APPENDIX Q

Impact of Wintertime SCR/SNCR Optimization on Visibility Impairing Nitrate Precursor Emissions

MANE-VU Technical Support Committee
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MANE - VU
Mid-Atlantic/Northeast Visibility Union

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Executive Summary

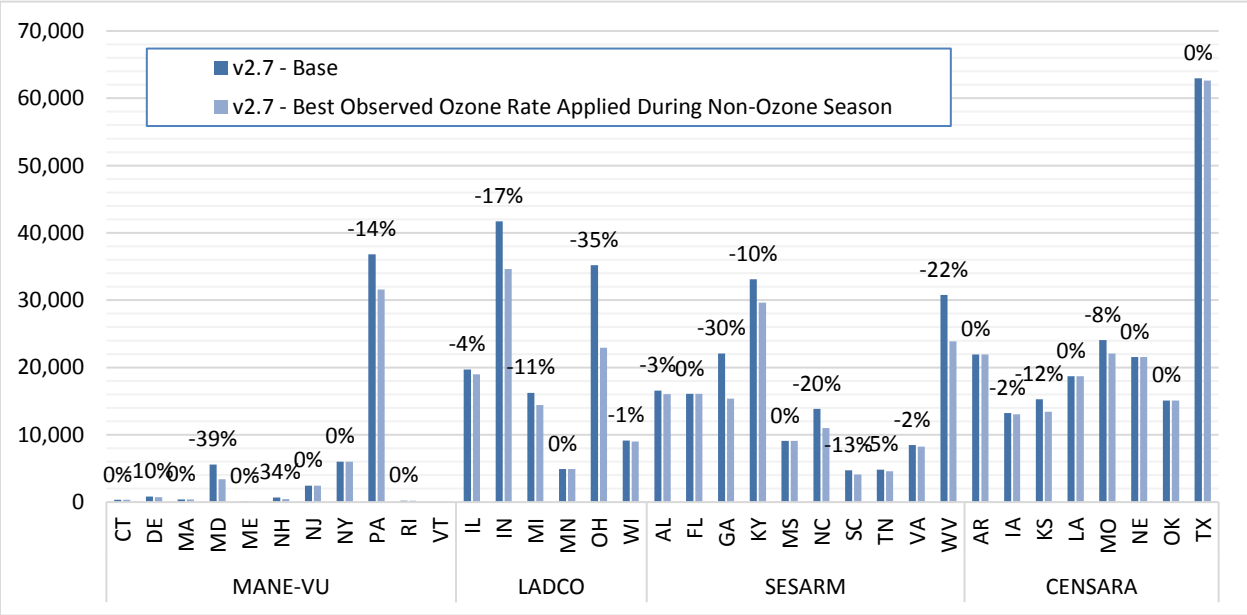
During the first planning phase for regional haze, programs that were put in place focused on reducing sulfur dioxide (SO_2) emissions. The reductions achieved led to improvements in visibility at the MANE-VU Federal Class I Areas due to reduced sulfates formed from SO_2 emissions. The reduction in visibility impairment from sulfates resulted in nitrates driving the visibility impairment rather than sulfates in some MANE-VU Class I Areas on the 20% most impaired days, in particular, during the winter months. Nitrogen oxide (NO_X) emissions are an important precursor to the formation of nitrates.

Often Electric Generating Units (EGUs) only run NO_X emission controls to comply with ozone season trading programs; consequently, emissions of NO_X are uncontrolled during the winter. Controlling winter-time NO_X emissions at EGUs using existing controls is generally more cost-effective compared to other sectors that would have to install and bear the capital costs of control equipment solely for improving visibility.

We looked at the visibility data and observed emission rates from EGUs with installed selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) controls, and compared those rates to projected emissions using the ERTAC EGU tool, to show the potential NO_X emissions reductions from running existing SCR and SNCR during the winter months.

We found that the number of most impaired days occurring during the winter is increasing at all Class I areas, in particular Brigantine, and that Brigantine and Lye Brook are seeing nitrate impairment in high levels during those times. We also found that back trajectories from those sites during the winter often traverse MANE-VU and LADCO states with power plant emissions. We found that running existing installed controls is one of the most cost-effective ways to control NO_X emissions from EGUs and that running existing SCRs and SNCRs on EGUs could substantially reduce the NO_X emissions in many of the states upwind of Class I areas in MANE-VU that lead to visibility impairment during the winter from nitrates.

Total 2028 Projected NO_X Emissions from January 1-April 30 and November 1-December 31



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Introduction

During the first planning phase for regional haze, programs that were put in place focused on reducing sulfur dioxide (SO_2) emissions. The reductions achieved led to improvements in visibility at the MANE-VU Federal Class I Areas due to reduced sulfates formed from SO_2 emissions. The reduction in visibility impairment from sulfates resulted in nitrates driving the visibility impairment rather than sulfates in some MANE-VU Class I Areas on the 20% most impaired days, in particular, during the winter months. Nitrogen oxide (NO_X) emissions are an important precursor to the formation of nitrates.

Despite the progress made in the first planning period, additional progress is needed to continue to improve visibility. While many hazy days continue to be affected by high sulfate concentrations, many of the most impaired days are now dominated by nitrates, particularly on cooler days, when nitrogen emissions are more likely to contribute to the formation of nitrates rather than participating in the formation of ozone. Therefore, in addition to maintaining reductions already achieved, it is necessary to look closely at the sources of nitrates and the effectiveness of potential controls.

Often Electric Generating Units (EGUs) only run NO_X emission controls to comply with ozone season trading programs; consequently, emissions of NO_X are uncontrolled during the winter. Controlling winter-time NO_X emissions at EGUs using existing controls is generally more cost-effective compared to other sectors that would have to install and bear the capital costs of control equipment solely for improving visibility. We will look at the visibility data and observed emission rates from EGUs with installed selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) controls, and compare those rates to projected emissions, to show the improvements that can be made to visibility impairment from running existing SCR and SNCR during the winter months.

Current Visibility Data

Figure 1 through Figure 5 show the variability in which meteorological seasons contained "20% most impaired days"[1] from 2000 to 2015. The 20% most impaired days metric was used because it aligns with the requirements for measuring progress as outlined in the Regional Haze Rule Update (82 FR 3078) and removes the impacts of natural sources of impairment, such as wild fires and sea salt, from consideration. The new metric also excludes some days that experience both high impairment from anthropogenic sulfate pollution and natural wildfires during the summer which leads to a greater focus on winter time nitrate impairment than would have occurred using the old "worst day" metric. However, the progress made in reducing SO_2 emissions and thus sulfate impairment has also lead to more impaired days being dominated by nitrates as we will see.

The Edwin B. Forsythe National Wildlife Refuge (hereafter Brigantine Wilderness) has the strongest increase in winter 20% most impaired days, followed by Acadia National Park and Great Gulf Wilderness Area. The only site that did not see an increase in the number of winter 20% most impaired days was Lye Brook, but this is likely due to the fact that the Lye Brook IMPROVE monitor was moved in 2012 and the 20% most impaired days were not calculated as of this writing for the new site. When you look at 20% most impaired days you also see an upward trend in the number of winter days. This shows that

[1] 20% most impaired days are based on the draft IMPROVE AEROSOL, RHR III methodology used to calculate visibility impairment available in the Federal Land Manager Environmental Database (FED) database as of June 8, 2017 in accordance with the new definitions of impairment in regional haze regulatory framework

emissions that affect visibility during colder months are important to consider when developing control strategies, particularly for Brigantine.

Figure 1: Trends in seasonality of 20% most impaired days at Acadia National Park

