powerful storms.

The path towards sustainable energy sources will be long and sometimes difficult. But America cannot resist this transition, we must lead it. We cannot cede to other nations the technology that will power new jobs and new industries, we must claim its promise. That's how we will maintain our economic vitality and our national treasure -- our forests and waterways, our croplands and snow-capped peaks. That is how we will preserve our planet, commanded to our care by God. That's what will lend meaning to the creed our fathers once declared."

-- President Obama, Second Inaugural Address, January 2013

THE CASE FOR ACTION

While no single step can reverse the effects of climate change, we have a moral obligation to future generations to leave them a planet that is not polluted and damaged. Through steady, responsible action to cut carbon pollution, we can protect our children's health and begin to slow the effects of climate change so that we leave behind a cleaner, more stable environment.

In 2009, President Obama made a pledge that by 2020, America would reduce its greenhouse gas emissions in the range of 17 percent below 2005 levels if all other major economies agreed to limit their emissions as well. Today, the President remains firmly committed to that goal and to building on the progress of his first term to help put us and the world on a sustainable long-term trajectory. Thanks in part to the Administration's success in doubling America's use of wind, solar, and geothermal energy and in establishing the toughest fuel economy standards in our history, we are creating new jobs, building new industries, and reducing dangerous carbon pollution which contributes to climate change. In fact, last year, carbon emissions from the energy sector fell to the lowest level in two decades. At the same time, while there is more work to do, we are more energy secure than at any time in recent history. In 2012, America's net oil imports fell to the lowest level in 20 years and we have become the world's leading producer of natural gas – the cleanest-burning fossil fuel.

While this progress is encouraging, climate change is no longer a distant threat – we are already feeling its impacts across the country and the world. Last year was the warmest year ever in the contiguous United States and about one-third of all Americans experienced 10 days or more of 100-degree heat. The 12 hottest years on record have all come in the last 15 years. Asthma rates have doubled in the past 30 years and our children will suffer more asthma attacks as air pollution gets worse. And increasing floods, heat waves, and droughts have put farmers out of business, which is already raising food prices dramatically.

These changes come with far-reaching consequences and real economic costs. Last year alone, there were 11 different weather and climate disaster events with estimated losses exceeding $1 billion each across the United States. Taken together, these 11 events resulted in over $110 billion in estimated damages, which would make it the second-costliest year on record.

In short, America stands at a critical juncture. Today, President Obama is putting forward a broad-based plan to cut the carbon pollution that causes climate change and affects public health. Cutting carbon pollution will help spark business innovation to modernize our power plants, resulting in cleaner forms of American-made energy that will create good jobs and cut our dependence on foreign oil. Combined with the Administration's other actions to increase the efficiency of our cars and household appliances, the President's plan will reduce the amount of energy consumed by American families, cutting down on their gas and utility bills. The plan, which consists of a wide variety of executive actions, has three key pillars:

1) **Cut Carbon Pollution in America:** In 2012, U.S. carbon emissions fell to the lowest level in two decades even as the economy continued to grow. To build on this progress, the Obama Administration is putting in place tough new rules to cut carbon pollution – just like we have for other toxins like mercury and arsenic – so we protect the health of our children and move our economy toward American-made clean energy sources that will create good jobs and lower home energy bills.

2) **Prepare the United States for the Impacts of Climate Change:** Even as we take new steps to reduce carbon pollution, we must also prepare for the impacts of a changing climate that are already being felt across the country. Moving forward, the Obama Administration will help state and local governments strengthen our roads, bridges, and shorelines so we can better protect people's homes, businesses and way of life from severe weather.

3) **Lead International Efforts to Combat Global Climate Change and Prepare for its Impacts:** Just as no country is immune from the impacts of climate change, no country can meet this challenge alone. That is why it is imperative for the United States to couple action at home with leadership internationally. America must help forge a truly global solution to this global challenge by galvanizing international action to significantly reduce emissions (particularly among the major emitting countries), prepare for climate impacts, and drive progress through the international negotiations.

Climate change represents one of our greatest challenges of our time, but it is a challenge uniquely suited to America's strengths. Our scientists will design new fuels, and our farmers will grow them. Our engineers to devise new sources of energy, our workers will build them, and our businesses will sell them. All of us will need to do our part. If we embrace this challenge, we will not just create new jobs and new industries and keep America on the cutting edge; we will save lives, protect and preserve our treasured natural resources, cities, and coastlines for future generations.

What follows is a blueprint for steady, responsible national and international action to slow the effects of climate change so we leave a cleaner, more stable environment for future generations. It highlights progress already set in motion by the Obama Administration to advance these goals and sets forth new steps to achieve them.

CUT CARBON POLLUTION IN AMERICA

In 2009, President Obama made a commitment to reduce U.S. greenhouse gas emissions in the range of 17 percent below 2005 levels by 2020. The President remains firmly committed to achieving that goal. While there is more work to do, the Obama Administration has already made significant progress by doubling generation of electricity from wind, solar, and geothermal, and by establishing historic new fuel economy standards. Building on these achievements, this document outlines additional steps the Administration will take – in partnership with states, local communities, and the private sector – to continue on a path to meeting the President's 2020 goal.

I. Deploying Clean Energy

Cutting Carbon Pollution from Power Plants: Power plants are the largest concentrated source of emissions in the United States, together accounting for roughly one-third of all domestic greenhouse gas emissions. We have already set limits for arsenic, mercury, and lead, but there is no federal rule to prevent power plants from releasing as much carbon pollution as they want. Many states, local governments, and companies have taken steps to move to cleaner electricity sources. More than 35 states have renewable energy targets in place, and more than 25 have set energy efficiency targets.

Despite this progress at the state level, there are no federal standards in place to reduce carbon pollution from power plants. In April 2012, as part of a continued effort to modernize our electric power sector, the Obama Administration proposed a carbon pollution standard for new power plants. The Environmental Protection Agency's proposal reflects and reinforces the ongoing trend towards cleaner technologies, with natural gas increasing its share of electricity generation in recent years, principally through market forces and renewables deployment growing rapidly to account for roughly half of new generation capacity installed in 2012.

With abundant clean energy solutions available, and building on the leadership of states and local governments, we can make continued progress in reducing power plant pollution to improve public health and the environment while supplying the reliable, affordable power needed for economic growth. By doing so, we will continue to drive American leadership in clean energy technologies, such as efficient natural gas, nuclear, renewables, and clean coal technology.

To accomplish these goals, President Obama is issuing a Presidential Memorandum directing the Environmental Protection Agency to work expeditiously to complete carbon pollution standards for both new and existing power plants. This work will build on the successful first-term effort to develop greenhouse gas and fuel economy standards for cars and trucks. In developing the standards, the President has asked the Environmental Protection Agency to build on state leadership, provide flexibility, and take advantage of a wide range of energy sources and technologies including many actions in this plan.

Promoting American Leadership in Renewable Energy: During the President's first term, the United States more than doubled generation of electricity from wind, solar, and geothermal sources. To ensure America's continued leadership position in clean energy, President Obama has set a goal to double renewable electricity generation once again by 2020. In order to meet

this ambitious target, the Administration is announcing a number of new efforts in the following key areas:

- **Accelerating Clean Energy Permitting:** In 2012 the President set a goal to issue permits for 10 gigawatts of renewables on public lands by the end of the year. The Department of the Interior achieved this goal ahead of schedule and the President has directed it to permit an additional 10 gigawatts by 2020. Since 2009, the Department of Interior has approved 25 utility-scale solar facilities, nine wind farms, and 11 geothermal plants, which will provide enough electricity to power 4.4 million homes and support an estimated 17,000 jobs. The Administration is also taking steps to encourage the development of hydroelectric power at existing dams. To develop and demonstrate improved permitting procedures for such projects, the Administration will designate the Red Rock Hydroelectric Plant on the Des Moines River in Iowa to participate in its Infrastructure Permitting Dashboard for high-priority projects. Also, the Department of Defense – the single largest consumer of energy in the United States – is committed to deploying 3 gigawatts of renewable energy on military installations, including solar, wind, biomass, and geothermal, by 2025. In addition, federal agencies are setting a new goal of reaching 100 megawatts of installed renewable capacity across the federally subsidized housing stock by 2020. This effort will include conducting a survey of current projects in order to track progress and facilitate the sharing of best practices.

- **Expanding and Modernizing the Electric Grid:** Upgrading the country's electric grid is critical to our efforts to make electricity more reliable, save consumers money on their energy bills, and promote clean energy sources. To advance these important goals, President Obama signed a Presidential Memorandum this month that directs federal agencies to streamline the siting, permitting and review process for transmission projects across federal, state, and tribal governments.

Unlocking Long-Term Investment in Clean Energy Innovation: The Fiscal Year 2014 Budget continues the President's commitment to keeping the United States at the forefront of clean energy research, development, and deployment by increasing funding for clean energy technology across all agencies by 30 percent, to approximately $7.9 billion. This includes investment in a range of energy technologies, from advanced biofuels and emerging nuclear technologies – including small modular reactors – to clean coal. To continue America's leadership in clean energy innovation, the Administration will also take the following steps:

- **Spurring Investment in Advanced Fossil Energy Projects:** In the coming weeks, the Department of Energy will issue a Federal Register Notice announcing a draft of a solicitation that would make up to $8 billion in (self-pay) loan guarantee authority available for a wide array of advanced fossil energy projects under its Section 1703 loan guarantee program. This solicitation is designed to support investments in innovative technologies that can cost-effectively meet financial and policy goals, including the avoidance, reduction, or sequestration of anthropogenic emissions of greenhouse gases. The proposed solicitation will cover a broad range of advanced fossil energy projects. Reflecting the Department's commitment to continuous improvement in program management, it will take comment on the draft solicitation, with a plan to issue a final solicitation by the fall of 2013.

- **Instituting a Federal Quadrennial Energy Review:** Innovation and new sources of domestic energy supply are transforming the nation's energy marketplace, creating economic

opportunities at the same time they raise environmental challenges. To ensure that federal energy policy meets our economic, environmental, and security goals in this changing landscape, the Administration will conduct a Quadrennial Energy Review which will be led by the White House Domestic Policy Council and Office of Science and Technology Policy, supported by a Secretariat established at the Department of Energy, and involving the robust engagement of federal agencies and outside stakeholders. This first-ever review will focus on infrastructure challenges, and will identify the threats, risks, and opportunities for U.S. energy and climate security, enabling the federal government to translate policy goals into a set of analytically based, clearly articulated, sequenced and integrated actions, and proposed investments over a four-year planning horizon.

II. Building a 21st-Century Transportation Sector

Increasing Fuel Economy Standards: Heavy-duty vehicles are currently the second largest source of greenhouse gas emissions within the transportation sector. In 2011, the Obama Administration finalized the first-ever fuel economy standards for Model Year 2014-2018 for heavy-duty trucks, buses, and vans. These standards will reduce greenhouse gas emissions by approximately 270 million metric tons and save 530 million barrels of oil. During the President's second term, the Administration will once again partner with industry leaders and other key stakeholders to develop post-2018 fuel economy standards for heavy-duty vehicles to further reduce fuel consumption through the application of advanced cost-effective technologies and continue efforts to improve the efficiency of moving goods across the United States.

The Obama Administration has already established the toughest fuel economy standards for passenger vehicles in U.S. history. These standards require an average performance equivalent of 54.5 miles per gallon by 2025, which will save the average driver more than $8,000 in fuel costs over the lifetime of the vehicle and eliminate six billion metric tons of carbon pollution – more than the United States emits in an entire year.

Developing and Deploying Advanced Transportation Technologies: Biofuels have an important role to play in increasing our energy security, fostering rural economic development, and reducing greenhouse gas emissions from the transportation sector. That is why the Administration supports the Renewable Fuels Standard, and is investing in research and development to help bring next-generation biofuels on line. For example, the United States Navy and Departments of Energy and Agriculture are working with the private sector to accelerate the development of cost-competitive advanced biofuels for use by the military and commercial sectors. More broadly, the Administration will continue to leverage partnerships between the private and public sectors to deploy cleaner fuels, including advanced batteries and fuel cell technologies, in every transportation mode. The Department of Energy's eGallon informs drivers about electric car operating costs in their state – the national average is only $1.14 per gallon of gasoline equivalent, showing the promise for consumer pocketbooks of electric-powered vehicles. In addition, in the coming months, the Department of Transportation will work with other agencies to further explore strategies for integrating alternative fuel vessels into the U.S. flag fleet. Further, the Administration will continue to work with states, cities and towns through the Department of Transportation, the Department of Housing and Urban Development, and the Environmental Protection Agency to improve transportation options, and lower transportation costs while protecting the environment in communities nationwide.

III. Cutting Energy Waste in Homes, Businesses, and Factories

Reducing Energy Bills for American Families and Businesses: Energy efficiency is one of the clearest and most cost-effective opportunities to save families money, make our businesses more competitive, and reduce greenhouse gas emissions. In the President's first term, the Department of Energy and the Department of Housing and Urban Development completed efficiency upgrades in more than one million homes, saving many families more than $400 on their heating and cooling bills in the first year alone. The Administration will take a range of new steps geared towards achieving President Obama's goal of doubling energy productivity by 2030 relative to 2010 levels:

- **Establishing a New Goal for Energy Efficiency Standards:** In President Obama's first term, the Department of Energy established new minimum efficiency standards for dishwashers, refrigerators, and many other products. Through 2030, these standards will cut consumers' electricity bills by hundreds of billions of dollars and save enough electricity to power more than 85 million homes for two years. To build on this success, the Administration is setting a new goal: Efficiency standards for appliances and federal buildings set in the first and second terms combined will reduce carbon pollution by at least 3 billion metric tons cumulatively by 2030 – equivalent to nearly one-half of the carbon pollution from the entire U.S. energy sector for one year – while continuing to cut families' energy bills.

- **Reducing Barriers to Investment in Energy Efficiency:** Energy efficiency upgrades bring significant cost savings, but upfront costs act as a barrier to more widespread investment. In response, the Administration is committing to a number of new executive actions. As soon as this fall, the Department of Agriculture's Rural Utilities Service will finalize a proposed update to its Energy Efficiency and Conservation Loan Program to provide up to $250 million for rural utilities to finance efficiency investments by businesses and homeowners across rural America. The Department is also streamlining its Rural Energy for America program to provide grants and loan guarantees directly to agricultural producers and rural small businesses for energy efficiency and renewable energy systems.

  In addition, the Department of Housing and Urban Development's efforts include a $23 million Multifamily Energy Innovation Fund designed to enable affordable housing providers, technology firms, academic institutions, and philanthropic organizations to test new approaches to deliver cost-effective residential energy. In order to advance ongoing efforts and bring stakeholders together, the Federal Housing Administration will convene representatives of the lending community and other key stakeholders for a mortgage roundtable in July to identify options for factoring energy efficiency into the mortgage underwriting and appraisal process upon sale or refinancing of new or existing homes.

- **Expanding the President's Better Buildings Challenge:** The Better Buildings Challenge, focused on helping American commercial and industrial buildings become at least 20 percent more energy efficient by 2020, is already showing results. More than 120 diverse organizations, representing over 2 billion square feet are on track to meet the 2020 goal: cutting energy use by an average 2.5 percent annually, equivalent to about $58 million in energy savings per year. To continue this success, the Administration will expand the program to multifamily housing – partnering both with private and affordable

building owners and public housing agencies to cut energy waste. In addition, the Administration is launching the Better Buildings Accelerators, a new track that will support and encourage adoption of State and local policies to cut energy waste, building on the momentum of ongoing efforts at that level.

IV. Reducing Other Greenhouse Gas Emissions

Curbing Emissions of Hydrofluorocarbons: Hydrofluorocarbons (HFCs), which are primarily used for refrigeration and air conditioning, are potent greenhouse gases. In the United States, emissions of HFCs are expected to nearly triple by 2030, and double from current levels of 1.5 percent of greenhouse gas emissions to 3 percent by 2020.

To reduce emissions of HFCs, the United States can and will lead both through international diplomacy as well as domestic actions. In fact, the Administration has already acted by including a flexible and powerful incentive in the fuel economy and carbon pollution standards for cars and trucks to encourage automakers to reduce HFC leakage and transition away from the most potent HFCs in vehicle air conditioning systems. Moving forward, the Environmental Protection Agency will use its authority through the Significant New Alternatives Policy Program to encourage private sector investment in low-emissions technology by identifying and approving climate-friendly chemicals while prohibiting certain uses of the most harmful chemical alternatives. In addition, the President has directed his Administration to purchase cleaner alternatives to HFCs whenever feasible and transition over time to equipment that uses safer and more sustainable alternatives.

Reducing Methane Emissions: Curbing emissions of methane is critical to our overall effort to address global climate change. Methane currently accounts for roughly 9 percent of domestic greenhouse gas emissions and has a global warming potential that is more than 20 times greater than carbon dioxide. Notably, since 1990, methane emissions in the United States have decreased by 8 percent. This has occurred in part through partnerships with industry, both at home and abroad, in which we have demonstrated that we have the technology to deliver emissions reductions that benefit both our economy and the environment. To achieve additional progress, the Administration will:

- **Developing an Interagency Methane Strategy:** The Environmental Protection Agency and the Departments of Agriculture, Energy, Interior, Labor, and Transportation will develop a comprehensive, interagency methane strategy. The group will focus on assessing current emissions data, addressing data gaps, identifying technologies and best practices for reducing emissions, and identifying existing authorities and incentive-based opportunities to reduce methane emissions.