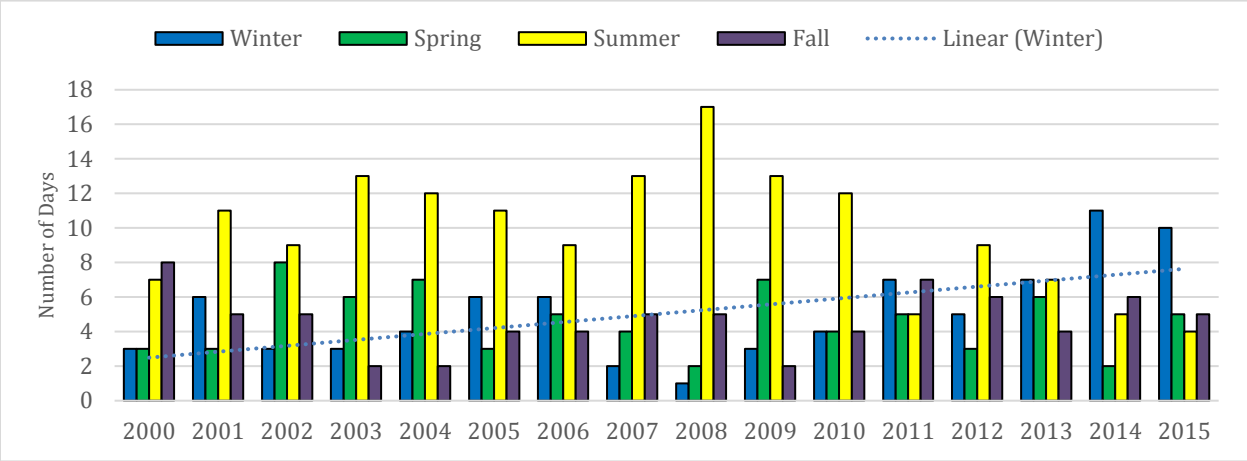


Figure 2: Trends in seasonality of 20% most impaired days at Moosehorn NWR

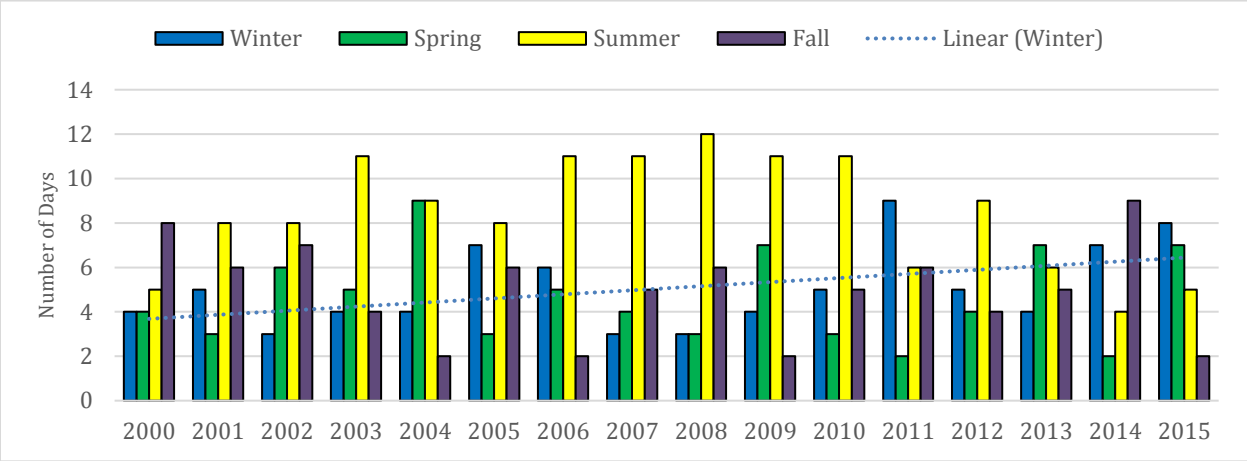


Figure 3: Trends in seasonality of 20% most impaired days at Lye Brook Wilderness

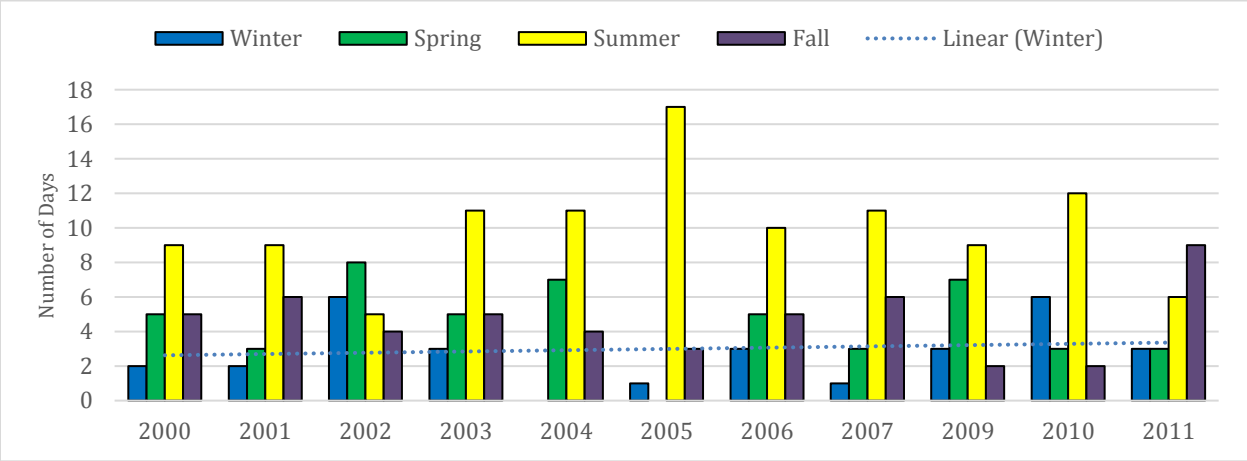


Figure 4: Trends in seasonality of 20% most impaired days at Great Gulf Wilderness

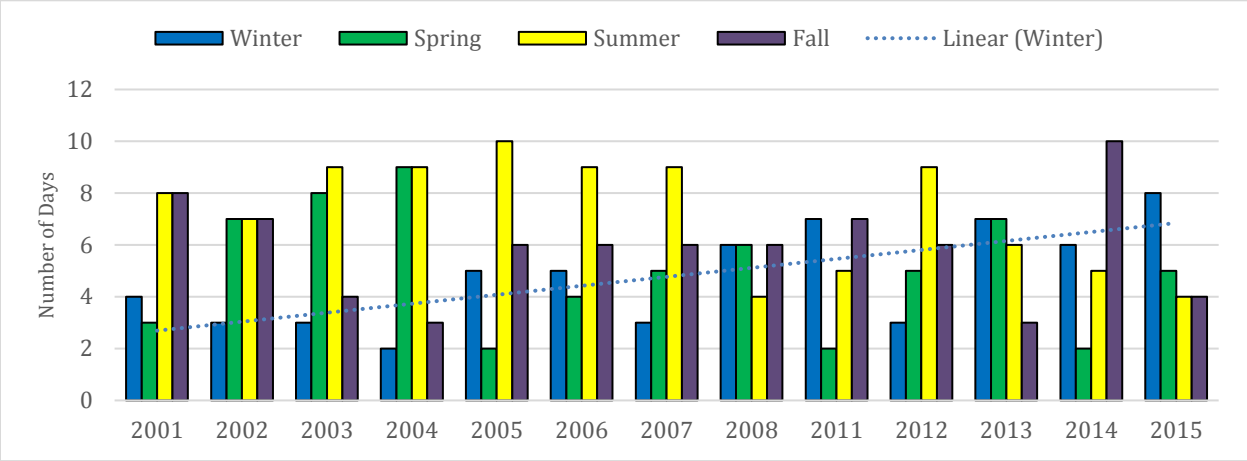
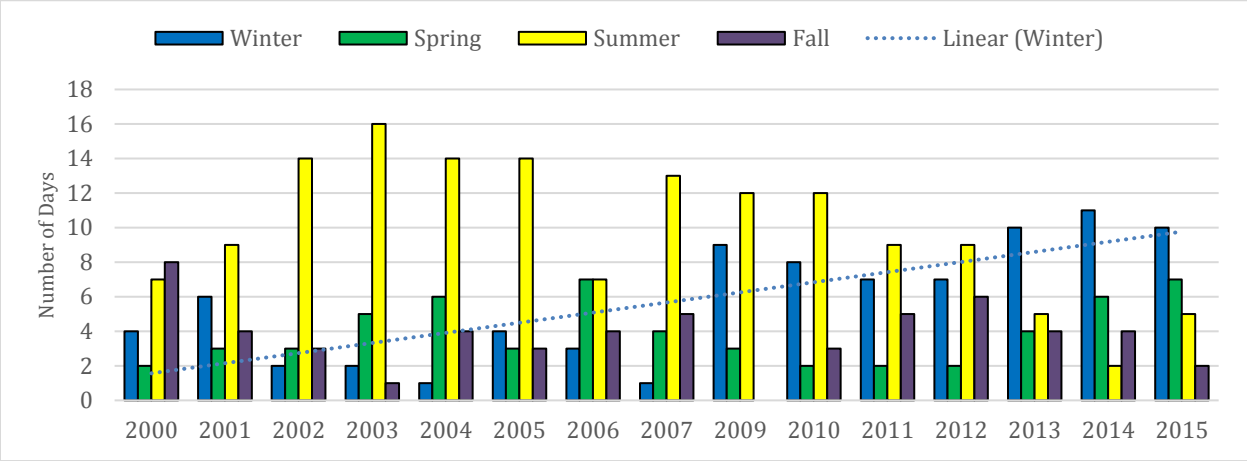


Figure 5: Trends in seasonality of 20% most impaired days at Brigantine Wilderness



Class I area plots were also created showing light extinction speciation for each day for 2002, 2011, and 2015 (Figure 6 through Figure 10). For all the Class I areas, there is a significant decrease in light extinction from 2002 to 2011 (especially from sulfates contribution) and a smaller decrease from 2011 to 2015. At Lye Brook and Brigantine, nitrates contribute to a greater percentage of visibility impairment on certain days.