- **Pursuing a Collaborative Approach to Reducing Emissions:** Across the economy, there are multiple sectors in which methane emissions can be reduced, from coal mines and landfills to agriculture and oil and gas development. For example, in the agricultural sector, over the last three years, the Environmental Protection Agency and the Department of Agriculture have worked with the dairy industry to increase the adoption of methane digesters through loans, incentives, and other assistance. In addition, when it comes to the oil and gas sector, investments to build and upgrade gas pipelines will not only put more Americans to work, but also reduce emissions and enhance economic productivity. For example, as part of the Administration's effort to improve federal

permitting for infrastructure projects, the interagency Bakken Federal Executive Group is working with industry, as well as state and tribal agencies, to advance the production of oil and gas in the Bakken while helping to reduce venting and flaring. Moving forward, as part of the effort to develop an interagency methane strategy, the Obama Administration will work collaboratively with state governments, as well as the private sector, to reduce emissions across multiple sectors, improve air quality, and achieve public health and economic benefits.

Preserving the Role of Forests in Mitigating Climate Change: America's forests play a critical role in addressing carbon pollution, removing nearly 12 percent of total U.S. greenhouse gas emissions each year. In the face of a changing climate and increased risk of wildfire, drought, and pests, the capacity of our forests to absorb carbon is diminishing. Pressures to develop forest lands for urban or agricultural uses also contribute to the decline of forest carbon sequestration. Conservation and sustainable management can help to ensure our forests continue to remove carbon from the atmosphere while also improving soil and water quality, reducing wildfire risk, and otherwise managing forests to be more resilient in the fact of climate change. The Administration is working to identify new approaches to protect and restore our forests, as well as other critical landscapes including grasslands and wetlands, in the face of a changing climate.

V. Leading at the Federal Level

Leading in Clean Energy: President Obama believes that the federal government must be a leader in clean energy and energy efficiency. Under the Obama Administration, federal agencies have reduced greenhouse gas emissions by more than 15 percent – the equivalent of permanently taking 1.5 million cars off the road. To build on this record, the Administration is establishing a new goal: The federal government will consume 20 percent of its electricity from renewable sources by 2020 – more than double the current goal of 7.5 percent. In addition, the federal government will continue to pursue greater energy efficiency that reduces greenhouse gas emissions and saves taxpayer dollars.

Federal Government Leadership in Energy Efficiency: On December 2, 2011, President Obama signed a memorandum entitled "Implementation of Energy Savings Projects and Performance-Based Contracting for Energy Savings," challenging federal agencies, in support of the Better Buildings Challenge, to enter into $2 billion worth of performance-based contracts within two years. Performance contracts drive economic development, utilize private sector innovation, and increase efficiency at minimum costs to the taxpayer, while also providing long-term savings in energy costs. Federal agencies have committed to a pipeline of nearly $2.3 billion from over 300 reported projects. In coming months, the Administration will take a number of actions to strengthen efforts to promote energy efficiency, including through performance contracting. For example, in order to increase access to capital markets for investments in energy efficiency, the Administration will initiate a partnership with the private sector to work towards a standardized contract to finance federal investments in energy efficiency. Going forward, agencies will also work together to synchronize building codes – leveraging those policies to improve the efficiency of federally owned and supported building stock. Finally, the Administration will leverage the "Green Button" standard – which aggregates energy data in a secure, easy to use format – within federal facilities to increase their ability to manage energy consumption, reduce greenhouse gas emissions, and meet sustainability goals.

PREPARE THE UNITED STATES FOR THE IMPACTS OF CLIMATE CHANGE

As we act to curb the greenhouse gas pollution that is driving climate change, we must also prepare for the impacts that are too late to avoid. Across America, states, cities, and communities are taking steps to protect themselves by updating building codes, adjusting the way they manage natural resources, investing in more resilient infrastructure, and planning for rapid recovery from damages that nonetheless occur. The federal government has an important role to play in supporting community-based preparedness and resilience efforts, establishing policies that promote preparedness, protecting critical infrastructure and public resources, supporting science and research germane to preparedness and resilience, and ensuring that federal operations and facilities continue to protect and serve citizens in a changing climate.

The Obama Administration has been working to strengthen America's climate resilience since its earliest days. Shortly after coming into office, President Obama established an Interagency Climate Change Adaptation Task Force and, in October 2009, the President signed an Executive Order directing it to recommend ways federal policies and programs can better prepare the Nation for change. In May 2010, the Task Force hosted the first National Climate Adaptation Summit, convening local and regional stakeholders and decision-makers to identify challenges and opportunities for collaborative action.

In February 2013, federal agencies released Climate Change Adaptation Plans for the first time, outlining strategies to protect their operations, missions, and programs from the effects of climate change. The Department of Transportation, for example, is developing guidance for incorporating climate change and extreme weather event considerations into coastal highway projects, and the Department of Homeland Security is evaluating the challenges of changing conditions in the Arctic and along our Nation's borders. Agencies have also partnered with communities through targeted grant and technical-assistance programs—for example, the Environmental Protection Agency is working with low-lying communities in North Carolina to assess the vulnerability of infrastructure investments to sea level rise and identify solutions to reduce risks. And the Administration has continued, through the U.S. Global Change Research Program, to support science and monitoring to expand our understanding of climate change and its impacts.

Going forward, the Administration will expand these efforts into three major, interrelated initiatives to better prepare America for the impacts of climate change:

I. Building Stronger and Safer Communities and Infrastructure

By necessity, many states, cities, and communities are already planning and preparing for the impacts of climate change. Hospitals must build capacity to serve patients during more frequent heat waves, and urban planners must plan for the severe storms that infrastructure will need to withstand. Promoting on-the-ground planning and resilient infrastructure will be at the core of our work to strengthen America's communities. Specific actions will include:

Directing Agencies to Support Climate-Resilient Investment: The President will direct federal agencies to identify and remove barriers to making climate-resilient investments; identify and remove counterproductive policies that increase vulnerabilities; and encourage and support smarter, more resilient investments, including through agency grants, technical assistance, and other programs, in sectors from transportation and water management to conservation and

disaster relief. Agencies will also be directed to ensure that climate risk-management considerations are fully integrated into federal infrastructure and natural resource management planning. To begin meeting this challenge, the Environmental Protection Agency is committing to integrate considerations of climate change impacts and adaptive measures into major programs, including its Clean Water and Drinking Water State Revolving Funds and grants for brownfields cleanup, and the Department of Housing and Urban Development is already requiring grant recipients in the Hurricane Sandy–affected region to take sea-level rise into account.

Establishing a State, Local, and Tribal Leaders Task Force on Climate Preparedness: To help agencies meet the above directive and to enhance local efforts to protect communities, the President will establish a short-term task force of state, local, and tribal officials to advise on key actions the federal government can take to better support local preparedness and resilience-building efforts. The task force will provide recommendations on removing barriers to resilient investments, modernizing grant and loan programs to better support local efforts, and developing information and tools to better serve communities.

Supporting Communities as they Prepare for Climate Impacts: Federal agencies will continue to provide targeted support and assistance to help communities prepare for climate-change impacts. For example, throughout 2013, the Department of Transportation's Federal Highway Administration is working with 19 state and regional partners and other federal agencies to test approaches for assessing local transportation infrastructure vulnerability to climate change and extreme weather and for improving resilience. The Administration will continue to assist tribal communities on preparedness through the Bureau of Indian Affairs, including through pilot projects and by supporting participation in federal initiatives that assess climate change vulnerabilities and develop regional solutions. Through annual federal agency "Environmental Justice Progress Reports," the Administration will continue to identify innovative ways to help our most vulnerable communities prepare for and recover from the impacts of climate change. The importance of critical infrastructure independence was brought home in the Sandy response. The Federal Emergency Management Agency and the Department of Energy are working with the private sector to address simultaneous restoration of electricity and fuels supply.

Boosting the Resilience of Buildings and Infrastructure: The National Institute of Standards and Technology will convene a panel on disaster-resilience standards to develop a comprehensive, community-based resilience framework and provide guidelines for consistently safe buildings and infrastructure – products that can inform the development of private-sector standards and codes. In addition, building on federal agencies' "Climate Change Adaptation Plans," the Administration will continue efforts to increase the resilience of federal facilities and infrastructure. The Department of Defense, for example, is assessing the relative vulnerability of its coastal facilities to climate change. In addition, the President's FY 2014 Budget proposes $200 million through the Transportation Leadership Awards program for Climate Ready Infrastructure in communities that build enhanced preparedness into their planning efforts, and that have proposed or are ready to break ground on infrastructure projects, including transit and rail, to improve resilience.

Rebuilding and Learning from Hurricane Sandy: In August 2013, President Obama's Hurricane Sandy Rebuilding Task Force will deliver to the President a rebuilding strategy to be implemented in Sandy-affected regions and establishing precedents that can be followed

elsewhere. The Task Force and federal agencies are also piloting new ways to support resilience in the Sandy-affected region; the Task Force, for example, is hosting a regional "Rebuilding by Design" competition to generate innovative solutions to enhance resilience. In the transportation sector, the Department of Transportation's Federal Transit Administration (FTA) is dedicating $5.7 billion to four of the area's most impacted transit agencies, of which $1.3 billion will be allocated to locally prioritized projects to make transit systems more resilient to future disasters. FTA will also develop a competitive process for additional funding to identify and support larger, stand-alone resilience projects in the impacted region. To build coastal resilience, the Department of the Interior will launch a $100 million competitive grant program to foster partnerships and promote resilient natural systems while enhancing green spaces and wildlife habitat near urban populations. An additional $250 million will be allocated to support projects for coastal restoration and resilience across the region. Finally, with partners, the U.S. Army Corps of Engineers is conducting a $20 million study to identify strategies to reduce the vulnerability of Sandy-affected coastal communities to future large-scale flood and storm events, and the National Oceanic and Atmospheric Administration will strengthen long-term coastal observations and provide technical assistance to coastal communities.

II. Protecting our Economy and Natural Resources

Climate change is affecting nearly every aspect of our society, from agriculture and tourism to the health and safety of our citizens and natural resources. To help protect critical sectors, while also targeting hazards that cut across sectors and regions, the Administration will mount a set of sector- and hazard-specific efforts to protect our country's vital assets, to include:

Identifying Vulnerabilities of Key Sectors to Climate Change: The Department of Energy will soon release an assessment of climate-change impacts on the energy sector, including power-plant disruptions due to drought and the disruption of fuel supplies during severe storms, as well as potential opportunities to make our energy infrastructure more resilient to these risks. In 2013, the Department of Agriculture and Department of the Interior released several studies outlining the challenges a changing climate poses for America's agricultural enterprise, forests, water supply, wildlife, and public lands. This year and next, federal agencies will report on the impacts of climate change on other key sectors and strategies to address them, with priority efforts focusing on health, transportation, food supplies, oceans, and coastal communities.

Promoting Resilience in the Health Sector: The Department of Health and Human Services will launch an effort to create sustainable and resilient hospitals in the face of climate change. Through a public-private partnership with the healthcare industry, it will identify best practices and provide guidance on affordable measures to ensure that our medical system is resilient to climate impacts. It will also collaborate with partner agencies to share best practices among federal health facilities. And, building on lessons from pilot projects underway in 16 states, it will help train public-health professionals and community leaders to prepare their communities for the health consequences of climate change, including through effective communication of health risks and resilience measures.

Promoting Insurance Leadership for Climate Safety: Recognizing the critical role that the private sector plays in insuring assets and enabling rapid recovery after disasters, the Administration will convene representatives from the insurance industry and other stakeholders to explore best practices for private and public insurers to manage their own processes and

investments to account for climate change risks and incentivize policy holders to take steps to reduce their exposure to these risks.

Conserving Land and Water Resources: America's ecosystems are critical to our nation's economy and the lives and health of our citizens. These natural resources can also help ameliorate the impacts of climate change, if they are properly protected. The Administration has invested significantly in conserving relevant ecosystems, including working with Gulf State partners after the Deepwater Horizon spill to enhance barrier islands and marshes that protect communities from severe storms. The Administration is also implementing climate-adaptation strategies that promote resilience in fish and wildlife populations, forests and other plant communities, freshwater resources, and the ocean. Building on these efforts, the President is also directing federal agencies to identify and evaluate additional approaches to improve our natural defenses against extreme weather, protect biodiversity and conserve natural resources in the face of a changing climate, and manage our public lands and natural systems to store more carbon.

Maintaining Agricultural Sustainability: Building on the existing network of federal climate-science research and action centers, the Department of Agriculture is creating seven new Regional Climate Hubs to deliver tailored, science-based knowledge to farmers, ranchers, and forest landowners. These hubs will work with universities and other partners, including the Department of the Interior and the National Oceanic and Atmospheric Administration, to support climate resilience. Its Natural Resources Conservation Service and the Department of the Interior's Bureau of Reclamation are also providing grants and technical support to agricultural water users for more water-efficient practices in the face of drought and long-term climate change.

Managing Drought: Leveraging the work of the National Disaster Recovery Framework for drought, the Administration will launch a cross-agency National Drought Resilience Partnership as a "front door" for communities seeking help to prepare for future droughts and reduce drought impacts. By linking information (monitoring, forecasts, outlooks, and early warnings) with drought preparedness and longer-term resilience strategies in critical sectors, this effort will help communities manage drought-related risks.

Reducing Wildfire Risks: With tribes, states, and local governments as partners, the Administration has worked to make landscapes more resistant to wildfires, which are exacerbated by heat and drought conditions resulting from climate change. Federal agencies will expand and prioritize forest and rangeland restoration efforts in order to make natural areas and communities less vulnerable to catastrophic fire. The Department of the Interior and Department of Agriculture, for example, are launching a Western Watershed Enhancement Partnership – a pilot effort in five western states to reduce wildfire risk by removing extra brush and other flammable vegetation around critical areas such as water reservoirs.

Preparing for Future Floods: To ensure that projects funded with taxpayer dollars last as long as intended, federal agencies will update their flood-risk reduction standards for federally funded projects to reflect a consistent approach that accounts for sea-level rise and other factors affecting flood risks. This effort will incorporate the most recent science on expected rates of sea-level rise (which vary by region) and build on work done by the Hurricane Sandy Rebuilding Task Force, which announced in April 2013 that all federally funded Sandy-related rebuilding projects must meet a consistent flood risk reduction standard that takes into account increased risk from extreme weather events, sea-level rise, and other impacts of climate change.

III. Using Sound Science to Manage Climate Impacts

Scientific data and insights are essential to help government officials, communities, and businesses better understand and manage the risks associated with climate change. The Administration will continue to lead in advancing the science of climate measurement and adaptation and the development of tools for climate-relevant decision-making by focusing on increasing the availability, accessibility, and utility of relevant scientific tools and information. Specific actions will include:

Developing Actionable Climate Science: The President's Fiscal Year 2014 Budget provides more than $2.7 billion, largely through the 13-agency U.S. Global Change Research Program, to increase understanding of climate-change impacts, establish a public-private partnership to explore risk and catastrophe modeling, and develop the information and tools needed by decision-makers to respond to both long-term climate change impacts and near-term effects of extreme weather.

Assessing Climate-Change Impacts in the United States: In the spring of 2014, the Obama Administration will release the third U.S. National Climate Assessment, highlighting new advances in our understanding of climate-change impacts across all regions of the United States and on critical sectors of the economy, including transportation, energy, agriculture, and ecosystems and biodiversity. For the first time, the National Climate Assessment will focus not only on dissemination of scientific information but also on translating scientific insights into practical, useable knowledge that can help decision-makers anticipate and prepare for specific climate-change impacts.

Launching a Climate Data Initiative: Consistent with the President's May 2013 Executive Order on Open Data – and recognizing that freely available open government data can fuel entrepreneurship, innovation, scientific discovery, and public benefits – the Administration is launching a Climate Data Initiative to leverage extensive federal climate-relevant data to stimulate innovation and private-sector entrepreneurship in support of national climate-change preparedness.

Providing a Toolkit for Climate Resilience: Federal agencies will create a virtual climate-resilience toolkit that centralizes access to data-driven resilience tools, services, and best practices, including those developed through the Climate Data Initiative. The toolkit will provide easy access to existing resources as well as new tools, including: interactive sea-level rise maps and a sea-level-rise calculator to aid post-Sandy rebuilding in New York and New Jersey, new NOAA storm surge models and interactive maps from the National Oceanic and Atmospheric Administration that provide risk information by combining tidal data, projected sea levels and storm wave heights, a web-based tool that will allow developers to integrate NASA climate imagery into websites and mobile apps, access to the U.S. Geological Survey's "visualization tool" to assess the amount of carbon absorbed by landscapes, and a Stormwater Calculator and Climate Assessment Tool developed to help local governments assess stormwater-control measures under different precipitation and temperature scenarios.

LEAD INTERNATIONAL EFFORTS TO ADDRESS GLOBAL CLIMATE CHANGE

The Obama Administration is working to build on the actions that it is taking domestically to achieve significant global greenhouse gas emission reductions and enhance climate preparedness through major international initiatives focused on spurring concrete action, including bilateral initiatives with China, India, and other major emitting countries. These initiatives not only serve to support the efforts of the United States and others to achieve our goals for 2020, but also will help us move beyond those and bend the post-2020 global emissions trajectory further. As a key part of this effort, we are also working intensively to forge global responses to climate change through a number of important international negotiations, including the United Nations Framework Convention on Climate Change.

I. Working with Other Countries to Take Action to Address Climate Change

Enhancing Multilateral Engagement with Major Economies: In 2009, President Obama launched the Major Economies Forum on Energy and Climate, a high-level forum that brings together 17 countries that account for approximately 75 percent of global greenhouse gas emissions, in order to support the international climate negotiations and spur cooperative action to combat climate change. The Forum has been successful on both fronts – having contributed significantly to progress in the broader negotiations while also launching the Clean Energy Ministerial to catalyze the development and deployment of clean energy and efficiency solutions. We are proposing that the Forum build on these efforts by launching a major initiative this year focused on further accelerating efficiency gains in the buildings sector, which accounts for approximately one-third of global carbon pollutions from the energy sector.

Expanding Bilateral Cooperation with Major Emerging Economies:
From the outset, the Obama Administration has sought to intensify bilateral climate cooperation with key major emerging economies, through initiatives like the U.S.-China Clean Energy Research Center, the U.S.-India Partnership to Advance Clean Energy, and the Strategic Energy Dialogue with Brazil.

We will be building on these successes and finding new areas for cooperation in the second term, and we are already making progress: Just this month, President Obama and President Xi Jinping of China reached an historic agreement at their first summit to work to use the expertise and institutions of the Montreal Protocol to phase down the consumption and production of HFCs, a highly potent greenhouse gas. The impact of phasing out HFCs by 2050 would be equivalent to the elimination of two years' worth of greenhouse gas emissions from all sources.

Combatting Short-Lived Climate Pollutants: Pollutants such as methane, black carbon, and many HFCs are relatively short-lived in the atmosphere, but have more potent greenhouse effects than carbon dioxide. In February 2012, the United States launched the Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollution, which has grown to include more than 30 country partners and other key partners such as the World Bank and the U.N. Environment Programme. Major efforts include reducing methane and black carbon from waste and landfills. We are also leading through the Global Methane Initiative, which works with 42 partner countries and an extensive network of over 1,100 private sector participants to reduce methane emissions.

Reducing Emissions from Deforestation and Forest Degradation: Greenhouse gas emissions from deforestation, agriculture, and other land use constitute approximately one-third of global emissions. In some developing countries, as much as 80 percent of these emissions come from the land sector. To meet this challenge, the Obama Administration is working with partner countries to put in place the systems and institutions necessary to significantly reduce global land-use-related emissions, creating new models for rural development that generate climate benefits, while conserving biodiversity, protecting watersheds, and improving livelihoods.

In 2012 alone, the U.S. Agency for International Development's bilateral and regional forestry programs contributed to reducing more than 140 million tons of carbon dioxide emissions, including through support for multilateral initiatives such as the Forest Investment Program and the Forest Carbon Partnership Facility. In Indonesia, the Millennium Challenge Corporation is funding a five-year "Green Prosperity" program that supports environmentally sustainable, low carbon economic development in select districts.

The Obama Administration is also working to address agriculture-driven deforestation through initiatives such as the Tropical Forest Alliance 2020, which brings together governments, the private sector, and civil society to reduce tropical deforestation related to key agricultural commodities, which we will build upon.

Expanding Clean Energy Use and Cut Energy Waste: Roughly 84 percent of current carbon dioxide emissions are energy-related and about 65 percent of all greenhouse gas emissions can be attributed to energy supply and energy use. The Obama Administration has promoted the expansion of renewable, clean, and efficient energy sources and technologies worldwide through:

- Financing and regulatory support for renewable and clean energy projects
- Actions to promote fuel switching from oil and coal to natural gas or renewables
- Support for the safe and secure use of nuclear power
- Cooperation on clean coal technologies
- Programs to improve and disseminate energy efficient technologies

In the past three years we have reached agreements with more than 20 countries around the world, including Mexico, South Africa, and Indonesia, to support low emission development strategies that help countries to identify the best ways to reduce greenhouse gas emissions while growing their economies. Among the many initiatives that we have launched are:

- The U.S. Africa Clean Energy Finance Initiative, which aligns grant-based assistance with project planning expertise from the U.S. Trade and Development Agency and financing and risk mitigation tools from the U.S. Overseas Private Investment Corporation to unlock up to $1 billion in clean energy financing.

- The U.S.-Asia Pacific Comprehensive Energy Partnership, which has identified $6 billion in U.S. export credit and government financing to promote clean energy development in the Asia-Pacific region.

Looking ahead, we will target these and other resources towards greater penetration of renewables in the global energy mix on both a small and large scale, including through our

participation in the Sustainable Energy for All Initiative and accelerating the commercialization of renewable mini-grids. These efforts include:

- **Natural Gas.** Burning natural gas is about one-half as carbon-intensive as coal, which can make it a critical "bridge fuel" for many countries as the world transitions to even cleaner sources of energy. Toward that end, the Obama Administration is partnering with states and private companies to exchange lessons learned with our international partners on responsible development of natural gas resources. We have launched the Unconventional Gas Technical Engagement Program to share best practices on issues such as water management, methane emissions, air quality, permitting, contracting, and pricing to help increase global gas supplies and facilitate development of the associated infrastructure that brings them to market. Going forward, we will promote fuel-switching from coal to gas for electricity production and encourage the development of a global market for gas. Since heavy-duty vehicles are expected to account for 40 percent of increased oil use through 2030, we will encourage the adoption of heavy duty natural gas vehicles as well.

- **Nuclear Power.** The United States will continue to promote the safe and secure use of nuclear power worldwide through a variety of bilateral and multilateral engagements. For example, the U.S. Nuclear Regulatory Commission advises international partners on safety and regulatory best practices, and the Department of Energy works with international partners on research and development, nuclear waste and storage, training, regulations, quality control, and comprehensive fuel leasing options. Going forward, we will expand these efforts to promote nuclear energy generation consistent with maximizing safety and nonproliferation goals.

- **Clean Coal.** The United States works with China, India, and other countries that currently rely heavily on coal for power generation to advance the development and deployment of clean coal technologies. In addition, the U.S. leads the Carbon Sequestration Leadership Forum, which engages 23 other countries and economies on carbon capture and sequestration technologies. Going forward, we will continue to use these bilateral and multilateral efforts to promote clean coal technologies.

- **Energy Efficiency.** The Obama Administration has aggressively promoted energy efficiency through the Clean Energy Ministerial and key bilateral programs. The cost-effective opportunities are enormous: The Ministerial' s Super-Efficient Equipment and Appliance Deployment Initiative and its Global Superior Energy Performance Partnership are helping to accelerate the global adoption of standards and practices that would cut energy waste equivalent to more than 650 mid-size power plants by 2030. We will work to expand these efforts focusing on several critical areas, including: improving building efficiency, reducing energy consumption at water and wastewater treatment facilities, and expanding global appliance standards.

Negotiating Global Free Trade in Environmental Goods and Services: The U.S. will work with trading partners to launch negotiations at the World Trade Organization towards global free trade in environmental goods, including clean energy technologies such as solar, wind, hydro and geothermal. The U.S. will build on the consensus it recently forged among the 21 Asia-Pacific Economic Cooperation (APEC) economies in this area. In 2011, APEC economies agreed to reduce tariffs to 5 percent or less by 2015 on a negotiated list of 54 environmental goods. The

APEC list will serve as a foundation for a global agreement in the WTO, with participating countries expanding the scope by adding products of interest. Over the next year, we will work towards securing participation of countries which account for 90 percent of global trade in environmental goods, representing roughly $481 billion in annual environmental goods trade. We will also work in the Trade in Services Agreement negotiations towards achieving free trade in environmental services.

Phasing Out Subsidies that Encourage Wasteful Consumption of Fossil Fuels: The International Energy Agency estimates that the phase-out of fossil fuel subsidies – which amount to more than $500 billion annually – would lead to a 10 percent reduction in greenhouse gas emissions below business as usual by 2050. At the 2009 G-20 meeting in Pittsburgh, the United States successfully advocated for a commitment to phase out these subsidies, and we have since won similar commitments in other fora such as APEC. President Obama is calling for the elimination of U.S. fossil fuel tax subsidies in his Fiscal Year (FY) 2014 budget, and we will continue to collaborate with partners around the world toward this goal.

Leading Global Sector Public Financing Towards Cleaner Energy: Under this Administration, the United States has successfully mobilized billions of dollars for clean energy investments in developing countries, helping to accelerate their transition to a green, low-carbon economy. Building on these successes, the President calls for an end to U.S. government support for public financing of new coal plants overseas, except for (a) the most efficient coal technology available in the world's poorest countries in cases where no other economically feasible alternative exists, or (b) facilities deploying carbon capture and sequestration technologies. As part of this new commitment, we will work actively to secure the agreement of other countries and the multilateral development banks to adopt similar policies as soon as possible.

Strengthening Global Resilience to Climate Change: Failing to prepare adequately for the impacts of climate change that can no longer be avoided will put millions of people at risk, jeopardizing important development gains, and increasing the security risks that stem from climate change. That is why the Obama Administration has made historic investments in bolstering the capacity of countries to respond to climate-change risks. Going forward, we will continue to:

- Strengthen government and local community planning and response capacities, such as by increasing water storage and water use efficiency to cope with the increased variability in water supply

- Develop innovative financial risk management tools such as index insurance to help smallholder farmers and pastoralists manage risk associated with changing rainfall patterns and drought

- Distribute drought-resistant seeds and promote management practices that increase farmers' ability to cope with climate impacts.

Mobilizing Climate Finance: International climate finance is an important tool in our efforts to promote low-emissions, climate-resilient development. We have fulfilled our joint developed country commitment from the Copenhagen Accord to provide approximately $30 billion of climate assistance to developing countries over FY 2010-FY 2012. The United States contributed approximately $7.5 billion to this effort over the three year period. Going forward, we will seek

to build on this progress as well as focus our efforts on combining our public resources with smart policies to mobilize much larger flows of private investment in low-emissions and climate resilient infrastructure.

II. Leading Efforts to Address Climate Change through International Negotiations

The United States has made historic progress in the international climate negotiations during the past four years. At the Copenhagen Conference of the United Nations Framework Convention on Climate Change (UNFCCC) in 2009, President Obama and other world leaders agreed for the first time that all major countries, whether developed or developing, would implement targets or actions to limit greenhouse emissions, and do so under a new regime of international transparency. And in 2011, at the year-end climate meeting in Durban, we achieved another breakthrough: Countries agreed to negotiate a new agreement by the end of 2015 that would have equal legal force and be applicable to all countries in the period after 2020. This was an important step beyond the previous legal agreement, the Kyoto Protocol, whose core obligations applied to developed countries, not to China, India, Brazil or other emerging countries.
The 2015 climate conference is slated to play a critical role in defining a post-2020 trajectory. We will be seeking an agreement that is ambitious, inclusive and flexible. It needs to be ambitious to meet the scale of the challenge facing us. It needs to be inclusive because there is no way to meet that challenge unless all countries step up and play their part. And it needs to be flexible because there are many differently situated parties with their own needs and imperatives, and those differences will have to be accommodated in smart, practical ways.

At the same time as we work toward this outcome in the UNFCCC context, we are making progress in a variety of other important negotiations as well. At the Montreal Protocol, we are leading efforts in support of an amendment that would phase down HFCs; at the International Maritime Organization, we have agreed to and are now implementing the first-ever sector-wide, internationally applicable energy efficiency standards; and at the International Civil Aviation Organization, we have ambitious aspirational emissions and energy efficiency targets and are working towards agreement to develop a comprehensive global approach.

From:	Harman, Donna
To:	Perciasepe.bob@Epa.gov
CC:	Mccarthy, Gina; McCabe, Janet; Tsirigotis, Peter; Wayland, Robertj
Sent:	4/1/2013 4:23:34 PM
Subject:	Boiler MACT Reconsideration Petition
Attachments:	AFPA-AWC Coalition Boiler MACT-GACT-CISWI Reconsideration Petition final 4-1-13.pdf; image001.jpg

Bob,

On behalf of nine trade associations, we are submitting a petition for reconsideration of the Boiler MACT, Boiler GACT, and the Commercial Industrial and Solid Waste Incineration (CISWI) rules. We appreciate the work you, Gina and your staff have done already to make the 2013 rules more achievable. We believe the implementation issues identified in the petition are important and can be addressed by EPA while maintaining the integrity of the underlying rules. As always, we stand ready to meet with EPA staff to discuss our concerns and find workable solutions. Please contact me if you have any questions.

Best regards,

Donna

Donna A. Harman
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********** ATTACHMENT NOT DELIVERED **********

This Email message contained an attachment named
  image001.jpg
which may be a computer program. This attached computer program could
contain a computer virus which could cause harm to EPA's computers,
network, and data. The attachment has been deleted.

This was done to limit the distribution of computer viruses introduced
into the EPA network. EPA is deleting all computer program attachments
sent from the Internet into the agency via Email.

If the message sender is known and the attachment was legitimate, you
should contact the sender and request that they rename the file name
extension and resend the Email with the renamed attachment. After
receiving the revised Email, containing the renamed attachment, you can
rename the file extension to its correct name.

For further information, please contact the EPA Call Center at
(866) 411-4EPA (4372). The TDD number is (866) 489-4900.

********** ATTACHMENT NOT DELIVERED **********

April 1, 2013

The Honorable Robert Perciasepe
Acting Administrator
U.S. Environmental Protection Agency
Room 3000
Ariel Rios Building
1200 Pennsylvania Ave., NW
Washington, DC 20460

Re: Petition for Administrative Reconsideration of the Industrial Boiler MACT, Industrial Boiler GACT, and CISWI Reconsideration Rules

Dear Acting Administrator Perciasepe:

The following parties hereby petition the U.S. Environmental Protection Agency ("EPA" or "Agency") for reconsideration of the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Boiler MACT Reconsideration Rule) (78 Fed. Reg. 7138 (Jan. 31, 2013)); National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers (Boiler GACT Reconsideration Rule) (78 Fed. Reg. 7488 (Feb. 1, 2013)); and Commercial and Industrial Solid Waste Incineration Units: Reconsideration and Final Amendments (CISWI Reconsideration Rule) (78 Fed. Reg. 9112 (Feb. 7, 2013)):

- American Forest and Paper Association (AF&PA)
- American Wood Council (AWC)
- National Association of Manufacturers (NAM)
- Biomass Power Association (BPA)
- Corn Refiners Association (CRA)
- National Oilseed Processors Association (NOPA)
- Rubber Manufacturers Association (RMA)
- Southeastern Lumber Manufacturers Association (SLMA)
- U.S. Chamber of Commerce (Chamber)

Trade association petitioners' member companies own and operate thousands of boilers and process heaters that will be subject to the Boiler MACT, Boiler GACT, or CISWI rules (as amended by the respective reconsideration rules). The petitioners and several member companies submitted extensive comments on the proposed Boiler MACT Reconsideration Rule, Boiler GACT Reconsideration Rule, and CISWI Reconsideration Rule to Docket Nos. EPA-HQ-OAR-2002-0058, EPA-HQ-OAR-2006-0790, and EPA-HQ-OAR-2003-0119, respectively.

We appreciate the fact that the final reconsideration rules include numerous changes that make the amended rules more achievable and workable than the original rules would have been. Nevertheless, there still are several problems with the rules that cause them to be burdensome

and unsupportable by the facts or the law. Accordingly, for the reasons explained below, we petition the Agency for administrative reconsideration of the Boiler MACT Reconsideration Rule, Boiler GACT Reconsideration Rule, and CISWI Reconsideration Rule.

Pursuant to § 307(d)(7)(B) of the Clean Air Act ("CAA"), where it was impracticable to raise an objection during the period of public comment or if the grounds for such objection arose after the public comment period (but within the time specified for judicial review), and if such objections are of central relevance to the outcome of the rule, EPA is authorized to reconsider the rule. Each of the issues detailed below satisfies these criteria for reconsideration.

In addition, we have carefully reviewed the rules, as amended through the reconsideration proceedings, and have identified a number of areas where corrections are warranted for clarification of the standards. We have catalogued these issues in the attached table and request that EPA make the needed corrections and clarifications in its reconsideration of the rules.

1. The Definition of Startup and Shutdown and the Startup Work Practices

The boiler/process heater emission standards apply at all times, except during periods of startup and shutdown, during which times facilities are required to comply with work practices. EPA has improved the startup and shutdown definitions and work practices from those proposed in December 2011, where startup and shutdown periods were based on load. As EPA acknowledges in the preamble, the purpose of industrial boilers and process heaters is to produce steam and heat. Therefore, startup ends when the boiler or process heater begins supplying steam or heat for heating, producing electricity, or both, or for any other purpose. EPA has appropriately excluded a time limit; safety and proper operation of the boiler and associated equipment dictate the amount of time that is needed for startup and shutdown and vary from unit to unit and site to site. EPA has also appropriately eliminated the load threshold from the startup definition. The minimum stable operating load is unit-specific and will vary for different boiler/process heater designs. However, these are new requirements in the Boiler MACT and Boiler GACT rules for which we and other stakeholders have not had the opportunity to comment, and there are several problematic technical issues surrounding these definitions and procedures that must be resolved in order for the rules to be practically implementable. It should be noted that, as this energy is needed for the true manufacturing process, it is in an operator's best interest to reach these operating conditions in the minimum amount of time and as such the duration of these periods will be minimized for economic reasons anyway. But, they cannot be rushed to compromise safety of personnel and equipment.

We have asserted in comments filed on previous versions of the rules that the best way to implement startup work practices is on a site-specific basis. The definition of the end of startup and the required work practices could be reviewed and approved by the permitting agency and incorporated into the Title V operating permit as federally enforceable conditions. At a minimum, EPA needs to consider the various boiler designs and modify the startup definition to account for differences in boiler design.

A new startup work practice requirement in Table 3 of the Boiler MACT rule includes use of one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane,

distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, and liquefied petroleum gas. If you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible. There are several problematic technical issues with this new requirement.

Boiler and process heater operators have a financial incentive to minimize the time spent in startup. When units are starting up, they are not operating in the most efficient mode and the process being served cannot operate optimally. Therefore, boilers and process heaters are started up as expeditiously as possible, but safety concerns cannot be ignored, and proper procedures must be followed. In order to be practically implementable, the startup definition in the Boiler MACT and Boiler GACT rules and the startup work practices in the Boiler MACT rule must take these facts into account and must be revised to accommodate the technical issues discussed below.