Figure 6: Acadia National Park 2002/2011/2015 Speciation Comparison

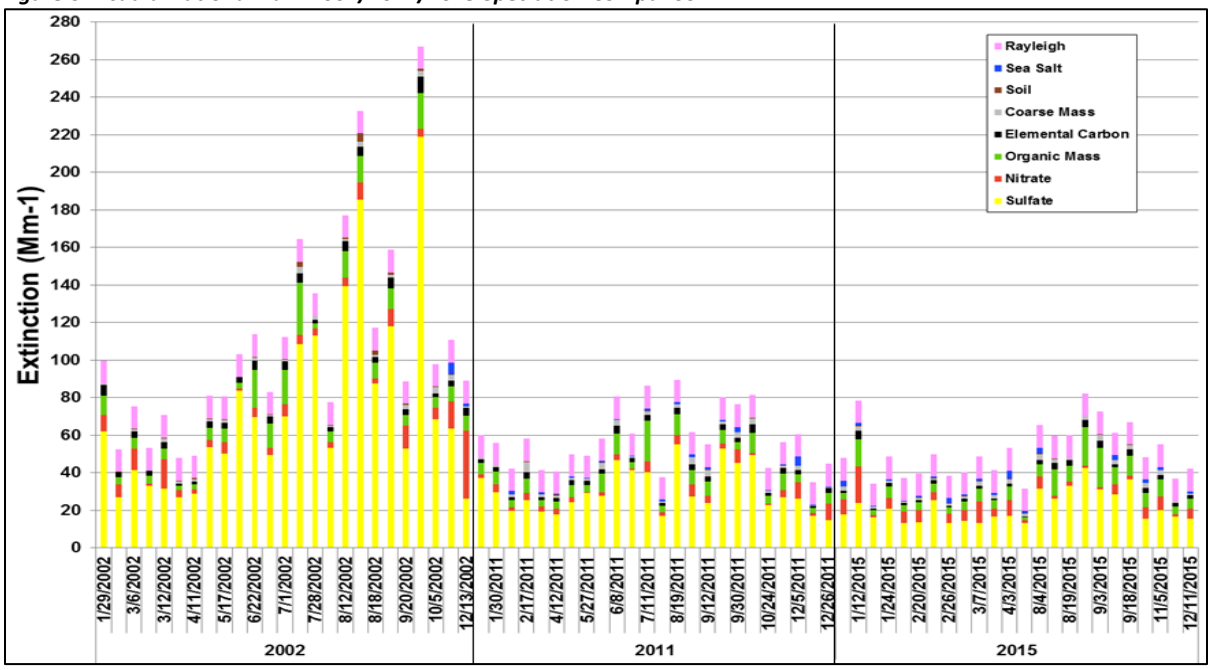


Figure 7: Moosehorn Wilderness 2002/2011/2015 Speciation Comparison

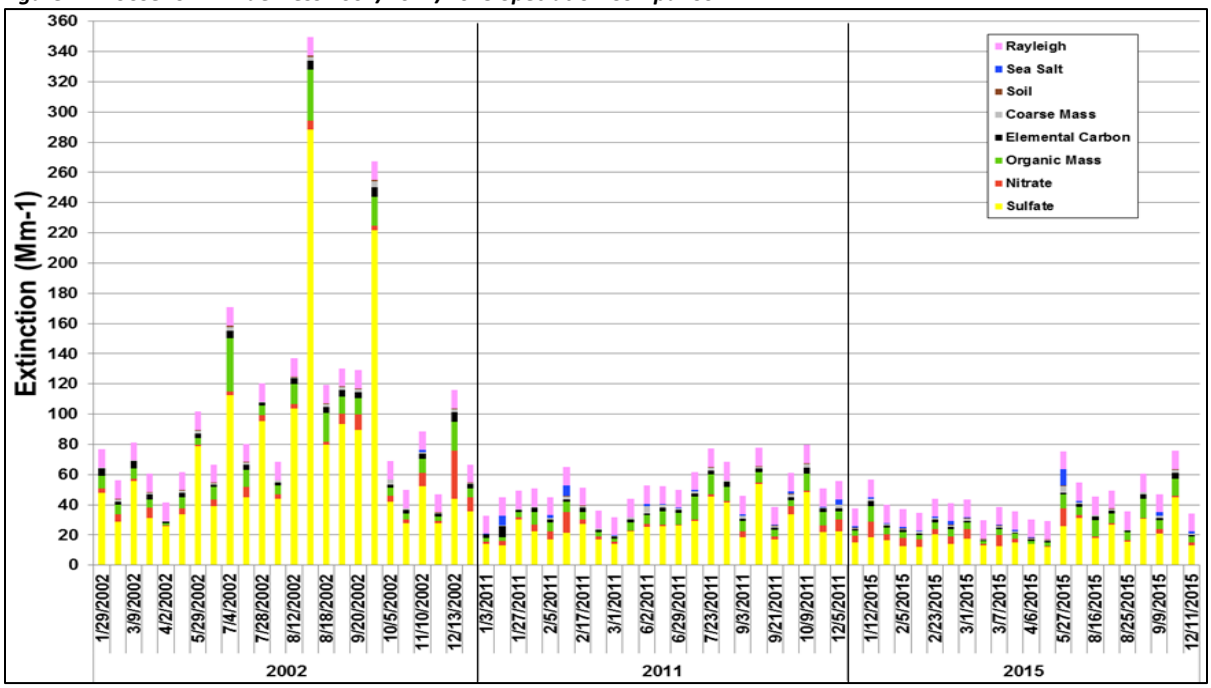


Figure 8: Great Gulf Wilderness 2002/2011/2015 Speciation Comparison

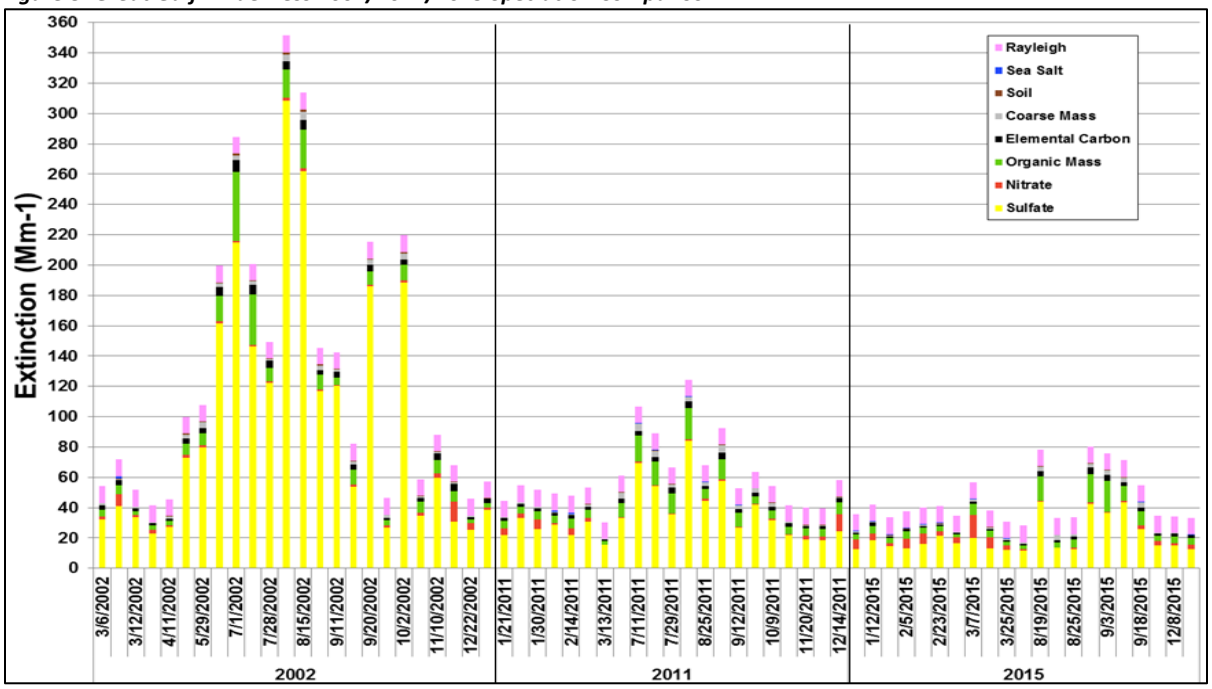


Figure 9: Lye Brook Wilderness 2011/2015 Speciation Comparison

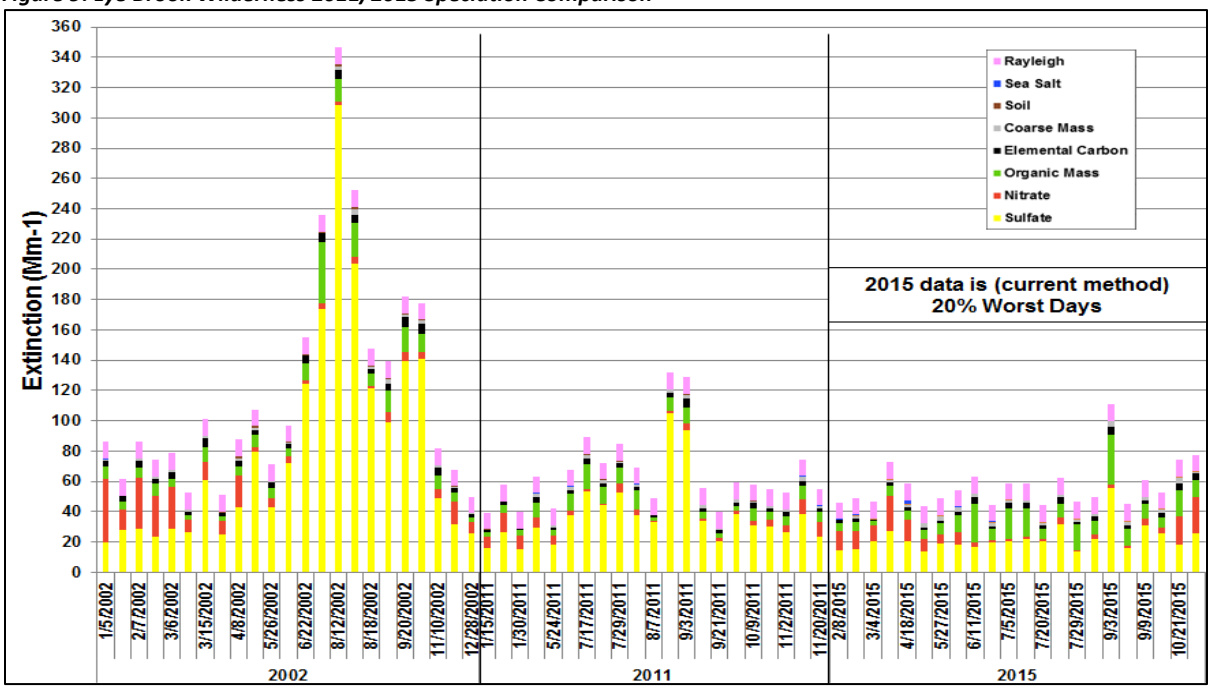


Figure 10: Brigantine Wilderness 2002/2011/2015 Speciation Comparison

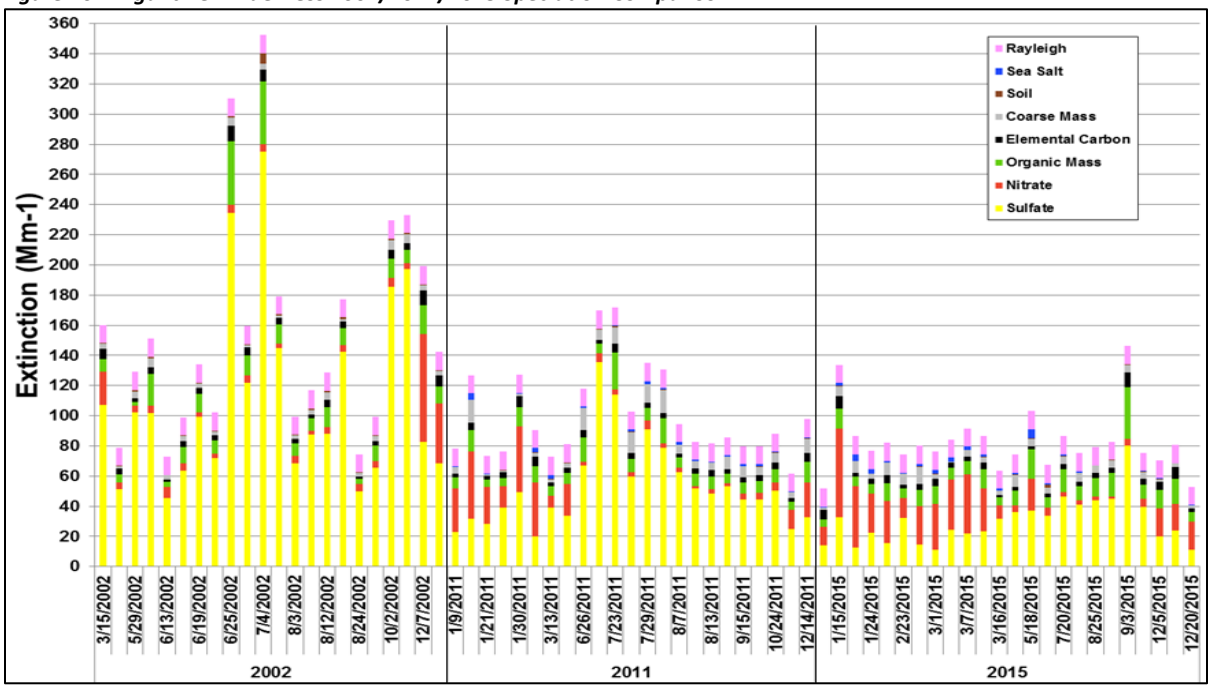


Table 1 demonstrates these trends between 2000 and 2015. At Brigantine, starting in 2007, at least half of the 20% most impaired days in each winter has had more extinction from nitrates than sulfates. In 11 winters out of 15 (73%) in the 2000-2015 period, Brigantine had days in which nitrates contributed more than sulfates to light extinction. At Lye Brook, in the same period, 6 winters (i.e., 43%) had some days in which nitrates contributed more than sulfates to light extinction, and more than half of the 20% most impaired days in 4 of these winters had more extinction from nitrates than sulfates. It is rare (less than 5%) for the other three Class I areas to have winter days where there is more extinction from nitrates than sulfates.

Focusing in on Lye Brook and Brigantine in more detail, one can see in Figure 11 and Figure 12 for Lye Brook and Figure 13 and Figure 14 for Brigantine that during the winter months the back trajectories on many of the 20% most impaired days traverse the southwestern states in MANE-VU, the states in LADCO and the northern most states in SESARM. Later we will see how this information compares with the locations of EGUs that could impact MANE-VU Class I Areas.

Table 1: Number of 20% most impaired winter days and winter days where nitrate extinction was greater than sulfate at each monitored Class I area*

Site	Year	Winter Days	NO_3 > SO_4	%	Site	Year	Winter Days	NO_3 > SO_4	%