A. Start-up

The startup definitions and provisions in the MACT and GACT rules need to be revised in at least three ways: (1) allow more fuels to be "clean fuels," (2) clarify how long clean fuels must be burned, and (3) ESPs must be added to the list of control devices that must be started as expeditiously as possible . The January 31 and February 1, 2013 rules define startup as: "*either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose*."

The act of supplying heat, steam, or electricity does not represent the functional end of the startup period. Some processes are designed such that downstream equipment receives heat and/or steam when fuel is being burned during startup of the boilers and/or process heaters. For example, as a boiler that provides steam to a lumber kiln is starting up, it is preheating the metal steam lines. This preheating is necessary in cold climates where a rush of steam can cause the metal to expand too quickly, resulting in catastrophic damage. This type of operating practice represents efficient use of energy during startup to prepare/preheat process equipment and is a practice EPA should continue to encourage.

Above all, the boiler/process heater operator's primary concern during startup is safety. The startup procedures must ensure that the equipment is brought up to normal operating conditions in a safe manner, and startup ends when the boiler/process heater and its controls are fully functional. The procedures and the time necessary to complete a startup are site specific, and vary by boiler fuel, design, and control technique. The end of startup occurs when safe, stable

operating conditions are reached, after emissions controls are properly operating. The startup provisions should not include requirements that could affect safe operating practices.

(i) Clean Fuels

First, the list of clean fuels, as written, is too narrow. The list needs to be expanded to include all gaseous fuels meeting the "other gas 1" classification. Biodiesel should also be added to the list, as distillate oil is sometimes a biodiesel blend. Fuels that meet the TSM, HCl, and Hg emission limits using fuel analysis should be added to the list of clean fuels. Dry biomass (<20% moisture content) should also be added to the list of clean fuels for units operating with a mechanical collector (i.e., multiclone). Dry biomass is included in EPA's definition of "clean cellulosic biomass" and will burn cleaner than other solid fuels. It is a clean fuel for startup because it exhibits low HCl, Hg, and CO emissions due to its chloride, mercury, and moisture content, and PM emissions would likely be below the dry biomass subcategory PM limit (the AP-42 PM emission factor for a boiler with a mechanical collector firing dry wood is below the dry biomass subcategory PM limit). Therefore it is a reasonable work practice for solid fuel boilers to burn only dry biomass as clean fuel during startup. Permitting authorities should also have the flexibility to approve other clean fuels that EPA may not have considered (e.g., other renewable fuels).

(ii) Ignition

Second, even though the start-up period continues, EPA should clarify that the requirement to use clean fuels ends after ignition OR when you engage the applicable control devices prior to firing other fuels. As currently written, it is not clear whether you must burn clean fuels only for startup (ignition) or for the duration of the startup period as defined in the rule, no matter whether your applicable control devices are engaged. If a boiler is not equipped to burn any of the listed clean fuels, the operator needs the flexibility to be able to start up on the available fuel, as long as applicable emissions controls are engaged. These clean fuels are not universally available in sufficient quantities to be burned from initial startup through normal operating load.

EPA also did not consider the added cost and burden of requiring clean fuel combustion throughout the duration of startup. Specifying the use of only listed clean fuels to startup results in increased capital and operating costs for many facilities and in the increased use of non-renewable fossil fuels; these fuels are in many cases more expensive than a unit's primary operating fuel and require different infrastructure to accommodate (which may not be available, depending on location and other factors). In many cases the boilers must be retrofitted with systems to burn the alternative fuels such as natural gas solely to comply with startup requirements when startup may only occur once or twice per year. This represents a significant expense for a very limited amount of use. Furthermore, many facilities would be required to obtain permit modifications prior to making this change to their boilers. The previous requirement to establish startup procedures that minimize emissions and to train operators made more sense from an operational safety, cost, GHG emissions, and sustainability perspective. Mandated fuel switching for startup would be contrary to the goal of safeguarding fuel diversity,

which is a fundamental objective of U.S. energy policy. A diverse fuel mix protects energy users from fuel unavailability, price fluctuations, and changes in regulatory practices.

(iii) Pollution Control Devices

Third, as currently written, units equipped with an ESP must either fire "clean fuels" throughout startup or engage the ESP when coal, biomass, or residual oil is first introduced into the boiler or process heater. ESPs must be included in the list of air pollution controls that must be started as expeditiously as possible. The ESP cannot practically be engaged until a certain flue gas temperature is reached. Premature starting of this equipment will lead to short-term stability problems that could result in unsafe actions and longer term degradation of ESP performance due to fouling, increased chances of wire damage, or increased corrosion within the chambers. Vendors providing this equipment incorporate these safety and operational concerns into their standard operating procedures.[1]

During periods of startup, combustion begins as fuel is introduced and an ESP warms up on a designated curve that could last for several hours. As the control device is heated up, additional fuel is added until the ESP (and other equipment) meets its design temperature and normal fuel firing is resumed. Some ESPs have oxygen sensors and alarms that shut down the ESP at high flue gas oxygen levels to avoid a fire in the unit. The oxygen level is typically high during startup, so the ESP may not engage due to these safety controls until more stable operating conditions are reached. Therefore, ESPs must be included in the list of air pollution controls that must be started as expeditiously as possible.

(B) Shutdown

The shutdown definitions in the MACT and GACT rules also need to be revised. The January 31 and February 1, 2013 rule definition is: *''Shutdown means the cessation of operation of a boiler or process heater for any purpose. Shutdown begins either when none of the steam and heat from the boiler or process heater is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler or process heater, whichever is earlier. Shutdown ends when there is both no steam or heat being supplied and no fuel being fired in the boiler or process heater.''*

The definition is problematic for units firing solid fuels on a grate or in a fluidized bed combustor where the residual material in the unit keeps burning after fuel feed to the unit is stopped. In this case fuel is still burning ("being fired") in the unit despite the fact that load reduction is occurring, additional fuel is not being fed, and the shutdown process has clearly begun. The shutdown definition should be revised to state that shutdown begins either when none of the steam and heat from the boiler or process heater is supplied for heating and/or producing electricity or when fuel is no longer being fed to the boiler or process heater and that

[1] See Appendix I of AF&PA's August 23, 2010 comments on the June 4, 2010 proposed rule for an excerpt of an ESP operational manual.

shutdown ends when there is both no steam or heat being supplied and no fuel being combusted in the boiler or process heater.

The terms "supplying" and "or for any other purpose" in both the startup and shutdown definitions is too open-ended and could be read to mean that steam and heat supplied for uses within the boiler itself will end the startup period or delay onset of the shutdown period. Many boilers use steam to drive rotating equipment such as feedwater pumps, preheat feedwater, and operate de-aerators. Some of these uses, e.g., operating feedwater pumps and preheating feedwater, begin in the early stages of starting a boiler and continue until the boiler is cooled down. These terms in effect limit the use of energy during startup and shutdown periods for these purposes and inappropriately truncate these periods. As a result, an operator may be motivated to use less efficient and more expensive electrical power where feasible to ensure that adequate conditions are achieved for use of steam in the manufacturing process served by the boiler or process heater. Efficient and cost effective internal uses of steam and heat for operating the boiler should not be discouraged by definitions that unnecessarily limit the duration of the startup and shutdown periods and that may require costly retrofits to boilers with no commensurate environmental benefit.

2. Operating Capacity Limitation

The Boiler MACT rule requires facilities to establish various operating parameter limits during the initial performance test and then monitor those operating parameters as ongoing compliance indicators. Most operating parameters are established based on a minimum or maximum hourly average during the initial performance test and have a 30-day averaging period for ongoing monitoring. The 30-day averaging period accounts for variability in boiler/process heater operation. One such operating parameter is boiler/process heater load. The rule requires operators to maintain the operating load of each unit such that it does not exceed 110 percent of the average operating load recorded during the most recent performance test. The rationale for this operating parameter is that for many pollutants operating at maximum load will produce maximum emissions, and the initial performance test should be conducted at the conditions under which the source could operate in the future that will produce the worst case emissions.

We do not disagree that boiler load is an appropriate operating parameter. In numerous instances, facility air permits already include operating limits related to the boiler load achieved during a prior successful performance test. However, there are two concerns with the specifics of rule requirements for monitoring of operating load. First, the language in Tables 4 (which states what operating limits must be met) and 8 (which sets forth requirements for demonstrating continuous compliance) conflicts with the language in Table 7 (which describes how operating limits are to be established). Table 4, item 8, states that if you are demonstrating compliance using performance testing, you must "maintain the operating load of each unit such that it does not exceed 110 percent of the **highest hourly average** operating load recorded during the most recent performance test." Table 8, item 10, requires "Maintaining the operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test according to 63.7520(c)." Section 63.7520(c) refers to the language in Table 4. However, Table 7, item 5, states that you "Determine the **average of the**

three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit." Therefore, there is a conflict as to whether you use the highest hourly average operating load times 1.1 as the operating limit or the test average operating load times 1.1 as the operating limit. For consistency with other operating parameter limits and to avoid inappropriately limiting boiler/process heater throughput, Table 7, item 5 should be revised to clearly state that the limit is set based on the **highest hourly average** during the test times 1.1.

Second, operating load should have the same averaging period as the other operating parameters (30 days). As stated in comments on the proposed reconsideration rule, averaging periods are appropriate for operating parameters because the standards apply during all operating conditions (excluding startup and shutdown), and operating conditions of industrial boilers and process heaters can be highly variable, especially when fuel mix and load change. The operating parameter ranges will be established using test data obtained at one steady state operating condition, so a 30-day averaging period allows for some fluctuations that will occur over the range of operating conditions. EPA correctly pointed out that variability outside the operator's control such as fuel content, seasonal factors, load cycling, and infrequent hours of needed operation give cause to use a longer averaging period (76 Fed. Reg. 80610). In the final rule, even the emission limits are assigned a 30-day averaging period when continuous emissions monitors are used. In the final area source boiler rule, operating load is assigned a 30-day averaging period (see Table 7 of the area source rule).

There is no justification for treating the load operating parameter differently in the major source rule than the area source rule or differently from how other operating parameters are treated. A 30-day averaging period would be appropriate for the operating load parameter in the major source boiler rule as well. Although many boilers and process heaters operate at fairly constant loads over the course of a 3- to 6-hour performance test, some units provide steam, heat, or both to processes with variable requirements, such as a lumber kiln or other batch process. For facilities that only utilize one boiler or process heater to serve a particular process, it may not be possible to operate at the maximum operating load for an entire stack test without having to vent or "waste" steam not continuously required by process or processes served by the unit (if the unit is even capable of this type of practice). This would waste energy at a time when energy costs are high and it is the goal of both the agency and industry to conserve energy, not waste it.

Along the same lines, if there is no averaging period associated with the operating load requirement, processes that require variable steam or heat could cause the boiler or process heater to instantaneously operate at greater than 110 percent of the average operating load corresponding to the most recent 3- to 6-hour stack test due to a swing in instantaneous process steam demand or heat requirement. An undesirable outcome would be numerous meaningless "deviations" from the load operating parameter range during these short-term operating periods. These false deviations would be completely avoided with the application of the appropriate averaging period and would not be accompanied by any deviations from other operating parameter requirements (or emissions for units with CEMS) due to the application of a 30-day averaging period on almost every other operating parameter and on emissions measured by CEMS. In fact,§ 63.7525(d)(4), which covers requirements for operating limits that require use

of a CPMS other than PM CPMS or COMS, states "you must determine the 30-day rolling average of all recorded readings…"

At a minimum, EPA should acknowledge that the language in Tables 4 and 8 and § 63.7525(d)(4) governs compliance and that the Table 7 language does not mean instantaneous compliance. Alternatively, averaging period decisions can be the purview of the state regulatory authority (many already have been determined through Title V permits). The permit then specifies the details, for instance, that operating load not exceed 110% of the highest load measured during the performance test and how the averaging period for ongoing compliance is determined as a 30-day rolling average.

3. Energy Assessment Requirements

EPA proposed a beyond the floor requirement of an energy assessment in the June 4, 2010 proposed Boiler MACT and Boiler GACT rules. The purpose of the energy assessment was to reduce demand on affected boilers and process heaters by requiring an assessment of energy efficiency opportunities in the operations served by a given boiler or process heater. We provided extensive comments on the proposed energy assessment at that time.[2] Among other things, we explained that EPA does not have authority to impose binding legal requirements on parts of facility that are not within the source category being regulated. In particular, EPA's authority is limited to setting emissions standards "for each category or subcategory of major sources and area sources." CAA § 112(d)(1). EPA defined the source category for these rules to include only specified types of boilers and process heaters and, therefore, those are the only sources for which EPA may set standards under these rules.

We also pointed out that the energy assessment requirement is not an "emissions standard" as that term is defined in the CAA and, therefore, EPA does not have authority to prescribe such requirements. Furthermore, as a practical matter, even if energy efficiency projects are implemented, there is no guarantee that there will be a corresponding reduction in HAP emissions from affected boilers and process heaters.

The energy assessment requirement remained in the March 21, 2011 final rules. We reiterated our opposition to the energy assessment requirement in our petition for administrative reconsideration of the 2011 final rules and our comments on the December 2011 reconsideration proposals.

EPA decided in the final reconsideration rules to again retain the energy assessment requirements. However, changes were made to limit the effort required to conduct assessments and to clarify how much of the facility associated with a given affected boiler must be covered by the assessment. *See* 78 Fed. Reg. at 7146.

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[2] See for example AF&PA comments on June 4, 2010 proposal at EPA-HQ-OAR-2002-0058-3213, pp. 214-244.

We continue to believe, as consistently asserted throughout these Boiler MACT and Boiler GACT rule proceedings, that EPA does not have legal authority to impose the energy assessment requirement and, in any event, that the record fails to demonstrate that such a requirement would be effective in reducing HAP emissions. As a result, we renew our objections to this requirement and ask EPA to eliminate it through a reconsideration proceeding.

4. Corrections and Clarifications

We have identified a number of additional clarifications and corrections that should be made to the final rules, as amended through the final reconsideration rules. Attachment 1 includes a description of these issues and recommended solutions. We ask that EPA make these needed clarifications and corrections in its reconsideration rules.

* * * * * * * * * *

Thank you for your consideration of these important issues. We look forward to working with you to resolve them. Please feel free to contact Tim Hunt at (202) 463-2588 if you have questions or need more information.

Sincerely,

Donna Harman
President and CEO
American Forest & Paper Association
(on behalf of coalition)

Attachment

cc: Gina McCarthy, OAR
Janet McCabe, OAR
Peter Tsirigotis, OAQPS
Robert Wayland, OAQPS

Attachment

Technical Clarifications/Changes Needed to the Boiler Rules

Rule	Citation	Issue	Clarification or Change Needed
Boiler MACT	63.7525(a)(7) "Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart."	The rule states that if you are subject to a CO limit, you must follow 63.7525(a)(1) through (7). 63.7525(a)(7) appears to require an O2 trim system along with use of the CO and O2 CEMs. Other elements of the rule imply that facilities have a choice to utilize an O2 analyzer system (which MAY include an O2 trim system) or a CO/O2 CEMS. The requirement as written is overly restrictive, especially in cases where this technology cannot be effectively implemented, and we do not believe EPA intended to require use of an O2 trim system when a CO/O2 CEMS is used. Therefore, we believe that 63.7525(a)(7) should not apply where facilities are using CO/O2 CEMS or an O2 analyzer system that does not include an O2 trim system.	Clarify that use of O2 trim systems is one option for compliance and not a requirement for all units with a CO limit. Facilities demonstrating compliance with CO limits must EITHER use an oxygen trim system OR an oxygen analyzer system OR a CO/O2 CEMS.
Boiler MACT	63.7515(e) 63.7521(c)(1)(ii)	There is an inconsistency in the rule regarding fuel sampling requirements for facilities using the fuel analysis option. We believe that monthly sampling is sufficient, and that sampling 3 times per month is overly burdensome (and in some months it would be impossible to obtain 3 samples 10 days apart).	Clarify that the rule requires collection of monthly samples collected no less than 14 days apart.

ED_000419-0004578

Rule	Citation	Issue	Clarification or Change Needed
Boiler MACT	63.7550(b)(1) and (2)	The dates for submitting the compliance reports specified in § 63.7550(b)(2) are the same as the end of the reporting periods specified in § 63.7550(b)(1).	Adjust the dates in § 63.7550(b)(2) to provide a 30-day period for report submission.
Boiler MACT	63.7540(a), 63.7555(d)(1), and Table 8	63.7540(a)(2) requires facilities to keep records of the type and amount of fuels burned in each boiler or process heater during the reporting period to demonstrate that the fuel mixture would result in lower fuel input of chlorine, mercury, and TSM than that during the last performance test. We believe EPA inadvertently deleted the "fuel pollutant content" line from Table 8 in the March 2011 final rule and December 2011 proposed reconsideration rule, which clearly stated that the fuel pollutant content comparison was to be performed monthly. The deletion of this item was not explained in any responses to comments or in the preamble and since 63.7555(d)(1) requires monthly fuel use records for each boiler or process heater, it is appropriate to clarify that the fuel pollutant content comparison is to be performed monthly, otherwise a short-term operating limit might be assumed. It is beyond the capability of multi-fuel boiler operators to measure input of each fuel on a short-term basis.	EPA should reinstate the line item for fuel pollutant content in Table 8 of the 2013 rule.