Acadia	2000	3	0	0%	*Great Gulf*	2007	3	0	0%
	2001	6	0	0%		2008	6	0	0%
	2002	3	1	33%		2011	7	0	0%
	2003	3	0	0%		2012	3	0	0%
	2004	4	0	0%		2013	7	1	14%
	2005	6	0	0%		2014	6	0	0%
	2006	6	0	0%		2015	8	0	0%
	2007	2	0	0%	*Lye Brook*	2000	2	0	0%
	2008	1	0	0%		2001	2	1	50%
	2009	3	0	0%		2002	6	3	50%
	2010	4	0	0%		2003	3	0	0%
	2011	7	0	0%		2005	0	0	0%
	2012	5	0	0%		2006	1	0	0%
	2013	7	0	0%		2007	3	0	0%
	2014	11	1	9%		2009	1	1	100%
	2015	10	0	0%		2010	3	0	0%
Brigantine	2000	4	1	25%		2011	6	0	0%
	2001	6	1	17%		2012W	5	4	80%
	2002	2	0	0%		2013W	8	1	13%
	2003	2	1	50%		2014W	7	3	43%
	2004	1	1	100%		2015W	3	0	0%
	2005	4	0	0%	*Moosehorn*	2000	4	0	0%
	2006	3	0	0%		2001	5	0	0%
	2007	1	0	0%		2002	3	0	0%
	2009	9	3	33%		2003	4	1	25%
	2010	8	5	63%		2004	4	0	0%
	2011	7	3	43%		2005	7	0	0%
	2012	7	4	57%		2006	6	0	0%
	2013	10	5	50%		2007	3	0	0%
	2014	11	7	64%		2008	3	0	0%
	2015	10	6	60%		2009	4	0	0%
Great Gulf	2001	4	0	0%		2010	5	0	0%
	2002	3	0	0%		2011	9	0	0%
	2003	3	0	0%		2012	5	0	0%
	2004	2	0	0%		2013	4	0	0%
	2005	5	0	0%		2014	7	0	0%
	2006	5	0	0%		2015	8	0	0%

*Notes

1. Data was not available for Great Gulf in 2000, 2009, 2010, or at Lye Brook in 2004
2. The location of the Lye Brook monitor changed from 2011 to 2012, though several months of contemporaneous monitoring results were collected for both sites and the measurements were found to be comparable. Also as a result, 20% most impaired days are not available from 2012 on so 20% worst days were used for those years and are marked with a W.

Figure 11: Trajectory analyses of Lye Brook Wilderness 20% most impaired days during Winter/Spring 2011

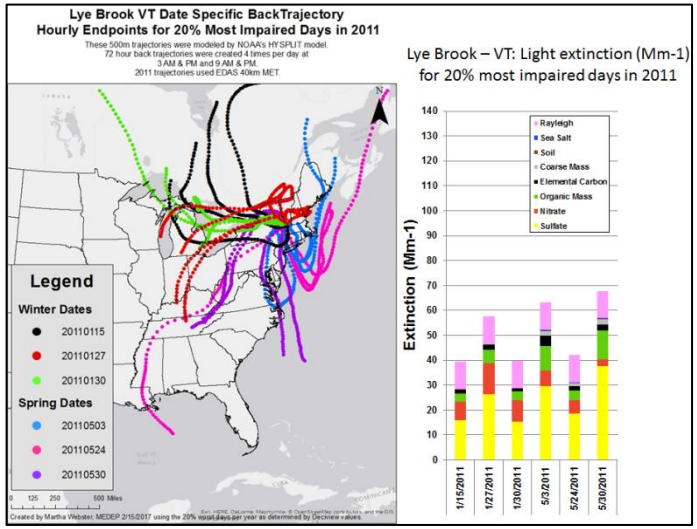


Figure 12: Trajectory analyses of Lye Brook Wilderness 20% most impaired days during Winter 2015

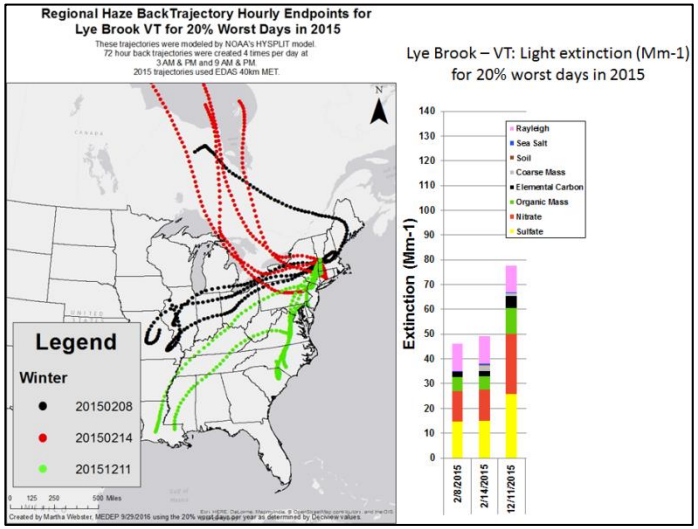


Figure 13: Trajectory analyses of Brigantine 20% most impaired days during Winter 2011

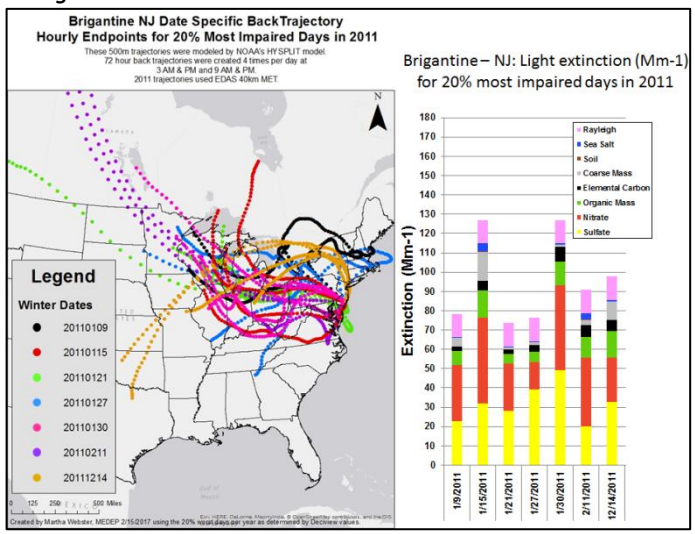


Figure 14: Trajectory analyses of Brigantine 20% most impaired days during Winter 2015