Rule	Citation	Issue	Clarification or Change Needed
Boiler GACT	Table 1 CO limits	Items 1 and 2 in Table 1 specify that units can comply with the CO limit using a 3-run average or a 10-day rolling average (when using CO CEMS). Item 6 CO limit does not include an averaging period.	Add "3-run average or 10-day rolling average" to the CO limit in Table 1, Item 6.
CISWI and MACT	§60.2265 and §60.2875	Definition of "commercial and industrial solid waste incineration includes operating units that fail to keep records of materials other than traditional fuels under section 241.2. A combustion unit that does not burn solid waste cannot be categorized as a CISWI unit and should not be subject to its provisions, recordkeeping or otherwise. Further these provisions would create a presumption of CISWI applicability as an automatic result of a recordkeeping violation. Such a result is inconsistent with EPA's established enforcement response policies that would otherwise provide a more reasonable framework for addressing such recordkeeping violations. Automatic CISWI applicability is not an appropriate result for such a violation.	Change § 60.2265 definition of CISWI by dropping "…If the operating unit burns materials other than traditional fuels as defined in section 241.2 that have been discarded, and you do not keep and produce records as required by section 60.2175(v), the operating unit is a CISWI unit…" Change 60.2875 definition of CISWI by dropping..... "…If the operating unit burns materials other than traditional fuels as defined in section 241.2 that have been discarded, and you do not keep and produce records as required by section 60.2740(u), the operating unit is a CISWI unit…"

Request for EPA Guidance

We request that EPA provide guidance on the following questions and consider whether amendments to the regulatory language are the best way to address these questions to reduce compliance uncertainty.

Question/Issue	**Industry Comments, Interpretation, and Suggested Solution**
Do recordkeeping requirements in the MACT, GACT, and CISWI rules associated with the use of NHSMs **kick-in** as of the effective date of the rule OR only after the facility demonstrates compliance with all applicable limits, either under Boiler MACT, Boiler GACT, or CISWI. The same question also applies to the recordkeeping requirements under CISWI, Boiler MACT, or Boiler GACT.	The applicable recordkeeping requirements would become effective as of the compliance date for the regulation
Is the 60-day notification requirement, applicable for monitoring plans, alternative analytical methods, and performance tests, waived for performance tests triggered by deviations?	Language in 63.7540(a)(18)(ii)(C) related to PM CPMS indicates that deviations in the 30-day rolling average parameter trigger a requirement to repeat the performance test within 30 days of the deviation. The 60-day notification requirement cannot be satisfied for this scenario and should therefore be explicitly waived for retests triggered by deviations. Facility can be covered by previously submitted test protocol and would notify as soon as possible.
When do retest data become effective for use in compliance calculations? The retesting, report submittal, and approval process could take up to 180 days.	Retest data are forward-looking and should become effective for compliance calculations from the day the results of performance test are received (confirmation of the retest). This requirement would be consistent with the rationale in 63.7540(a)(18)(ii)(C) stating that parameter exceedances occurring between the first deviation and the corresponding retest DO NOT count as additional deviations.
When do new fuel and stack test data become effective for use in compliance calculations? When do new parameter limits from the most recent stack test become effective?	The results become effective when they are received and can be used to demonstrate compliance, going forward.

Question/Issue	Industry Comments, Interpretation, and Suggested Solution
Does a liquid fuel unit equipped with a CO CEMS under Boiler MACT have the option to use the CO CEMS to demonstrate compliance with the applicable CO limit? (An alternative CEMS limit has not been established for the liquid subcategory.)	The facility can apply for an alternate monitoring request in this case. The alternate CO CEMS limit would be the same as the short-term limit, and the facility could request an appropriate averaging period.
How are CO data that exceed the span value of the instrument handled in calculating the 30-day averages? (Is the upper limit of the span used to calculate the 30-day rolling average)?	Section 63.7525(a)(2)(iii) cites the requirement to set the span value at 2 times the applicable limit. CO measurements above the span of the instrument are valid unless the value is above the range of the instrument. Values above the range are less reliable and should not be included in the calculation of rolling averages. The range value itself should be used for the rolling average calculation in such cases.

From:	Cole, Jefferson
To:	Stenhouse, Jeb; Adamantiades, Mikhail; Eschmann, Erich; Sims, Ryan
CC:	Kocchi, Suzanne; Fawcett, Allen; Irving, Bill; Ohrel, Sara
Sent:	1/28/2015 11:55:22 AM
Subject:	Draft Biomass Briefing
Attachments:	2015 02 03 Biomass Update v1.pptx

All,

As you may have seen from the updated meeting invite, our briefing with Sarah has been split into two to make sure we cover all topics adequately. Our briefing on biomass comments on 111(d) is now going to take place on Tuesday, Feb. 3 at 2:30pm.

Attached is another version following comments in our discussion yesterday. I've left a couple placeholders in red brackets for your specific attention, but edits/suggestions you have on any aspect of the briefing would be greatly appreciated.

Please send any edits/suggestions you have back to me by COB Wednesday.

In the meantime, if you have any questions, contact me anytime.

Thanks,

Jeff

Jefferson Cole
Economist
Climate Change Division
U.S. EPA
Desk: 202.343.9671
Mobile: 202.701.8795
cole.jefferson@epa.gov

From: Kocchi, Suzanne
To: Gunning, Paul
CC: Fawcett, Allen; Irving, Bill
Sent: 1/7/2015 8:01:59 PM
Subject: Re: just read this

As part of the briefing for Sarah at end of the month Jeff and Erich (or whoever is working on this for CAMD) need to talk to OGC to get their thoughts on initial response to CBD's comments. In addition to talking to Anna's group next week, Jeff and Sara along with CAMD should probably talk to appropriate OGC (I assume it is Howard and Scott Jordan but they should check). Sarah is going to want to hear our "plan" but also want to know OAQPS and OGC positions on comments.

Sent from my iPhone

On Jan 7, 2015, at 7:43 PM, Gunning, Paul <Gunning.Paul@epa.gov> wrote:

FYI

Sent from my BlackBerry 10 smartphone.

From: Dunham, Sarah <Dunham.Sarah@epa.gov>
Sent: Wednesday, January 7, 2015 6:44 PM
To: Gunning, Paul; Harvey, Reid
Cc: Krieger, Jackie
Subject: Fw: just read this

Sent from my BlackBerry 10 smartphone.

From: McCabe, Janet
Sent: Wednesday, January 7, 2015 6:39 PM
To: Goffman, Joseph; Tsirigotis, Peter; Dunham, Sarah
Subject: just read this

Environmentalists Suggest Suit Over EPA's Treatment Of Biomass In ESPS

Posted: January 06, 2015
Environmentalists are suggesting they will sue EPA over its plan to allow states to take greenhouse gas (GHG) credit for the use of biomass under its proposed existing source performance standards (ESPS), saying the plan is unlawful because it assumes the use of out-of-sector emission cuts that are incompatible with the proposal.
EPA Nov. 19 issued a long-awaited policy memo that allows states to rely on biomass obtained from waste and undefined “sustainable” practices to be used for compliance with its ESPS proposal to cut carbon dioxide (CO_2) from the power sector.
The agency's proposal hinged on an argument, pushed by industry and labor groups, that because forest regrowth sequesters CO_2, combustion of biomass is carbon neutral. Environmentalists, however, say some materials burned for energy -- such as whole trees -- are worse for the climate than burning coal because of the dramatic immediate release of GHGs that takes decades to resequester. As a result, many environmentalists have already charged that EPA's proposed approach will increase GHG emissions from generating units that substitute biomass for fossil fuel.

In recently filed comments, they go further, charging that allowing states to take GHG credit for use of biomass as a fuel source goes beyond what the Clean Air Act allows. The Center for Biological Diversity (CBD) argues in its Dec. 1 comments that “to the extent EPA is relying on the ability of 'sustainably managed' forests and agricultural lands to sequester carbon as a general matter, it is effectively proposing to rely on the equivalent of out-of-sector offsets” even though that would contradict the proposed rule's legal rationale.

For example, EPA proposes to allow states to comply with outside-the-fence renewable and efficiency measures under the ESPS because they would reduce power plants' GHG emissions, but the proposal generally does not allow out-of-sector offsets or sequestration that does not result in an actual decrease of generation or emissions at an affected power plant, CBD says.

What EPA proposes for biomass “not only contradicts the fundamental legal rationale underlying the proposed rule, but also runs counter to the plain text of the Clean Air Act,” CBD says. For example, the group says that while section 111 of the law allows EPA to regulate “sources” that “emit” pollutants, and set standards that “reduce” and “limit” those emissions, “there is no room in the statutory language for counting off-site, later-in-time sequestration of CO2 on agricultural or forest lands against the 'emissions' from covered 'sources,' regardless of how those lands and forests are managed.”

Similarly, a coalition of environmental groups including the Clean Air Task Force, National Wildlife Federation, Natural Resources Defense Council, Partnership for Policy Integrity (PFPI), Sierra Club and Southern Environmental Law Center submitted Dec. 1 comments that argue “because the combustion of biomass at affected sources does not lead to actual, real-time emissions reductions at the affected sources, it cannot be a standard of performance.”

The coalition comments recommend changes for using a biomass framework in the ESPS in a way that is scientifically and legally valid. Among other things, the groups say EPA must rely on an anticipated future baseline to model changes in stored carbon; utilize compact timeframes of 10 to 20 years when analyzing net emissions; calculate biogenic emissions and reductions consistently; address leakage by incorporating counterbalancing functions; and categorize biomass feedstocks according to key physical and methodological characteristics.

'Ignoring Emissions'

In their comments, environmentalists also strongly criticize EPA's revised draft biomass accounting framework to determine how to count biomass CO2 emissions when taking into account regrowth and carbon sequestration, a document that will undergo a second round of review by the agency's Science Advisory Board.

PFPI in separate Dec. 1 comments charges that the revised framework -- and EPA's assumption that biomass energy is carbon neutral -- is scientifically flawed and should be overhauled.

“Ignoring emissions from power plants that are primarily fueled by wood and other biomass directly contradicts a plethora of evidence from peer-reviewed journals [and] advice from EPA's own Science Advisory Board,” PFPI says.

The group adds: “There is no faster way to add carbon to the atmosphere than burning and transforming solid materials to CO2. Burning biomass -- even 'waste that would decompose anyway' -- releases carbon from materials and adds net carbon to the atmosphere. While the

net effect of combustion emissions can be offset or diminished over time, such reductions can take years or decades."

The comments say EPA's intention of counting biomass energy but not its emissions in the ESPS is a "fundamental flaw that not only makes a mockery of the so-called scientific review process that EPA employed . . . but also fundamentally reduces the ability of the GHG rule to reduce CO2 emissions from the power sector."

One source notes that EPA's carbon neutrality claims suggest that emissions will be offset "at some future time, in some other place" yet the ESPS "seems to prohibit use of offsets."

Among other arguments, advocates said the policy proposals, including the ESPS, are not supported by the new draft framework. The source says that taken together, the environmental groups' comments to EPA show that "it is absurd to 'reduce' greenhouse gas emissions by increasing them with the use of bioenergy, especially when the total amount of CO2 is unlimited by any cap, and the endorsement of 'sustainably harvested' fuel opens the door to forest harvesting."

Industry Support

By contrast, industry groups in their comments reiterated their earlier support for EPA's proposal, while asking EPA to take further steps to encourage biomass energy, including by defining what is considered sustainable practices.

For example, the Biomass Power Association (BPA) in Dec. 1 comments encourages EPA to "carefully consider the sustainability questions left unanswered . . . to ensure the maximum possible contributions by biomass to the" ESPS.

Also, the American Forest & Paper Association and the American Wood Council in their Dec. 1 comments generally oppose the ESPS as exceeding EPA's authority but also seek more leeway on biomass.

The groups add that "EPA should allow states to consider the use of biomass-derived fuel in affected units as an emission reduction measure" and must distinguish between biogenic CO2 and fossil fuel CO2 to provide a clearer policy pathway for biomass.

"While EPA has made some statements about the positive role for biomass in reducing GHG emissions, the agency has not provided the information needed to understand how bioenergy emissions will be counted toward reducing CO2 emissions under the rule," the groups say.

They also argue that the Nov. 19 documents are "directionally" helpful but do not "indicate the criteria EPA will use to qualify 'sustainably-derived' forest biomass. . . . [W]e remain concerned that EPA could . . . fail to adequately resolve regulatory uncertainty." -- *Dawn Reeves* (dreeves@iwpnews.com)

From:	DeLuca, Isabel
To:	Millett, John; Dennis, Allison; Drinkard, Andrea; Cortelyou-Lee, Jan; Risley, David; Wilson, Erika
CC:	Kocchi, Suzanne; Irving, Bill; Fawcett, Allen
Sent:	11/14/2014 5:24:17 PM
Subject:	Biomass comms. docs
Attachments:	Biomass Framework Q&As 11.14.14 v2.docx; Biomass Memo Q and As - permitting.docx; Biomass Roll out 11 14 14.docx; Biomass-CPP-Questions-v3-11 14 14.docx; Desk Statement 11.14.14.docx; TPs Biomass Outreach.docx

Apologies for the multiple emails, but I wanted to forward the latest versions of the biomass comms docs.

Attached:

- Rollout plan
- Desk statement
- Outreach call talkers
- 3 Q&A docs on the Framework, Permitting, and CPP

Sarah is sharing these with Joe now, so we'll incorporate any edits and send updates Monday. We'll also likely flesh out the outreach talkers to serve as a script for the ADD call Monday afternoon.

Thanks and let me know if you have any Qs or concerns.

Isabel DeLuca
Climate Change Division, US EPA
(202) 343-9247

From: Kocchi, Suzanne
To: Gunning, Paul
CC: DeLuca, Isabel; Irving, Bill; Fawcett, Allen
Sent: 11/14/2014 8:13:11 AM
Subject: FW: Biomass/CPP Q&As
Attachments: Biomass%20CPP%20Questionsv2 (BI).docx

Here is where we are now. Done with our drafts. I recommend we hold on doing anything more until 1) we see if edits come in from OAQPS this morning and 2) we have the 10 am mtg especially given this new language Joe has in the **Ex. 5 - Deliberative**

If you want you can send to Sarah to show her we have something.

From: Irving, Bill
Sent: Thursday, November 13, 2014 9:42 PM
To: Kocchi, Suzanne; DeLuca, Isabel; Fawcett, Allen
Subject: Re: Biomass/CPP Q&As

I only had a few minor comments - not much to add.

From: Kocchi, Suzanne
Sent: Thursday, November 13, 2014 6:11 PM
To: Irving, Bill; DeLuca, Isabel; Fawcett, Allen
Subject: RE: Biomass/CPP Q&As

My thoughts. I deleted some of the repetitive ones. I also slightly changed the order. Bill, you have the pen. Thanks!

From: Irving, Bill
Sent: Thursday, November 13, 2014 5:35 PM
To: Kocchi, Suzanne; DeLuca, Isabel; Fawcett, Allen
Subject: RE: Biomass/CPP Q&As

I can spend some time this evening from home.

From: Kocchi, Suzanne
Sent: Thursday, November 13, 2014 5:34 PM
To: DeLuca, Isabel; Irving, Bill; Fawcett, Allen
Subject: RE: Biomass/CPP Q&As

We've got to draft answers to these. Not sure who else we can ask but us 3. And then they will have to go thru review from CPP folks, OGC, Sarah D etc. Oh and the Janet mtg is 10 am so presumably we need something that is at least done in CCD by then.

From: DeLuca, Isabel
Sent: Thursday, November 13, 2014 5:32 PM
To: Kocchi, Suzanne; Irving, Bill; Fawcett, Allen
Subject: Biomass/CPP Q&As

Here's a Q&A list focused on biomass & the CPP. These include Bill's draft external responses and additional Qs Suzie had identified as needing internal responses. As you're fleshing these out, if you're adding responses for EPA deliberation only, please specify that (e.g., **EPA Internal Response, …**)

In a sec I'll send to the broader group the rollout & desk statement.

From:	DeLuca, Isabel
To:	Gunning, Paul
CC:	Kocchi, Suzanne; Irving, Bill; Fawcett, Allen
Sent:	11/13/2014 9:35:57 AM
Subject:	updated call list
Attachments:	BAF Internal QAs 11 12 14 v2.docx; Biomass Roll out.docx; Desk Statement.docx; EPA biogenic co2 website_updates 11.12.14.docx

Call list with USDA, plus copies of the other comms. materials.

Andrea Drinkard and Jan Cortelyou-Lee (OAQPS) are reviewing these now.

From: Kocchi, Suzanne
To: Sarah Dunham
CC: Dunham, Sarah; Irving, Bill; Fawcett, Allen; Krieger, Jackie
Sent: 8/12/2014 1:23:36 PM
Subject: RE: Draft slides for biomass with Janet/Gina
Attachments: Next Steps on Framework 081214.pptx

Attached are the revised slides. I put the edits in red so you can see them. They are on slides 3, 4, 5, 7, 8, 9 (added a new slide **Ex. 5 - Deliberative**) and 10. In going through your path forward doc to make sure everything matched, I noted **Ex. 5 - Deliberative** **Ex. 5 - Deliberative**

Let us know if you have additional edits.

From: Sarah Dunham [mailto **Ex. 6 - Personal Privacy**
Sent: Tuesday, August 12, 2014 10:38 AM
To: Kocchi, Suzanne
Cc: Dunham, Sarah; Irving, Bill; Fawcett, Allen
Subject: Re: Draft slides for biomass with Janet/Gina

I would focus on the slides for now. After the discussion Thursday there will be more changes probably so I would wait for that mtg to make changes to other docs. Thanks

Sent from my iPad

On Aug 12, 2014, at 10:30 AM, "Kocchi, Suzanne" <Kocchi.Suzanne@epa.gov> wrote:

Ok so we should edit all 3 docs to make sure they are consistent with the points below where there is overlap: 1) the slides 2) path forward doc and 3) cover memo?

We can do that and send all 3 back to you.