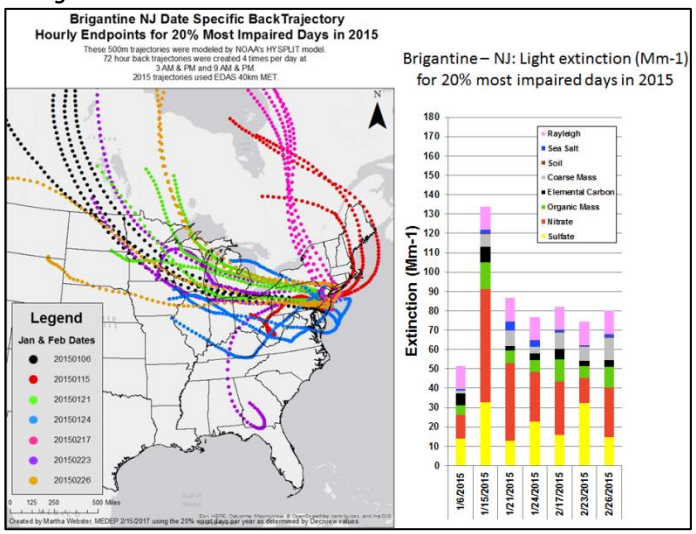
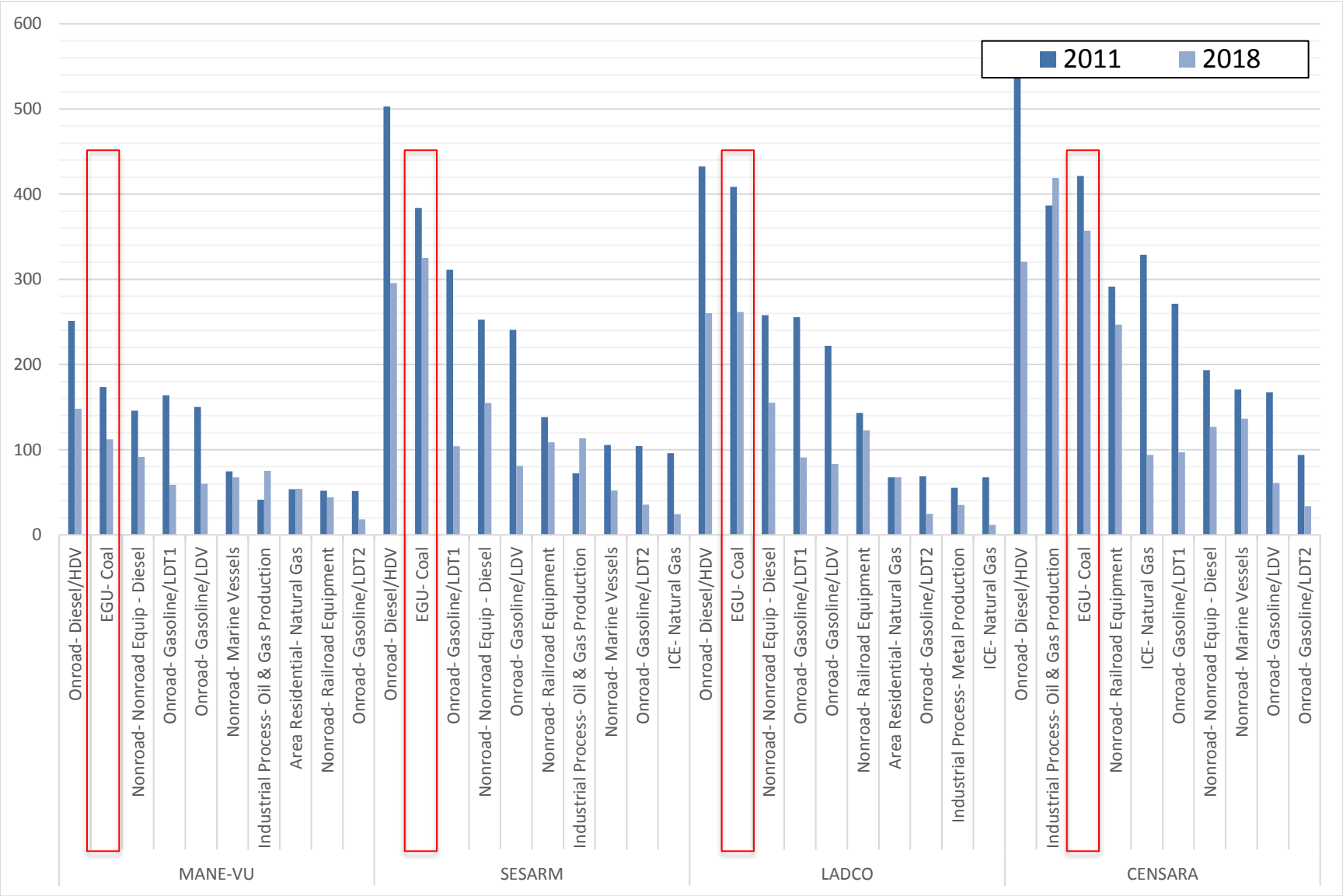


Figure 15: Sources of NO_X emissions in the Eastern United States based on 2011 and 2018 Alpha 2 inventory



Sources of Anthropogenic NO_X Emissions

Given that regulation of NO_X emission sources is typically the more cost-effective approach to reducing precursors of nitrates, the next step is to determine which sources produce the emissions that need to be reduced. When looking at the NO_X emissions inventory for both 2011 and 2018 (Figure 15) one sees that for each RPO in the Eastern United States, EGUs (highlighted) are among the top two most important NO_X–emitting source sectors.[2]

However, the focus of the analysis is not on heavy-duty vehicles or mobile sources in total, which do have a large overall contribution. As described below, the reasons for this are regulatory and scientific in nature.

First, states have very little regulatory authority to address mobile sources. The Clean Air Act under Section 209 preempts individual states outside of California from adopting emissions standards that differ from EPA's, and lower emissions standards are by far the most effective way to address NO_X emissions from mobile sources. Emissions standards for light duty vehicles were also recently lowered under the Tier 3 regulations[3] and many states in MANE-VU already have adopted the most recent California Low Emission Vehicle standards. Additionally, as of this writing, the most recent petition from the South Coast Air Quality Management District to tighten emission standards from heavy-duty vehicles, which many MANE-VU members have signed onto, has not yet been acted upon by EPA.[4]

Second, emissions from mobile and area sources are emitted close to ground level, which results in high levels of dry deposition and a lack of mixing and transport, whereas emissions from EGUs are released from tall stacks resulting in higher levels of vertical atmospheric mixing, a greater amount of pollution forming secondary organic aerosols, and more extensive pollution transport.[5,6] This implies that NO_X emissions from EGUs will likely have a wider range of impact on the formation of visibility impairing particulates in the mostly rural Class I areas in the eastern part of MANE-VU than NO_X emissions from other types of distant sources that emit at ground level, such as mobile sources. However, the exclusion of mobile sources in this analysis should not imply that locally emitted NO_X from mobile sources, particularly heavy-duty vehicles, should not be considered for analysis and control.

Third, running existing controls on EGUs has been found to be possibly the most cost effective way to control NO_X emissions. In particular, EPA found that a reasonable cost to restart an idled SCR on a coal-fired EGU would be $1,400 per ton of NO_X removed and $3,400 per ton of NO_X removed to restart an idled SNCR.[7,8] EPA found that retrofitting existing coal-fired EGUs with SCR would be $5,000 and SNCR would be $6,400 per ton of NO_X removed.[9]

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[2] Mid-Atlantic Northeast Visibility Union, "Contribution Assessment Preliminary Inventory Analysis."
[3] US EPA, "Control of Air Pollution from Motor Vehicles: Tier 3 Motor Vehicle Emission and Fuel Standards Final Rule."
[4] South Coast Air Quality Management District, "Petition to EPA for Rulemaking to Adopt Ultra-Low NOx Exhaust Emission Standards for On-Road Heavy-Duty Trucks and Engines."
[5] Fisher, "The Effect of Tall Stacks on the Long Range Transport of Air Pollutants."
[6] Trimble, "Air Quality: Information on Tall Smokestacks and Their Contribution to Interstate Transport of Air Pollution."
[7] US EPA, "EGU NOx Mitigation Strategies Final Rule TSD."
[8] Ibid.
[9] Ibid.

For all of these reasons, focusing on running controls on EGUs to reduce the impact of nitrates on visibility impairment during the colder months is the most reasonable approach that should be considered.

Emission Rate Processing

Maryland Department of the Environment conducted an ozone season analysis in order to determine the emission benefits that could be achieved if coal-fired EGUs ran their already installed NO_X controls at the best observed ozone season emission rates found by examining hourly emissions data from CAMD during the period 2005-2012.[10] Due to the fact that the primary factor in reducing the effectiveness of NO_X emission controls is flue gas temperature rather than the ambient temperature, any properly configured control system would not see a decrease in effectiveness during the winter months. Therefore, the best observed ozone season emission rates were assumed to be achievable during non-ozone season months as well. However, we determined it was not appropriate to use the best observed non-ozone season emissions rates in this analysis because the expectation was that controls would not necessarily be run to the same extent as during the ozone season since the same regulatory drivers, namely the ozone season NO_X trading programs, are not in place in the winter time.

We also compared the best observed ozone season rates that were being used in this analysis to Mode 4 NO_X emission rates from EPA's NEEDS v5.15. We found on average the 160 units analyzed had a Mode 4 NO_X emission rate that was 0.04 lb/MMBTU higher than the best observed rate being used in the analysis. While the emission rates used in this analysis are lower than the rates EPA uses they are well within the same magnitude that EPA relies on for its power sector modeling.

States have developed the ERTAC EGU projection tool[11] in order to project future year EGU emissions, and this tool is being used in development of base case 2011 and future case 2028 EGU emissions inventories for regional haze planning. The direct reliance of the ERTAC EGU projection tool on base year hourly data in developing future year hourly projections maintains changes in peak operations that could occur during the summer or winter, as well as downtime for maintenance activities or malfunctions.

In order to comply with the Mercury Air Toxic Standard (MATS) some units have opted to run SCR with less ammonia in order to remove mercury from the exhaust emissions. We also evaluated whether there could be an issue with best observed ozone season rates being applied inappropriately to such units. 41 of the 160 units considered had mercury controls installed, leaving 119 units that could be potentially using the appropriate rates. 15 of those units had SNCR, which is not used to remove mercury, leaving 104 units. 15 of the remaining units had their best observed ozone season rate in 2014 or 2015, which would imply that if they were using the SCR in such a fashion they are still achieving NO_X reductions. The remaining 89 units had a Mode 4 NOX emission rate that was on average 0.05 lb/MMbtu higher than the best observed rate implying that EPA does not expect the other units to be

[10] Vinciguerra et al., "Expected Ozone Benefits of Reducing Nitrogen Oxide (NOx) Emissions from Coal-Fired Electricity Generating Units in the Eastern United States."
[11] AMEC, "Software Technical Documentation for Software to Estimate Future Activity and Air Emissions from Electric Generating Units (EGUs)."

using SCR controls to control mercury. This information was taken from NEEDS v5.15, which accounts for the MATS program.

One design feature of the ERTAC tool is that it won't shut down specific units permanently or even for several days unless the user specifies that the unit will behave in that manner in a given future year. This was intended since having a particular unit shutdown would result in ozone or haze benefits occurring in a particular region near to a unit that would not necessarily shutdown in that given year or hour. The error that would occur from incorrectly projecting particular units to shut down in a given hour is far worse from the perspective of air quality planning than using an optimistic emission rate when a particular unit may or may not be cycling on and off.

The version of future case regional haze modeling that is expected to be used in regional progress goal modeling is the Gamma inventory, which includes ERTAC EGU v2.7 projections for the EGU sector.

To estimate the impacts of optimizing controls during the winter, the best observed rates were processed for inclusion in the ERTAC EGU control file, and then, ERTAC EGU v2.7 was rerun with the new control file.[12] Full details of the creation of the control file and the data in the control file are found in Appendix A.

Results

NO_X emissions were projected using ERTAC and the emissions were compared for the time period from January 1 – April 30 and November 1 – December 31, the time period considered the non-ozone season. Results are being compared between the v2.7 base case results and the run where the best observed rates were applied.

We found that states in the four eastern RPOs would see a drop of NO_X emissions of ~55,000 tons (10%) when best observed rates were applied during non-ozone season i.e., which is approximately 307 tons per day respectively. Full state level data for the three scenarios are written out in Table 2 and depicted visually in Figure 16.

Table 2: Total 2028 Projected NO_X Emissions from January 1-April 30 and November 1-December 31

RPO	State	Base (Tons)	Non-OS Best Observed Rate Run (Tons)	% Change
MANE-VU	CT	327.03	327.03	0%
	DE	810.58	728.16	-10%
	MA	390.98	390.98	0%
	MD	5,563.30	3,388.78	-39%
	ME	133.37	133.37	0%
	NH	690.11	455.99	-34%
	NJ	2,463.72	2,463.72	0%
	NY	6,007.40	6,007.40	0%
	PA	36,794.01	31,570.49	-14%
	RI	201.99	201.99	0%
	VT	0.00	0.00	n/a
		53,382.49	**45,667.91**	-14%
LADCO	IL	19,718.14	18,992.34	-4%
	IN	41,709.04	34,635.87	-17%

[12] All versions of the inputs were processed using v1.01 of the ERTAC EGU code.

RPO	State	Base (Tons)	Non-OS Best Observed Rate Run (Tons)	% Change
	MI	16,240.10	14,444.21	-11%
	MN	4,915.55	4,915.55	0%
	OH	35,210.31	22,931.80	-35%
	WI	9,129.28	9,024.42	-1%
		126,922.43	**104,944.19**	-17%
SESARM	AL	16,556.30	16,042.83	-3%
	FL	16,071.02	16,071.02	0%
	GA	22,085.39	15,355.41	-30%
	KY	33,095.90	29,643.16	-10%
	MS	9,099.17	9,099.17	0%
	NC	13,830.92	11,012.51	-20%
	SC	4,744.46	4,126.18	-13%
	TN	4,797.96	4,576.16	-5%
	VA	8,457.73	8,249.79	-2%
	WV	30,770.17	23,886.70	-22%
		159,509.02	**138,062.93**	-13%
CENSARA	AR	21,917.97	21,917.97	0%
	IA	13,249.45	13,038.43	-2%
	KS	15,293.89	13,405.27	-12%
	LA	18,714.47	18,714.47	0%
	MO	24,068.10	22,090.33	-8%
	NE	21,554.27	21,554.27	0%
	OK	15,081.12	15,081.12	0%
	TX	62,943.01	62,633.23	0%
		192,822.28	**188,435.10**	-2%
Grand Total		**532,636.21**	**477,110.12**	-10%

Figure 16: Total 2028 Projected NO_X Emissions from January 1-April 30 and November 1-December 31

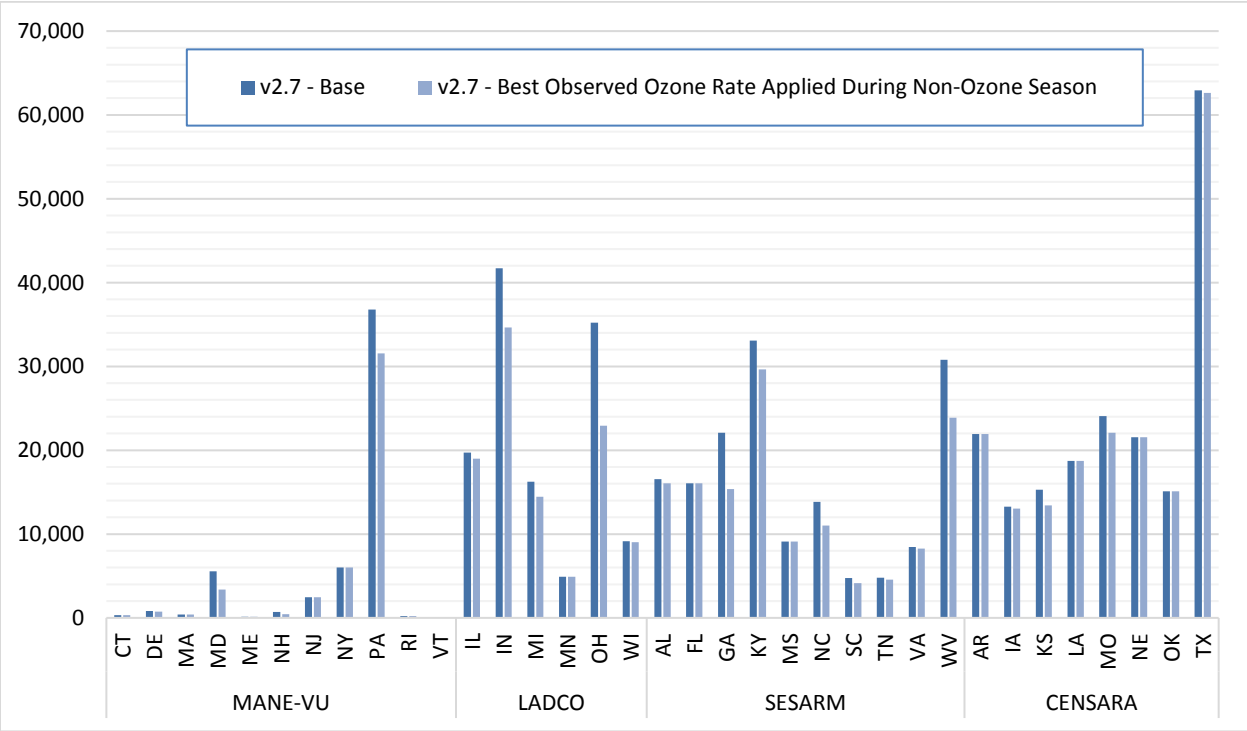
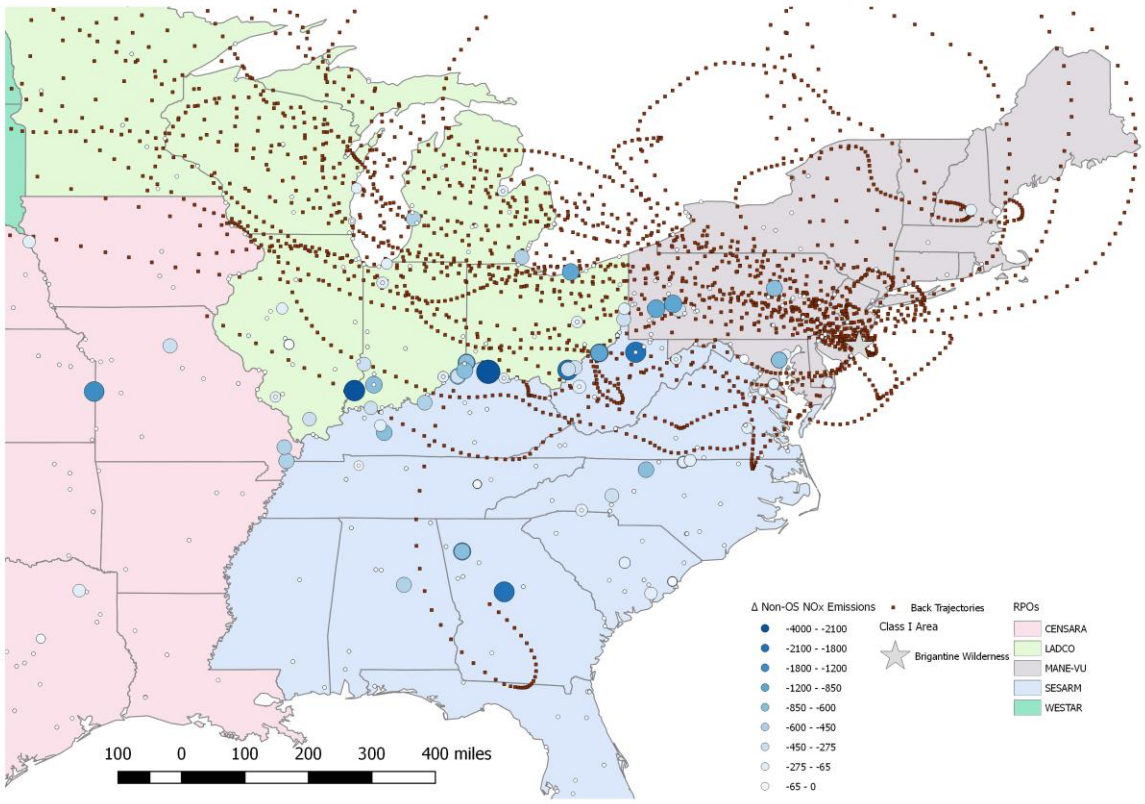