From: Sarah Dunham **Ex. 6 - Personal Privacy**
Sent: Tuesday, August 12, 2014 10:28 AM
To: Kocchi, Suzanne
Cc: Dunham, Sarah; Irving, Bill
Subject: Re: Draft slides for biomass with Janet/Gina

Thanks -- this looks like the right ballpark--
-- will you guys go back and look through the document (1-2 pager laying out path forward) we sent to Janet laying out the approach and make sure all the points made in that document and made here (eg, **Ex. 5 - Deliberative** **Ex. 5 - Deliberative**
-- also worth being more explicit **Ex. 5 - Deliberative** **Ex. 5 - Deliberative**
-- I would then **Ex. 5 - Deliberative**

Ex. 5 - Deliberative

-- I like the questions **Ex. 5 - Deliberative** **Ex. 5 - Deliberative**

Thanks

Sent from my iPad

On Aug 12, 2014, at 9:39 AM, "Kocchi, Suzanne" <Kocchi.Suzanne@epa.gov> wrote:

Here are the slides

Sent from my BlackBerry

From: Kocchi, Suzanne <Kocchi.Suzanne@epa.gov>
Sent: Monday, August 11, 2014 5:35 PM
To: Dunham, Sarah
Cc: Krieger, Jackie; Irving, Bill; Fawcett, Allen
Subject: Draft slides for biomass with Janet/Gina

Here are the draft slides we discussed. I am brining a hard copy up now. Happy to revise as you see fit.

Allen will have the power sector table ready for you tomorrow and talk with the team about our internal analysis to fill it in.

<Next Steps on Framework 081114v2.pptx>

From:	Kocchi, Suzanne
To:	Krieger, Jackie; Friedman, Kristina; Mason, Colleen
CC:	Ohrel, Sara; Irving, Bill; Fawcett, Allen; Gunning, Paul
Sent:	7/23/2014 10:00:49 AM
Subject:	FW: slides for Monday biomass briefing with Janet - deliberative
Attachments:	draft Biomass Assessment Framework Briefing for Janet 7-23-14.pptx

Jackie – Sara circulated the slides to the other offices today. She is teleworking tomorrow (during the move) so if Sarah D has comments, Sara O can make them. You can see Sara O's cell phone number below if you need to reach her. With the briefing for Janet on Mon we need to send to the IO on Fri. Given we have no one on Fri to do it we were going to plan to send it up cob tomorrow (when Sara O is done teleworking). Thanks – Suzie

From: Ohrel, Sara
Sent: Wednesday, July 23, 2014 9:51 AM
To: Doster, Brian; Williams, Melina; Jordan, Scott; Hoffman, Howard; Lie, Sharyn; Camobreco, Vincent; Santiago, Juan; Kornylak, Vera S.; Culligan, Kevin; Koerber, Mike; Mangino, Joseph; Levy, Aaron; Montanez, Jessica; Stenhouse, Jeb; Deck, Leland
Cc: Kocchi, Suzanne; Fawcett, Allen; Irving, Bill; Cole, Jefferson
Subject: slides for Monday biomass briefing with Janet - deliberative
Importance: High

Hello everyone,

In preparation for our meeting with Janet on biogenic emissions on Monday, we are sending you our draft slides. We need to finish edits and send the PPT to the OAR IO tomorrow, so please send us your suggested edits no later than close of business today.

Thank you,
Sara

Sara Bushey Ohrel
Climate Economics Branch
Climate Change Division
U.S. Environmental Protection Agency
Phone: (202) 343-9712
Cell: (202) 341-6748

-- this email and its contents are deliberative--do not distribute or cite --

From:	Stenhouse, Jeb
To:	Kocchi, Suzanne; Krieger, Jackie; Friedman, Kristina; Mason, Colleen
CC:	Fawcett, Allen; Irving, Bill; Harvey, Reid; Gunning, Paul; Deck, Leland
Sent:	7/22/2014 5:26:15 PM
Subject:	RE: Biomass Briefing for Janet - latest version - use this to incorporate any edits from Sarah D
Attachments:	Biomass Accounting Framework Briefing for Janet - 07-22-14v2.pptx

Hi Suzie – let's touch base tomorrow (Weds) to confirm whether Leland in my group can take the pen on this for the rest of the week when CCD is out of commission for the move – but it would work best if he had cell numbers to confer with key folks in CCD if the edits are not straightforward/simple. Anyway, let's chat tomorrow to confirm!

Jeb

From: Kocchi, Suzanne
Sent: Tuesday, July 22, 2014 4:54 PM
To: Krieger, Jackie; Friedman, Kristina; Mason, Colleen
Cc: Fawcett, Allen; Irving, Bill; Stenhouse, Jeb; Harvey, Reid; Gunning, Paul
Subject: FW: Biomass Briefing for Janet - latest version - use this to incorporate any edits from Sarah D
Importance: High

FYI – Paul just gave these slides to Sarah for her review. This version has one bullet added on slide 11 that Jeb included after Paul gave these slides to Sarah. Given everyone will be out after tomorrow and these are due to IO NLT Fri (Janet briefing is Mon am), sending these to you now. Sarah D told Paul she wasn't sure when she would have edits but we won't really have access/ability to make edits after tomorrow so not sure how we want to handle. Really just trying to make sure multiple people have the file in case something needs to be edited and/or sent up on Fri.

Maybe CAMD could make the edits if she has them after tmrw because they should still be connected…?

From: Kocchi, Suzanne
To: Gunning, Paul
CC: Fawcett, Allen
Sent: 7/22/2014 12:59:23 PM
Subject: review this version
Attachments: Biomass Accounting Framework Briefing for Janet - 07-22-14_sk.pptx

Paul – Look at this version. I tried to capture our discussion this am.

From: Kocchi, Suzanne
Sent: Tuesday, July 22, 2014 12:59 PM
To: Fawcett, Allen; Irving, Bill; Cole, Jefferson; Ohrel, Sara; Gunning, Paul; Adamantiades, Mikhail; Deck, Leland; Stenhouse, Jeb; Sherry, Christopher
Subject: RE: Biomass Briefing for Janet

All – Based on a conversation with Paul I have slightly revised slides 10-12.

Paul is going to look now and will provide us further comment (if you see something that I changed that raises red flags please let us know so we can make those edits along with Paul's).

Thanks!

From: Fawcett, Allen
Sent: Tuesday, July 22, 2014 8:55 AM
To: Irving, Bill; Cole, Jefferson; Ohrel, Sara; Gunning, Paul; Kocchi, Suzanne; Adamantiades, Mikhail; Deck, Leland; Stenhouse, Jeb; Sherry, Christopher
Subject: RE: Biomass Briefing for Janet

Thanks for the comments everyone. Here's an updated version incorporating all the edits I've received so far.

Allen

From: Irving, Bill
Sent: Monday, July 21, 2014 5:37 PM
To: Cole, Jefferson; Ohrel, Sara; Fawcett, Allen; Gunning, Paul; Kocchi, Suzanne; Adamantiades, Mikhail; Deck, Leland; Stenhouse, Jeb; Sherry, Christopher
Subject: RE: Biomass Briefing for Janet

+ Chris

Revisions attached in red

Slide 3 – slight tweak to **Ex. 5 - Deliberative**
Ex. 5 - Deliberative

Slide 5 – moved last bullet point to one level higher in hierarchy

Switched order of slide 7 and 8. Need to describe application before going to blue/green table, and also slide 9 should be ordered after the blue/green table.

New Slide 7 – small addition to indicate the relationship between illustrative values, and the chart.

New Slide 8 – Changed title. **Ex. 5 - Deliberative**
Ex. 5 - Deliberative

Slide 9 – Changing Ex. 5 - Deliberative

Ex. 5 - Deliberative

Ex. 5 - Deliberative

Slide 10 – Edit to title to give an indication of what the option is about. Added a point about Ex. 5 - Deliberative

Ex. 5 - Deliberative

Slide 11 – Edited the title. Question/comment about timing of public notice and comments, added something related to Chris' point about a guidance document.

From: Cole, Jefferson
Sent: Monday, July 21, 2014 5:25 PM
To: Ohrel, Sara; Fawcett, Allen; Gunning, Paul; Irving, Bill; Kocchi, Suzanne; Adamantiades, Mikhail; Deck, Leland; Stenhouse, Jeb
Subject: RE: Biomass Briefing for Janet

My comments:

- On Slide 7/9: agree with choice not to break up the table on slide 7, but rather discuss the implications of Ex. 5 - Deliberative on slide 9.
- On Slide 8: at the end of 3rd bullet, *add*: Ex. 5 - Deliberative

  Ex. 5 - Deliberative
- On Slide 9: concur with Sara's recommendation regarding Ex. 5 - Deliberative in first bullet.
- Recommend swapping positions for Slides 7 and 8. Slide 9 is a good follow up immediately after Slide 7. Slide 8 could also make sense as a way of introducing what we are finding, as presented in Slide 7. *Note: this is not a strong recommendation.*

Thanks,

Jeff

From: Ohrel, Sara
Sent: Monday, July 21, 2014 5:10 PM
To: Fawcett, Allen; Gunning, Paul; Irving, Bill; Kocchi, Suzanne; Cole, Jefferson; Adamantiades, Mikhail; Deck, Leland; Stenhouse, Jeb
Subject: RE: Biomass Briefing for Janet

Hi Allen,
Looks good. I didn't put in line edits into the PPT in case others were also working it right now, but here are my general comments.

On slide 8:
- Ex. 5 - Deliberative – suggest moving the 3rd bullet to being a subbullet under first bullet

Slide 9:

Ex. 5 - Deliberative

offices that did not participate in today's meeting).

Ex. 5 - Deliberative

Slide 10:
- 4th bullet, first subbullet: suggest adding to the end Ex. 5 - Deliberative

Thanks Allen, happy to discuss if you like.

Sara

From: Fawcett, Allen
Sent: Monday, July 21, 2014 4:37 PM
To: Gunning, Paul; Irving, Bill; Kocchi, Suzanne; Ohrel, Sara; Cole, Jefferson; Adamantiades, Mikhail; Deck, Leland; Stenhouse, Jeb
Subject: Biomass Briefing for Janet

Here's my attempt at incorporating Sarah's comments into the briefing. I tried to capture all the suggestions, but let me know if I missed something, or if you have any edits.

Thanks,
Allen

From: Cole, Jefferson
To: Culligan, Kevin
CC: Fawcett, Allen; Irving, Bill; Ohrel, Sara
Sent: 6/26/2014 11:42:55 AM
Subject: Biomass Assessment Framework
Attachments: Appendix_A_IPCC_Emissions Inventory_5 1_Final.docx; Appendix_B_Temporal Scale_5 1_Final.docx; Appendix_C_Spatial Scale_5 1_Final.docx; Appendix_D_Feedstock Categories_5 1_Final.docx; Appendix_E_Discussion of Leakage Literature_5 1_Final.docx; Appendix_F_General Algebraic Representation_5 1_Final.docx; Appendix_G_Process Attributes 5 1_Final.docx; Appendix_H_Reference Point Landscape Attributes_5 1_Final.docx; Appendix_I_Reference Point Baseline Case Studies_5 1_Final.docx; Appendix_J_Anticipated Baselines Background_5 1_Final.docx; Appendix_K_Anticipated Baseline Construction Methods_5 1_Final.docx; Appendix_L_Anticipated Baseline Case Studies_5 1_Final.docx; Appendix_M_Summary of Illustrative Forest and Ag Case Studies_5 1_Final.docx; Appendix_N_Waste Derived Feedstocks_5_1_Final.docx; Framework_Report_5 1_Final.docx; SAB_Response_Document_5 1_Final.docx

Kevin,

Per your request, here is the current draft of the framework for your reference. This includes several documents, including the main report, a series of technical appendices (A through N), and a Response Document to the SAB. If you have any questions, please feel free to contact us anytime.

Regards,

Jefferson Cole

From: Kocchi, Suzanne
To: Gunning, Paul
CC: Fawcett, Allen; Irving, Bill
Sent: 6/13/2014 4:17:22 PM
Subject: biomass to do list
Attachments: Task list June 12v2.docx

Attached is Sara and Jeff's to do list on the biomass stuff we talked about the other day. Allen may have passed this on but in case he didn't you have it here. Bottom line, they are aiming for the next version on the report, mid-july. Likely right before the move. Both Sara and Jeff will be out for some period of time in June so it isn't the best time for quick turns.

Schedules:
Jeff out: June 16-23, 25-27 (work travel); Sara out: June 20-29 (vacation)

Task list:

Ex. 5 - Deliberative

Ex. 5 - Deliberative

To: Irving, Bill[Irving.Bill@epa.gov]; Fawcett, Allen[Fawcett.Allen@epa.gov]
Cc: Cole, Jefferson[Cole.Jefferson@epa.gov]
From: Ohrel, Sara
Sent: Thur 1/16/2014 7:37:08 PM
Subject: draft PPT for Sarah briefing
MAIL_RECEIVED: Thur 1/16/2014 7:37:14 PM
Biomass update for Sarah 1 23 2014 v7.pptx

Hi Allen and Bill,

Please review the updated PPT per the Paul briefing.

Thanks,

Sara

Sara Bushey Ohrel

Climate Economics Branch

Climate Change Division

U.S. Environmental Protection Agency

Phone: (202) 343-9712

Cell: (202) 341-6748

From:	Jenkins, Jennifer
To:	Srivastava, Amit; Swanson, Nicholas; Schrock, Bill; Deck, Leland; Eschmann, Erich
CC:	Irving, Bill; Sherry, Christopher; Ohrel, Sara; Culligan, Kevin; Dunkins, Robin; Cole, Jefferson; Spence, Kelley; Bradfield, John; McLamb, Marguerite; Fawcett, Allen
Sent:	11/14/2013 1:58:31 PM
Subject:	RE: Discussion on OAP expertise re: biomass neutrality/economics
Attachments:	feedstock list for AF2.pptx

All:

As we discussed during the meeting yesterday, I am attaching the working list of feedstocks that we have identified for use in the next draft of the Accounting Framework for Biogenic CO2 Emissions. Hopefully this is useful for considering how EPA might approach biogenic CO2 in the programs we discussed yesterday.

Let us know if you have questions. Also, since this has not been circulated outside EPA please treat it as confidential.

thanks
Jen

Jennifer C. Jenkins, Ph.D.
Climate Policy Branch
Climate Change Division, Office of Atmospheric Programs
US Environmental Protection Agency
202-343-9361
jenkins.jennifer@epa.gov

-----Original Appointment-----
From: Srivastava, Amit
Sent: Tuesday, October 22, 2013 3:12 PM
To: Srivastava, Amit; Jenkins, Jennifer; Swanson, Nicholas; Schrock, Bill; Deck, Leland; Eschmann, Erich
Cc: Irving, Bill; Sherry, Christopher; Ohrel, Sara; Culligan, Kevin; Dunkins, Robin; Cole, Jefferson; Spence, Kelley; Bradfield, John; McLamb, Marguerite; Fawcett, Allen
Subject: Discussion on OAP expertise re: biomass neutrality/economics
When: Wednesday, November 13, 2013 3:00 PM-4:00 PM (GMT-05:00) Eastern Time (US & Canada).
Where: RTP-OAQPS-541-4486-SPPD/Phone-Line/RTP-OAQPS-BLDG-C; RTP-OAQPS-E141B/RTP-OAQPS-BLDG-E

<< File: Update on OAQPS Biomass Strategy11132013.pptx >>

11/6/2013
Hi all, sorry for the many calendar changes. I am doing my best to ensure all key players from OAP can attend.

October 2013
Hi Jen and Sara,

Bill Schrock, Nick Swanson and I belong to Robin Dunkin's group in SPPD. We are currently brainstorming biomass strategies. During conversations with Kevin, it was advised that we start opening communication channels with your team so we can have access to your technical understanding of biomass neutrality. We also hope to have a technical expert from OAP working closely with us.

Agenda:

1. Introductions - Team roles
2. OAQPS shares our current status on developing a biomass strategy
3. OAQPS shares our current data gaps
4. OAQPS shares identified data needs
5. OAP feedback/discussion
6. Next steps

Jen and Sara, please let me know if you have any further questions on the purpose of the meeting. But this is simply a kick-off to develop a collaboration and to start obtaining key carbon neutrality/biomass economics analyses from your folks.

From:	Andy Bessler
To:	A-AND-R-DOCKET
CC:	Childers, Pat; Wilson, Erika; Shaw, Betsy; Mckelvey, Laura; Colon, Toni; Cristina Gonzalez-Maddux; Mehrdad.Khatibi@NAU.EDU; ann-marie.chischilly@nau.edu; Dunham, Sarah; Angela Benedict (angela.benedict@srmt-nsn.gov); bhoover@ldftribe.com (bhoover@ldftribe.com); Bill.Thompson@Penobscotnation.org; air@lldrm.org; joseph.painter@winnebagotribe.com; katerenw@nc-cherokee.com; Kellie Poolaw (kelliej@pawneenation.org); greenleaf@kootenai.org; lweeks@nemont.net; Matthew Malimanek (santeeair@gmail.com); rmccullers@pci-nsn.gov; randya@cskt.org; rkalistook@nativecouncil.org (rkalistook@nativecouncil.org); sflensburg@bbna.com (sflensburg@bbna.com); Tammy Belone (tammy.belone@jemezpueblo.org); twalea@spokanetribe.com; wilfred.nabahe@crit-nsn.gov
Sent:	10/15/2014 2:22:05 PM
Subject:	NTAA Comments: Docket ID No. EPA-HQ-OAR-2013-0602
Attachments:	NTAA comment letter on EPA's Clean Power Plan, Docket Number ID No. EPA-HQ-OAR-2013-0602.pdf

Please find the attached comments from the National Tribal Air Association on EPA's Clean Power Plan.