Figure 17 shows the change in non-ozone season emissions that occur when best observed rates are used during the non-ozone season months. It also shows which back trajectories occurred on days where nitrate impairment outweighs the sulfate impairment at Brigantine. Many of the back trajectories on the 20% most impaired days traverse the locations of the EGUs that are seeing some of the greatest reductions in emissions in the analysis. You can clearly see emission reductions occurring at power plants in Pennsylvania, Michigan, and along the Ohio River valley. Since the emissions from these power plants are released into air masses that are likely to travel to Brigantine, these emissions reductions should have a significant benefit at Brigantine. One should note that the back trajectories were not run at an elevation intended to evaluate against mobile and area sources and were not run for a long enough time period to demonstrate impacts from further away states such as Texas. The complete list of sources is provided in Appendix B.

Figure 17: Change in non-OS NO_X emissions (tons) due to optimization of non-OS emission rates and 2011 and 2015 back trajectories on 20% most impaired winter days where nitrates impacted visibility more than sulfates at Brigantine Wilderness



Summary

In recent years several MANE-VU Class I Areas have seen an increase in the relative visibility impairment from nitrates during the colder months. NO_X emissions are one of the main anthropogenic precursors to wintertime nitrate formation. Due to the higher elevation at which EGUs release emissions, NO_X emissions from EGUs have more potential to impact distant Class I Areas than other types of NO_X emission sources. Running existing installed controls is considered to be one of the most cost-effective ways to control NO_X emissions from EGUs. The analysis presented in this report demonstrates that running existing SCRs and SNCRs on EGUs would substantially reduce the NO_X emissions that lead to visibility impairment during the winter from nitrates.

Appendix A

In order to create the control file, the annual summary file and preprocessed control file files from the ERTAC v2.7and the best observed rate file were imported into Microsoft Access. The preprocessed control file was used since it included already processed seasonal controls, which are in a separate input file. Then, the best ozone season NO_X emission rate was compared to the non-ozone season NO_X emission rate from the annual summary file. In cases where the best observed ozone season NO_X emission rate at a unit with an installed SCR or SNCR was lower than the non-ozone season NO_X emission rate found in the annual summary an emission rate entry was added to the control file reflecting the best observed rate. Entries in the existing control emissions file for NO_X emissions for units that met the criteria were removed (156 entries) and then new NO_X emission rates were appended (291 entries). It should be noted that not all units have a control file entry since many units rely on the base year emission rates solely in ERTAC. The replacement ertac_control_emissions.csv file was then run through ERTAC EGU, using all other inputs directly from the 2028 projections for ERTAC v2.7, except ertac_seasonal_controls.csv, which was not needed for the run due to its inclusion in ertac_control_emissions.csv. The entries added to the final control file are in Table 3 below.

Table 3: Entries added to ERTAC Control File

ORISPL Code	Unit ID	Factor Start Date	Factor End Date	Pollutant	Emission Rate	Con. Eff.	Best Observed Rate Year
1241	1	2028-01-01	2028-04-30	NOX	0.081		2011
1241	1	2028-11-01	2028-12-31	NOX	0.081		2011
1241	2	2028-01-01	2028-04-30	NOX	0.0908		2015
1241	2	2028-11-01	2028-12-31	NOX	0.0908		2015
1356	1	2028-01-01	2028-04-30	NOX	0.0448		2005
1356	1	2028-11-01	2028-12-31	NOX	0.0448		2005
1356	3	2028-01-01	2028-04-30	NOX	0.0272		2005
1356	3	2028-11-01	2028-12-31	NOX	0.0272		2005
1356	4	2028-01-01	2028-04-30	NOX	0.0272		2005
1356	4	2028-11-01	2028-12-31	NOX	0.0272		2005
1364	3	2028-01-01	2028-04-30	NOX	0.045		2005
1364	3	2028-11-01	2028-12-31	NOX	0.045		2005
1364	4	2028-01-01	2028-04-30	NOX	0.0374		2007
1364	4	2028-11-01	2028-12-31	NOX	0.0374		2007
1378	3	2028-01-01	2028-04-30	NOX	0.1001		2005
1378	3	2028-11-01	2028-12-31	NOX	0.1001		2005
1552	1	2028-01-01	2028-04-30	NOX	0.2783		2015
1552	1	2028-11-01	2028-12-31	NOX	0.2783		2015
1552	2	2028-01-01	2028-04-30	NOX	0.2351		2015
1552	2	2028-11-01	2028-12-31	NOX	0.2351		2015
1554	2	2028-01-01	2028-04-30	NOX	0.2222		2015
1554	2	2028-11-01	2028-12-31	NOX	0.2222		2015
1554	3	2028-01-01	2028-04-30	NOX	0.0552		2015
1554	3	2028-11-01	2028-12-31	NOX	0.0552		2015
1571	1	2028-01-01	2028-04-30	NOX	0.104		2014
1571	1	2028-11-01	2028-12-31	NOX	0.104		2014
1571	2	2028-01-01	2028-04-30	NOX	0.1927		2009
1571	2	2028-11-01	2028-12-31	NOX	0.1927		2009
1572	1	2028-01-01	2028-04-30	NOX	0.2197		2015
1572	1	2028-11-01	2028-12-31	NOX	0.2197		2015
1572	2	2028-01-01	2028-04-30	NOX	0.2212		2015
1572	2	2028-11-01	2028-12-31	NOX	0.2212		2015
1572	3	2028-01-01	2028-04-30	NOX	0.2178		2015
1572	3	2028-11-01	2028-12-31	NOX	0.2178		2015
1573	1	2028-01-01	2028-04-30	NOX	0.0251		2013
1573	1	2028-11-01	2028-12-31	NOX	0.0251		2013
1573	2	2028-01-01	2028-04-30	NOX	0.0309		2011
1573	2	2028-11-01	2028-12-31	NOX	0.0309		2011
1702	1	2028-01-01	2028-04-30	NOX	0.0488		2015
1702	1	2028-11-01	2028-12-31	NOX	0.0488		2015
1702	2	2028-01-01	2028-04-30	NOX	0.0443		2015
1702	2	2028-11-01	2028-12-31	NOX	0.0443		2015
1710	2	2028-01-01	2028-04-30	NOX	0.0366		2015