Thank you for your consideration of these comments.

Andy

Andy Bessler
Project Director
NTAA
National Tribal Air Association
P.O. Box 15004
Flagstaff, AZ 86011-5004
Office: 928-523-0526
Cell: 928-380-7808
Fax: 928-523-1266
www.ntaatribalair.org

NTAA

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National Tribal Air Association
P.O. Box 15004
Flagstaff, AZ 86011-5004

Executive Committee

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Colorado River Indian Tribes

Region 10
Kevin Greenleaf
Kootenai Tribe of Idaho

Twa-le Swan
Spokane Tribe

Alaska
Rosalie Kalistook
Treasurer
Orutsararmuit Native Council

Sue Flensburg
Bristol Bay Native Association

October 15, 2014

U.S. Environmental Protection Agency
EPA Docket Center (EPA/DC)
Mail Code 28221T
Attention Docket ID No. EPA-HQ-OAR-2013-0602
1200 Pennsylvania Ave., NW
Washington, DC, 20460

Subject: Proposed Rule for Carbon Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units

Introduction

The National Tribal Air Association (NTAA) is pleased to submit these comments regarding the U.S. Environmental Protection Agency's (EPA)'s proposed rule for Carbon Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34830 (June 18, 2014) (Proposed Rule).

The NTAA is an autonomous organization with 85 principal member Tribes. The organization's mission is to advance air quality management policies and programs, consistent with the needs, interests, and unique legal status of Indian Tribes. As such, the NTAA uses its resources to support the efforts of all federally recognized Tribes in protecting and improving the air quality within their respective jurisdictions. Although the organization always seeks to represent consensus perspectives on any given issue, it is important to note that the views expressed by the NTAA may not be agreed upon by all Tribes. Further, it is also important that EPA understands interactions with the organization do not substitute for government-to-government consultation, which can only be achieved through direct communication between the federal government and Indian Tribes.

The NTAA approves generally of the Proposed Rule. The standards under the Proposed Rule will help reduce carbon dioxide (CO_2) emissions from existing electric generating units (EGUs) that have gone uncontrolled for a very long time. Further these standards supplement very well the standards proposed by EPA earlier in 2014 regarding CO_2 emissions from new EGUs. As a complement to the NTAA's general approval of the Proposed Rule, the NTAA provides its comments and recommendation regarding the four building blocks of the rule, multistate plans, cap-and-trade programs, environmental justice, and Tribal consultation. However,

the NTAA prefaces its comments and recommendations by advising EPA about what climate change means to Indian Tribes.

Indian Tribes and Climate Change

EGUs are the single largest source of CO_2 pollution in our nation, emitting approximately 2.3 billion tons annually which comprises 40% of the carbon pollution emitted in the U.S.[1] EPA provides that greenhouse gas (GHG) pollution threatens public welfare in a number of ways by contributing to long-lasting changes in our climate that can have a range of negative effects on human health and the environment.[2] The impacts vary regionally and seasonally and may include longer, more intense and more frequent heat waves; more intense precipitation events and storm surges; less precipitation and more prolonged drought; and increased ground level ozone pollution which increases the risk of morbidity and mortality.[3] Further, climate change exacerbates higher temperatures which, in turn, increase air pollution such as ground-level ozone that can trigger asthma attacks and other health conditions. The negative health effects associated with air pollution are especially damaging for vulnerable populations including the elderly, young children, and those individuals already in poor health.[4]

Indian Tribes are not immune from the effects of climate change. Like the rest of the nation, its populations are suffering from the health effects of climate change. Further, Tribes are seeing the effects of climate change through increased storm surges, erosion, and flooding; prolonged droughts never seen in modern times; and increased fires and insect pest outbreaks in their forests.[5] These are just a few snapshots of what is happening on and around the lands of this nation's 566 federally recognized Tribes.

Indian Tribes are affected much differently than the rest of the nation as their cultures are integrated into the ecosystems of North America; and many Tribal economies are heavily dependent on the use of fish, wildlife, and native plants. Even where Tribal economies are integrated into the national economy, Tribal cultural identities continue to be deeply rooted in the natural environment. As climate change disrupts biological communities, the survival of some Tribes as distinct cultures may be at risk. The loss of traditional cultural practices, due to climate-driven die-off or range shift of culturally significant plant and animal species, may prove to be too much for some Tribal cultures to withstand on top of other external pressures that they face.

Climate-driven disruption of biological communities is also having a considerable effect on the treaty rights of Indian Tribes. Many such treaties preserve hunting, fishing, and gathering rights for Tribes on their lands and in the usual and accustomed areas. Some Tribes are finding that the animals and/or plants on which they depend for their cultural practices and identity have

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[1] *See* "EDF Welcomes First National Carbon Pollution Standards for Power Plants," Environmental Defense Fund (September 30, 2013), at http://www.edf.org/media/edf-welcomes-first-national-carbon-pollution-standards-power-plants (last visited on July 14, 2014).
[2] Proposed Rule at 34842.
[3] *Id.*
[4] *Id.* at 34949.
[5] The Proposed Rule also indicates that, based on studies completed by EPA, climate change may exacerbate existing environmental pressures on Alaskan Indigenous communities. *Id.* at 34842.

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either migrated to lands not under their control or have disappeared altogether. How does one begin to value this type of loss for a Tribe? Further, CO_2 emitted today can remain in the atmosphere up to 100 years, meaning that the full impacts of these emissions on Tribes and their culture may not be seen until many years into the future.

Regional Climate Change Impacts

In May, 2014 NTAA released the Status of Tribal Air Report that highlights regional impacts from climate change:

> Alaska: There is coastal erosion; melting permafrost threatens civil infrastructure in remote villages as well as food security as underground food cellars thaw; and Alaska Native Villages are unique because they face firsthand the effects of climate change, which has already resulted in the relocation of several villages away from eroding coastlines. A 2003 U.S. General Accountability Office study identified more than 200 Alaska Native Villages affected to some degree by flooding and erosion and 31 villages facing imminent threats that are compelling them to consider permanent relocation. The U.S. Army Corps of Engineers' March 2009 Alaska Baseline Erosion Assessment identified many villages threatened by erosion, but did not assess flooding impacts. At least 12 of the 31 threatened villages have decided to relocate—in part or entirely—or to explore relocation options (GAO, 2009).
>
> Northwest: Changes in hydrology and water chemistry impact fisheries resources and shellfish (ocean acidification); and storm surges threaten coastal areas and Tribal lands along the coasts, which may result in the possible relocation of Tribes.
>
> Southwest: Increased aridity threatens vegetation that is critical for stabilizing sediments which can lead to greater more severe and frequent dust storms and dune mobilization. Higher temperatures and increased droughts will lead to more intense forest fires and reduced grazing potential.
>
> Plains: There are spreads of pests that previously could not survive cooler climates, potential increases in weed species due to more carbon dioxide in the atmosphere, higher temperatures, and changes in precipitation and decreases in soil moisture and water availability. The region's main water supply, the Ogallala Aquifer, is also threatened. Without alternative resources and better water management practices, projected temperature increases; more frequent droughts, and higher rates of evaporation are likely to further stress the water supply.
>
> Great Lakes: Heat waves are becoming more frequent, cold periods are becoming more rare, and snow and ice are arriving later in the fall and melting earlier in the spring. Ticks and mosquitoes will survive in greater numbers as winters become milder and will increase the risks of spreading diseases such as Lyme disease and West Nile virus.
>
> Gulf Coast: Projected sea level rise, increased hurricane intensity, and associated storm surges may lead to further erosion, flooding, and property damage in the Southeast.
>
> Northeast: Projected increases in heavy precipitation and likely sea level rise may lead to more frequent, damaging floods in this region. Large portions of the region may become unsuitable for growing some fruit varieties and some crops, such as cranberries, apples, blueberries, grain, and soybeans. Similarly, by the end of the century, only a small portion of the Northeast may be suitable for maple syrup production. In contrast, the

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region could see a longer growing season for a number of other crops, which would provide potential benefits to society.

NTAA recognizes that EPA's proposed rule is a positive action towards reducing uncontrolled CO_2 emissions as well as the emissions of other GHGs must stop in order to protect Indian Tribes and their cultures, not only for current generations, but also for future generations to come.

Building Blocks

The NTAA finds that EPA could better highlight the theme of this proposed rule that relies on several building blocks rather than the somewhat misleading title that it gives the Proposed Rule, "Carbon Guidelines for Existing Stationary Sources: Electric Utility Generating Units." On its face, the Proposed Rule appears to be focused solely on the existing EGUs that are injecting vast amounts of CO_2 into the atmosphere, but this is not the case. Instead, EPA recommends a portfolio of four building blocks, also known as the Best System of Emission Reduction (BSER), which states can use to meet their overall CO_2 emission reduction requirements as provided under the Proposed Rule. While the building blocks will help reduce CO_2 emissions, the NTAA finds that EPA must place more emphasis on accomplishing CO_2 emission reductions from existing EGUs and address proactively some building blocks whose use could manifest some unexpected environmental issues.

Building Block 1. Reduce carbon intensity of generation at individual EGUs through heat rate improvements on the average of 6%.

The NTAA supports this Building Block and finds that Building Block 1 is the only such building block that focuses on the reduction of CO_2 emissions from EGUs. EPA must do more to promote use of this building block if the real intent of the Proposed Rule is to help reduce these emissions. As such, the NTAA recommends that EPA work closely with states in order to get them to place a greater emphasis on Building Block 1 within their state implementation plans for reducing the CO_2 emissions of existing EGUs within their borders. This should help spur a technology innovation among the EGUs to meet their emission reduction requirements in accordance with Building Block 1, and in turn, help reduce the co-pollutants of such EGUs (*e.g.*, sulfur dioxide (SO_2), nitrogen oxides, and toxic air pollutants).

Further, EPA should encourage states to require individual EGUs to improve their heat rates beyond the 6% identified above. EPA indicates that individual EGUs, on average, could achieve total heat rate improvements of 10% at a reasonable cost, a 6% rate improvement attributable to adoption of best practices for operation and maintenance, and a 4% rate improvement attributable to equipment upgrades.[6] As such, the NTAA recommends that EPA modify Building Block 1 by increasing to 10%, the average amount of heat rate improvements that should be achievable by individual EGUs.

Building Block 2. Substitute energy from most carbon-intensive EGUs with energy from less carbon-intensive EGUs (such as Natural Gas Combined Cycle EGUs).

[6] Proposed Rule at 34856.

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EPA finds that the burning of natural gas produces lower quantities of CO_2 than that produced by the burning of coal or oil.[7] However, concerns have been raised by a number of individuals and groups about the effects of natural gas extraction on drinking water supplies due to the use of fracking. Fracking is a process of drilling and injecting fluid into the ground at a high pressure in order to fracture shale rocks to release the natural gas inside.[8] While the NTAA is not opposed to substituting energy from the most carbon-intensive EGUs with energy from lesser carbon-intensive EGUs, such as those using natural gas, we recommend nevertheless that the Proposed Rule acknowledge the potential dangers of fracking associated with natural gas extraction and that states take all precautions necessary to protect drinking water supplies from the effects of fracking.

Further, natural gas extraction is subject to leakage and loss of methane during transportation.[9] Methane is a powerful GHG whose atmospheric lifetime is much shorter than CO_2, but whose comparative impact on climate change is over 20 times greater than CO_2 over a 100-year period.[10] Studies indicate that methane leakage at levels above 3% is enough to negate the climate benefits of natural gas over coal.[11] The NTAA understands that EPA may be proposing in the near future a rule that addresses methane emissions from EGUs and other sources. The NTAA welcomes such a rule and recommends that EPA look for guidance from those states that have already implemented measures to address methane emissions such as Colorado, which has a comprehensive plan for cleaning up methane pollution from its natural gas sector,[12] and Ohio, which requires natural gas drillers to conduct quarterly inspections to detect and fix leaks in their systems.[13]

Building Block 3. Substitute energy from EGUs with energy from EGUs having low- or zero-carbon generation (*e.g.,* solar, wind, nuclear, biomass).

NTAA strongly supports the use of renewable energy as a way to reduce carbon emissions. EPA proposes the use of nuclear energy as a source having zero-carbon generation that can substitute energy from EGUs.[14] The Proposed Rule indicates that five nuclear power

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[7] *See* "Natural Gas, Air Emissions," U.S. Environmental Protection Agency, at http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html (last visited on September 14, 2014).
[8] *See* "Increased stray gas abundance in a subset of drinking water near Marcellus shale gas extraction," Proceedings of the National Academy of Sciences of the United States of America, vol. 110, No. 28 (July 9, 2013), at http://www.pnas.org/content/110/28/11250.full (last visited on June 27, 2014).
[9] *Id.*
[10] *See* "Overview of Greenhouse Gas Emissions, Methane," U.S. Environmental Protection Agency, at http://epa.gov/climatechange/ghgemissions/gases/ch4.html (last visited on September 2, 2014).
[11] *See* "Leaky Methane Makes Natural Gas Bad for Global Warming," Scientific American, at http://www.scientificamerican.com/article/leaky-methane-makes-natural-gas-bad-for-global-warming/ (last visited on September 14, 2014).
[12] *See* "Colorado adopts tougher air rules for oil, gas industry," at http://www.denverpost.com/environment/ci_25213661/colorado-adopts-tougher-air-rules-oil-gas-industry (last visited on September 14, 2014).
[13] *See* "Ohio becomes third state to impose rules to curtail 'fugitive emissions' from drilling operations," at http://www.ohio.com/news/ohio-becomes-third-state-to-impose-rules-to-curtail-fugitive-emissions-from-drilling-operations-1.478621 (last visited on September 14, 2014).
[14] Proposed Rule at 34870.

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plants are under construction and six others are near retirement which could realistically continue to operate.[15] The NTAA does not have specific position on the use of nuclear energy as a renewable energy source.[16] However, our organization takes this opportunity to identify concerns with nuclear energy's continued use. A few years back, the U.S. Department of Energy (DOE) convened a Transportation External Coordination (TEC) Working Group whose purpose was to "improve coordination with external groups interested in DOE transportation activities,"[17] largely related to the transportation of nuclear waste to a long-term nuclear waste storage site. Indian Tribes were concerned about transporting nuclear waste across and near their lands, and storing the nuclear waste at Yucca Mountain, land culturally important to the Western Shoshone and Southern Paiute peoples.[18] On more than one occasion, DOE representatives mentioned during TEC Working Group meetings that there were at least 56 lawsuits pending against the federal government, filed by the owners and/or operators of nuclear energy facilities who had been promised their nuclear waste would be stored in a long-term storage site.[19] Congress cancelled federal government plans to use Yucca Mountain as a long-term nuclear waste storage site. However, a location for such storage remains necessary and will eventually occur.

The Proposed Rule, in promoting the use of nuclear energy, will help increase the amount of waste[20] that could one day be transported across or near Tribal lands, and ultimately be stored on lands culturally important to Indian Tribes. Further, its promotion as a renewable energy source could cause increased pressure on some Tribes to open up their lands to uranium mining to support nuclear energy use. Similar mining has been done in the past. However, an inventory of abandoned mines from this mining has yet to be completed; and the uranium tailings from this mining are not cleaned up to acceptable health, safety, and environmental standards. EPA doesn't find that the potential disadvantages of nuclear waste relative to fossil fuel-fired generation outweighs nuclear generation's other advantages as an element of Building Block 3.[21] The NTAA disagrees and recommends that EPA engage in a government-to-government consultation with Tribes and to include other federal agencies such as DOE, to discuss and address the prospective issues of transporting and/or storing nuclear waste across or near Tribal lands, and legacy waste.

Further, the Proposed Rule promotes the use of biomass-derived fuels as renewable energy[22] which can include agricultural waste, municipal waste, and wood waste. However, EPA's Scientific Advisory Board finds that biomass fuels are not carbon neutral and can, in fact, be more carbon-intensive than coal.[23] Also, in 2013, the U.S. Court of Appeals struck down

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[15] *Id.*
[16] NTAA, however, points out that EPA does not list nuclear energy as a renewable energy source at http://www.epa.gov/statelocalclimate/local/topics/renewable.html
[17] *See* "Historical Information on the Transportation External Coordination Working Group (TEC)," at http://energy.gov/em/historical-information-transportation-external-coordination-working-group-tec (last visited on September 14, 2014).
[18] *Id.*
[19] *Id.*
[20] As of May 2014, the U.S. has almost 72,000 metric tons of spent nuclear fuel in storage from commercial power generation. *See* "Frequently Asked Questions about Nuclear Waste," Bipartisan Policy Center, at http://bipartisanpolicy.org/projects/energy/nuclear-waste/FAQs (last visited on September 14, 2014).
[21] Proposed Rule at 34883.
[22] *Id.* at 34924.
[23] *See* Mary S. Booth, PhD, "Trees, Trash, and Toxics: How Biomass Energy Has Become the New Coal,"

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EPA's exemption of all new power plants that burn biomass and similar sources of biogenic carbon emissions from the same pollution control requirements that other large facilities have to follow.[24] The NTAA does not take a position on the use of biomass-derived fuels as a number of Indian Tribes use such fuels. However, the NTAA does recommend that a cap be placed on the allowable amount of biomass burning allow in a state's plan, at least until EPA updates its draft accounting framework regarding biomass-derived fuels that should help determine the net atmospheric contribution of CO_2 related to the growth, harvest and use of these fuels.

Building Block 4. Reduce EGU energy by the use of demand-side energy efficiency that reduces the amount of generation required (e.g., reduce demand for electricity through building codes, state appliance standards).

The NTAA supports the implementation of Building Block 4.

Finally, EPA seeks comments on an alternative BSER that uses Building Blocks 1 and 2 only. EPA indicates that limiting use of these two building blocks as the BSER would achieve fewer CO_2 emission reductions at a higher overall cost.[25] The NTAA finds that EPA's preferred approach of using a BSER that consists of all four building blocks is a better approach versus one that only uses Building Blocks 1 and 2. However, this does not negate our comments above regarding our concerns with some of the building blocks.

Multistate Plans

EPA encourages the use of multistate plans in which states would work together to achieve their respective CO_2 emission reductions.[26] In fact, the Proposed Rule indicates that EPA organized, encouraged, and attended meetings to discuss multistate planning efforts.[27] The rationale for these meetings was that, because the power sector is interconnected and electricity generated at power plants crosses state lines, states, utilities, and ratepayers might benefit from states working together to address the requirements of the rulemaking implementation. The NTAA is unaware of any Indian Tribes being invited to participate in any of these meetings. If this is the case, this would appear to contradict EPA's understanding of EGUs located on Tribal lands that would warrant the involvement of Tribes in multistate planning meeting efforts. Specifically, EPA claims that:

1. Affected EGUs located in Indian Country operate as part of the interconnected system of electricity production distribution; and
2. Operators and co-owners of these EGUs include investor-owned utilities, cooperative utilities, public power agencies, and independent power producers, most of which also co-own potentially affected EGUs within state jurisdictions.[28]

Partnership for Policy Integrity, 5 (April 2, 2014), at http://www.pfpi.net/wp-content/uploads/2014/04/PFPI-Biomass-is-the-New-Coal-April-2-2014.pdf.

[24] *See* Center for Biological Diversity, et al. v. EPA, No. 11-1101 (July 12, 2013, D.C. Cir.).

[25] Proposed Rule at 34878.

[26] *Id.* at 34846.

[27] *Id.*

[28] *Id.* at 34854.

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Indian Tribes can be treated as states under Section 301(d) of the Clean Air Act. As such, there is no reason why EPA should not have involved them in meetings with states concerning multistate planning efforts. This relates to EPA's responsibility to consult with Tribes on a government-to-government basis, something that it failed to do in this specific case. This lack of consultation is compounded by the EPA's request for comments under the Proposed Rule as to whether a Tribe wishing to develop and implement a plan, much like a state, should have the option of including the EGUs located in its areas of Indian Country in a multi-jurisdictional plan with one or more states.[29]

Further, the Proposed Rule indicates that for many states, their renewable portfolio standards allow energy generated by qualifying renewable energy sources in other states to count toward meeting such renewable portfolio standards. The NTAA finds that this same opportunity should apply to Indian Tribes that could sell renewable energy generated on their lands to help neighboring states meet their CO_2 emission reduction requirements while the Tribes could use the money from such sales to reinvest into their own economies. However, the NTAA is unaware of any discussions about this potential opportunity for Tribes and states that occurred as part of the multistate planning meetings, or individually between a Tribe and EPA. The NTAA recommends that EPA engage Tribes in a discussion about this opportunity and how it might fit under the Proposed Rule.

Finally, the NTAA fails to understand that in EPA's promotion of a multistate planning approach under the Proposed Rule, it did not work through the five regional planning organizations (RPOs)[30] which EPA has supported financially in the past. The RPOs have an established framework and governance, established relationships between states and Tribes, and a proven track record of using their combined technical, policy, and legal resources and expertise to address air quality issues effectively on a local, regional, and national level. The NTAA also finds that in some of the RPOs, there is a particularly high understanding and respect among state and federal partners about Tribal cultural values and practices, which would help in implementing the Proposed Rule across state and Tribal borders. As such, the NTAA recommends strongly that EPA provided sufficient funding to and work closely with the existing RPOs to help implement the Proposed Rule properly and effectively.

Cap-and-Trade Programs

State and Multistate. The Proposed Rule provides as one strategy a cap-and-trade program for reducing CO_2 emissions among EGUs.[31] A number of similar programs exist on a national and regional basis.[32] The NTAA understands CO_2 is a global pollutant whose emissions from individual EGUs don't necessarily have an impact locally. However, the NTAA has concerns that cap-and-trade programs adopted by states or multiple states in support of the Proposed Rule could cause co-pollutant hotspots around and near individual EGUs.

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[29] Proposed Rule at 34854.

[30] The five regional planning organizations are the Western Regional Air Partnership, Central Regional Air Planning Association, Midwest Regional Planning Organization, Visibility Improvement State and Tribal Association of the Southeast, and Mid-Atlantic/Northeast Visibility Union. *See* "Regional Planning Organization," at http://www.epa.gov/visibility/regional.html (last visited on September 10, 2014).

[31] Proposed Rule at 34881-83.

[32] *Id.* at 34848.

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The Proposed Rule indicates that some EGUs can reduce emissions at lower costs than others, and industry should be allowed to determine through market mechanisms which EGUs to control and which to leave uncontrolled, and which EGUs to potentially operate more and which to potentially operate less.[33] This type of scenario would exist under cap-and-trade programs. The NTAA expects that states involved in such programs would include the availability of allowances and offsets for EGUs. Allowances permit an individual EGU to emit pollutants at a specified level, whereas offsets are substituted for allowances. If an individual EGU was unable to meet its emissions budget, it would be able to purchase allowances on the open market, or offsets (*e.g.,* carbon sinks such as the planting or preservation of a forest), in order to allow the EGU to emit at historic or even higher emission levels. Essentially, the individual EGU could buy its way out of compliance by acquiring more allowances or offsets.

The NTAA understands that the Proposed Rule will help reduce the overall CO_2 and co-pollutant emissions of existing EGUs. However, the NTAA is concerned about the existence of local impacts or hotspots by which the owners of multiple EGUs could decide to increase the CO_2 emissions at some of their EGUs at the expense of reducing emissions at their other EGUs, particularly those emitting CO_2 at significantly high levels. Under such circumstances, the EGUs could potentially emit at historic or even higher levels which, in turn, would cause the co-pollutants of such EGUs to remain the same or increase to the detriment of local populations such as Tribes. As such, the NTAA makes the following recommendations regarding any cap-and-trade programs included under an approvable state implementation plan by EPA:

1. Restrict allowance allocations and offsets for individual EGUs having the worst health impacts on nearby communities due to their co-pollutants; and
2. Integrate controls into the state implementation plan approval process that insures emission reductions from EGUs, particularly those of co-pollutants, are actually happening near Tribal lands.

National. EPA seeks comment on development of a model rule for an interstate emissions credit trading program.[34] The NTAA limits it comments to recommending establishment of a Tribal set-aside as part of an interstate emissions credit trading program and modeled after a similar set-aside that grew out of the Western Regional Air Partnership (WRAP).

As part of an annex to the Regional Haze Rule (Annex) that was adopted in the late 1990s, an annual SO_2 tribal set-aside of 20,000 tons was made available to Indian Tribes within a nine-state region regardless if such Tribes had major industrial sources emitting SO_2.[35] This set-aside grew out of multiple discussions among the WRAP's partners and participants where issues of equity and economic development kept coming up during conversations with respect to Tribes that had hardly contributed to visibility impairment in the West but whose environment

[33] *Id.* at 34880.
[34] *Id.* at 34847-48.
[35] *See* Proposed Revisions to Regional Haze Rule, 67 Fed. Reg. 30438 (May 6, 2002). A distribution mechanism wasn't contained in the Annex, although discussion within the WRAP's Tribal Caucus understood it to be distributed to Tribes for such purposes as economic development, environmental protection, and allowances for Tribal EGUs.

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and health had been adversely affected by neighboring jurisdictions with sources emitting significant SO_2 amounts. As such, the Annex provided that the Tribal set-aside was "intended to help ensure equitable treatment for tribal economies and prevent barriers to economic development."[36] The same rationale for a Tribal set-aside exists today and should be incorporated into any national trading program that grows out of the Proposed Rule.

Environmental Justice

Executive Order (EO) 12898 establishes federal executive policy on environmental justice.[37] Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies and activities on minority populations and low-income populations in the U.S.[38] The Proposed Rule must fulfill the intent of EO 12898 whose Section 6-606 provides that the EO applies to Native American programs.[39]

The Proposed Rule indicates that there will likely be local communities affected by relatively higher concentrations of pollutants (*e.g.,* co-pollutants) during various time of the year than what would occur in absence of the Proposed Rule.[40] Further, the NTAA finds that each state will focus on the building block or blocks most important to its existing circumstances. For example, some states will focus on Building Block 4 by improving demand-side efficiencies, and other states may focus on Building Block 3, by raising their renewable portfolio standards, and still other states may focus on a combination of the building blocks, all to comply with the CO_2 emissions to which they are limited to under the Proposed Rule.

EPA has indicated that it cannot predict with accuracy how CO_2 emissions from specific EGUs would change as an outcome of the Proposed Rule due to state-led implementation and therefore cannot determine whether there would be disproportionately high and adverse human health or environmental effects on Indigenous populations from the rule.[41] By extension, the NTAA assumes that EPA cannot determine the effects of building block measures used by states, in isolation and in combination with others, on Indian Tribes. However, understanding the effect of individual EGUs on Tribes as well as the building blocks used under state programs is critical. As such, the NTAA recommends that EPA conduct a thorough environmental justice analysis of the Proposed Rule and its impacts to nearby Tribes and make it a required part of the planning process for state implementation plans.

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[36] *Id.*
[37] Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations (February 11, 1994), at http://portal.hud.gov/hudportal/HUD?src=/program_offices/fair_housing_equal_opp/FHLaws/EXO12898 (last visited on August 29, 2014).
[38] Proposed Rule at 34949.
[39] Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations (February 11, 1994), at http://portal.hud.gov/hudportal/HUD?src=/program_offices/fair_housing_equal_opp/FHLaws/EXO12898 (last visited on August 29, 2014).
[40] Proposed Rule at 34950.
[41] *Id.*

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Tribal Consultation

EPA provides that the Proposed Rule does "not have tribal implications as specified in Executive Order 13175."[42] The rationale for EPA's finding is that the Proposed Rule "would not impose substantial direct compliance costs on tribal governments that have affected EGUs located in their area of Indian country."[43] The NTAA finds that EPA does not understand fully the intent behind EO 13175 as it is not limited to federal actions with financial impacts to Tribes. Specifically, section 1(a) of EO 13175 defines "policies that have tribal implications" as:

> [R]egulations, legislative comments or proposed legislation, and other policy statements or actions that have substantial direct effects on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.[44]

The definition makes no reference to direct compliance costs on Tribal governments although such costs are one of many implications that a federal agency action could have on Tribes.

The NTAA finds that Proposed Rule has implications to Tribes beyond those identified by EPA. Some of these have already been identified by the NTAA under the Multistate Plans and Environmental Justice sections of our organization's comments, but other implications to Tribes could exist such as potential effects on Tribal treaty rights. EO 13175 requires EPA to develop an accountability process to ensure "meaningful and timely input by development of regulatory policies that have tribal implications." EPA accomplished this on a number of levels as identified in the Proposed Rule,[45] but more needs to be done by EPA to fulfill the intent of EO 13175.

The Proposed Rule states that "EPA intends to publish a supplemental proposal to establish emission performance goals (if it determines that such action is necessary or appropriate) covering the four potentially affected power plants[46]" in Indian Country: "The South Point Energy Center, on Fort Mojave tribal lands within Arizona; the Navajo Generating Station, on Navajo tribal lands within Arizona; the Four Corners Power Plant, on Navajo tribal lands within New Mexico; and the Bonanza Power Plant, on Ute tribal lands within Utah". NTAA acknowledges EPA's effort to work directly with Tribes in this capacity on matters pertaining to new regulations, and the NTAA plans to review the supplemental proposal once it is released for public comment.

Conclusion

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[42] *Id.* at 34948.
[43] *Id.*
[44] Executive Order 13175, Consultation and Coordination with Indian Tribal Governments (November 9, 2000), at http://www.epa.gov/fedrgstr/eo/eo13175.htm (last visited on August 29, 2014).
[45] Proposed Rule at 34948.
[46] *Id. At 34854.*

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In summary, the NTAA is pleased to provide the aforementioned comments and recommendations concerning the Proposed Rule.

On Behalf of the NTAA Executive Committee,

Bill Thompson, Chairman, NTAA

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From:	Hayes, Kristin
To:	Hayes, Kristin
CC:	Sharp, Phil; Burtraw, Dallas; Richardson, Nathan; Kopp, Ray; Mares, Jan
Sent:	10/29/2013 2:52:36 PM
Subject:	RFF 111(d) workshop - thank you and presentations
Attachments:	Burtraw_RFF 111d Workshop Oct 28 2013.pdf; Lashof_RFF 111d Workshop Oct 28 2013.pdf; Richardson_RFF 111d Workshop Oct 28 2013.pdf; Wyman_RFF 111d Workshop Oct 28 2013.pdf

Dear all,

On behalf of Resources for the Future, I want to thank you for taking part in yesterday's very thoughtful and robust conversation around carbon regulation for existing sources under Section 111(d) of the Clean Air Act. A special thanks to those who traveled in from all corners of the country to attend – the combination of perspectives and suggestions made the event particularly valuable.

Several attendees requested copies of the day's presentations, which I've attached here (in PDF format). If you need any further information, please don't hesitate to ask.

RFF will continue its research on these important issues over the next months and years; in the meantime, please feel free to explore RFF's existing body of work on the Clean Air Act. We look forward to staying in touch with all of you, and thanks again.

Best wishes,
Kristin Hayes

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Greenhouse Gas Regulation at Existing Power Plants under the Clean Air Act:

Decision Points for EPA and the States

Dallas Burtraw

October 28, 2013

RESOURCES FOR THE FUTURE

Useful Findings: (1) The Economic Perspective

- CAA regulations could be stringent
  - An emissions rate performance standard (tons/MWh) can achieve as many emissions reductions as cap and trade
- CAA regulations could be cost effective
  - A flexible approach (e.g. emissions rate averaging) can be efficient within the set of regulated sources
- A flexible emissions rate performance standard would result in a small change in electricity price
- This approach is not new

RFF

Useful Findings: (2) Program Design

- An emissions rate performance standard has two key features:
  - Is standard the same across units, or differentiated?
  - Can you average (trade), and with whom?
- States may want to implement an alternative design
  - Some states already have cap and trade
  - Many environmental advocates and some states and companies want to credit investments in renewables, transmission line upgrades or energy efficiency
- These policies will reduce emissions (tons) but have a different effect on emissions rates (tons/MWh)

RFF

Decision Points: Timing

1. What is the schedule for EPA guidelines (proposed & final), state implementation plans, and compliance? [Decided]
   - Draft guidelines from EPA (June 2014)
   - Final guidelines from EPA (June 2015)
   - State plans due (June 2016)

RFF

Scope

2. Will there be separate categories by fuel (oil, coal, lignite, gas) and/or technology (boiler types), or a single category for all fossil?
3. Will all categories/subcategories have the same standard?
4. Will any units or utility systems be exempted on the basis of size?
5. When will new sources be included in the existing source program?

RFF

Structure

6. What technical justification for the standard is offered?
7. Will EPA measure progress/equivalency in mass (tons) or rate (tons/MWh) terms?
   - Other criteria are also relevant
8. How stringent will the standard(s) be?

RFF

Flexibility

9. How will flexibility be built into the system? (i.e. what is the *best system of emissions reduction*?)
10. How will the benefits of flexibility be divided between cost savings for firms and greater environmental stringency?
11. Will the guidelines enable fuel switching from coal to gas as a compliance option?
12. How will biomass and/or natural gas cofiring at coal facilities be credited?
13. Can measures taken *outside the fence line* of the regulated source category (renewables, demand-side efficiency, transmission upgrades) be credited?

RFF

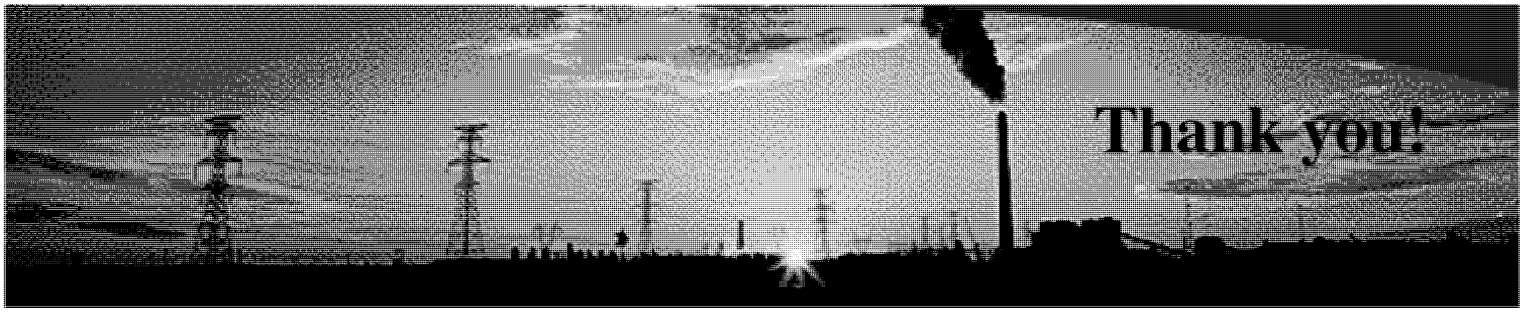
Federalism

14. How much guidance will EPA provide to states? A model rule? Methods to demonstrate equivalency of different approaches?
15. What criteria can/must states consider? Emissions/emissions rates, cost, other environmental benefits, “remaining useful life” of sources, etc.?
16. What is the baseline? How will actions already taken be considered?

RFF

Three exceptional characteristics of section 111(d)

1. Multiple evaluation criteria are relevant:
   emissions rates, emissions, cost effectiveness, environment benefits

2. State-based process expected

3. ***Best system of emissions reduction*** implies flexibility