ORISPL Code	Unit ID	Factor Start Date	Factor End Date	Pollutant	Emission Rate	Con. Eff.	Best Observed Rate Year
1710	2	2028-11-01	2028-12-31	NOX	0.0366		2015
1710	3	2028-01-01	2028-04-30	NOX	0.0414		2015
1710	3	2028-11-01	2028-12-31	NOX	0.0414		2015
1733	1	2028-01-01	2028-04-30	NOX	0.038		2014
1733	1	2028-11-01	2028-12-31	NOX	0.038		2014
1733	3	2028-01-01	2028-04-30	NOX	0.0573		2011
1733	3	2028-11-01	2028-12-31	NOX	0.0573		2011
1733	4	2028-01-01	2028-04-30	NOX	0.0408		2013
1733	4	2028-11-01	2028-12-31	NOX	0.0408		2013
2167	1	2028-01-01	2028-04-30	NOX	0.0895		2008
2167	1	2028-11-01	2028-12-31	NOX	0.0895		2008
2167	2	2028-01-01	2028-04-30	NOX	0.0941		2009
2167	2	2028-11-01	2028-12-31	NOX	0.0941		2009
2168	MB3	2028-01-01	2028-04-30	NOX	0.0961		2010
2168	MB3	2028-11-01	2028-12-31	NOX	0.0961		2010
2364	1	2028-01-01	2028-04-30	NOX	0.1613		2005
2364	1	2028-11-01	2028-12-31	NOX	0.1613		2005
2364	2	2028-01-01	2028-04-30	NOX	0.159		2006
2364	2	2028-11-01	2028-12-31	NOX	0.159		2006
2367	4	2028-01-01	2028-04-30	NOX	0.1811		2007
2367	4	2028-11-01	2028-12-31	NOX	0.1811		2007
2367	6	2028-01-01	2028-04-30	NOX	0.1896		2007
2367	6	2028-11-01	2028-12-31	NOX	0.1896		2007
26	5	2028-01-01	2028-04-30	NOX	0.076		2007
26	5	2028-11-01	2028-12-31	NOX	0.076		2007
2712	1	2028-01-01	2028-04-30	NOX	0.084		2005
2712	1	2028-11-01	2028-12-31	NOX	0.084		2005
2712	2	2028-01-01	2028-04-30	NOX	0.0575		2011
2712	2	2028-11-01	2028-12-31	NOX	0.0575		2011
2712	3A	2028-01-01	2028-04-30	NOX	0.0742		2005
2712	3A	2028-11-01	2028-12-31	NOX	0.0742		2005
2712	3B	2028-01-01	2028-04-30	NOX	0.0756		2005
2712	3B	2028-11-01	2028-12-31	NOX	0.0756		2005
2712	4A	2028-01-01	2028-04-30	NOX	0.0793		2009
2712	4A	2028-11-01	2028-12-31	NOX	0.0793		2009
2712	4B	2028-01-01	2028-04-30	NOX	0.0793		2009
2712	4B	2028-11-01	2028-12-31	NOX	0.0793		2009
2721	5	2028-01-01	2028-04-30	NOX	0.056		2011
2721	5	2028-11-01	2028-12-31	NOX	0.056		2011
2727	1	2028-01-01	2028-04-30	NOX	0.196		2010
2727	1	2028-11-01	2028-12-31	NOX	0.196		2010
2727	2	2028-01-01	2028-04-30	NOX	0.1956		2010
2727	2	2028-11-01	2028-12-31	NOX	0.1956		2010
2727	3	2028-01-01	2028-04-30	NOX	0.0679		2009
2727	3	2028-11-01	2028-12-31	NOX	0.0679		2009
2727	4	2028-01-01	2028-04-30	NOX	0.2008		2008
2727	4	2028-11-01	2028-12-31	NOX	0.2008		2008
2828	1	2028-01-01	2028-04-30	NOX	0.0348		2009
2828	1	2028-11-01	2028-12-31	NOX	0.0348		2009
2828	2	2028-01-01	2028-04-30	NOX	0.0426		2009
2828	2	2028-11-01	2028-12-31	NOX	0.0426		2009
2828	3	2028-01-01	2028-04-30	NOX	0.0226		2007
2828	3	2028-11-01	2028-12-31	NOX	0.0226		2007
2832	7	2028-01-01	2028-04-30	NOX	0.0536		2007
2832	7	2028-11-01	2028-12-31	NOX	0.0536		2007
2832	8	2028-01-01	2028-04-30	NOX	0.054		2007
2832	8	2028-11-01	2028-12-31	NOX	0.054		2007
2836	12	2028-01-01	2028-04-30	NOX	0.2842		2013
2836	12	2028-11-01	2028-12-31	NOX	0.2842		2013
2840	4	2028-01-01	2028-04-30	NOX	0.0546		2010
2840	4	2028-11-01	2028-12-31	NOX	0.0546		2010
2866	5	2028-01-01	2028-04-30	NOX	0.1058		2012
2866	5	2028-11-01	2028-12-31	NOX	0.1058		2012
2866	7	2028-01-01	2028-04-30	NOX	0.1019		2014
2866	7	2028-11-01	2028-12-31	NOX	0.1019		2014
2876	1	2028-01-01	2028-04-30	NOX	0.0788		2005
2876	1	2028-11-01	2028-12-31	NOX	0.0788		2005

ORISPL Code	Unit ID	Factor Start Date	Factor End Date	Pollutant	Emission Rate	Con. Eff.	Best Observed Rate Year
2876	2	2028-01-01	2028-04-30	NOX	0.0792		2005
2876	2	2028-11-01	2028-12-31	NOX	0.0792		2005
2876	3	2028-01-01	2028-04-30	NOX	0.0787		2005
2876	3	2028-11-01	2028-12-31	NOX	0.0787		2005
2876	4	2028-01-01	2028-04-30	NOX	0.0786		2005
2876	4	2028-11-01	2028-12-31	NOX	0.0786		2005
2876	5	2028-01-01	2028-04-30	NOX	0.0785		2005
2876	5	2028-11-01	2028-12-31	NOX	0.0785		2005
3122	1	2028-01-01	2028-04-30	NOX	0.0667		2006
3122	1	2028-11-01	2028-12-31	NOX	0.0667		2006
3122	2	2028-01-01	2028-04-30	NOX	0.0826		2006
3122	2	2028-11-01	2028-12-31	NOX	0.0826		2006
3122	3	2028-01-01	2028-04-30	NOX	0.0872		2005
3122	3	2028-11-01	2028-12-31	NOX	0.0872		2005
3136	1	2028-01-01	2028-04-30	NOX	0.0431		2006
3136	1	2028-11-01	2028-12-31	NOX	0.0431		2006
3136	2	2028-01-01	2028-04-30	NOX	0.0433		2008
3136	2	2028-11-01	2028-12-31	NOX	0.0433		2008
3149	1	2028-01-01	2028-04-30	NOX	0.0581		2006
3149	1	2028-11-01	2028-12-31	NOX	0.0581		2006
3149	2	2028-01-01	2028-04-30	NOX	0.0578		2006
3149	2	2028-11-01	2028-12-31	NOX	0.0578		2006
3297	WAT1	2028-01-01	2028-04-30	NOX	0.0601		2007
3297	WAT1	2028-11-01	2028-12-31	NOX	0.0601		2007
3297	WAT2	2028-01-01	2028-04-30	NOX	0.0541		2006
3297	WAT2	2028-11-01	2028-12-31	NOX	0.0541		2006
3298	WIL1	2028-01-01	2028-04-30	NOX	0.0601		2005
3298	WIL1	2028-11-01	2028-12-31	NOX	0.0601		2005
3399	1	2028-01-01	2028-04-30	NOX	0.0588		2009
3399	1	2028-11-01	2028-12-31	NOX	0.0588		2009
3407	1	2028-01-01	2028-04-30	NOX	0.0498		2009
3407	1	2028-11-01	2028-12-31	NOX	0.0498		2009
3407	2	2028-01-01	2028-04-30	NOX	0.0501		2007
3407	2	2028-11-01	2028-12-31	NOX	0.0501		2007
3407	3	2028-01-01	2028-04-30	NOX	0.0504		2007
3407	3	2028-11-01	2028-12-31	NOX	0.0504		2007
3407	4	2028-01-01	2028-04-30	NOX	0.0501		2007
3407	4	2028-11-01	2028-12-31	NOX	0.0501		2007
3407	5	2028-01-01	2028-04-30	NOX	0.0486		2007
3407	5	2028-11-01	2028-12-31	NOX	0.0486		2007
3407	6	2028-01-01	2028-04-30	NOX	0.0448		2006
3407	6	2028-11-01	2028-12-31	NOX	0.0448		2006
3407	7	2028-01-01	2028-04-30	NOX	0.0447		2006
3407	7	2028-11-01	2028-12-31	NOX	0.0447		2006
3407	8	2028-01-01	2028-04-30	NOX	0.0448		2006
3407	8	2028-11-01	2028-12-31	NOX	0.0448		2006
3407	9	2028-01-01	2028-04-30	NOX	0.0449		2006
3407	9	2028-11-01	2028-12-31	NOX	0.0449		2006
3497	1	2028-01-01	2028-04-30	NOX	0.1261		2015
3497	1	2028-11-01	2028-12-31	NOX	0.1261		2015
3497	2	2028-01-01	2028-04-30	NOX	0.1305		2013
3497	2	2028-11-01	2028-12-31	NOX	0.1305		2013
3797	4	2028-01-01	2028-04-30	NOX	0.0487		2014
3797	4	2028-11-01	2028-12-31	NOX	0.0487		2014
3797	5	2028-01-01	2028-04-30	NOX	0.0309		2008
3797	5	2028-11-01	2028-12-31	NOX	0.0309		2008
3797	6	2028-01-01	2028-04-30	NOX	0.0326		2006
3797	6	2028-11-01	2028-12-31	NOX	0.0326		2006
3935	1	2028-01-01	2028-04-30	NOX	0.0317		2006
3935	1	2028-11-01	2028-12-31	NOX	0.0317		2006
3935	2	2028-01-01	2028-04-30	NOX	0.0312		2006
3935	2	2028-11-01	2028-12-31	NOX	0.0312		2006
3944	1	2028-01-01	2028-04-30	NOX	0.0634		2005
3944	1	2028-11-01	2028-12-31	NOX	0.0634		2005
3944	2	2028-01-01	2028-04-30	NOX	0.0662		2005
3944	2	2028-11-01	2028-12-31	NOX	0.0662		2005
3954	1	2028-01-01	2028-04-30	NOX	0.0539		2006

ORISPL Code	Unit ID	Factor Start Date	Factor End Date	Pollutant	Emission Rate	Con. Eff.	Best Observed Rate Year
3954	1	2028-11-01	2028-12-31	NOX	0.0539		2006
3954	2	2028-01-01	2028-04-30	NOX	0.0485		2006
3954	2	2028-11-01	2028-12-31	NOX	0.0485		2006
4041	7	2028-01-01	2028-04-30	NOX	0.0603		2015
4041	7	2028-11-01	2028-12-31	NOX	0.0603		2015
4041	8	2028-01-01	2028-04-30	NOX	0.0608		2015
4041	8	2028-11-01	2028-12-31	NOX	0.0608		2015
4050	5	2028-01-01	2028-04-30	NOX	0.0361		2014
4050	5	2028-11-01	2028-12-31	NOX	0.0361		2014
594	4	2028-01-01	2028-04-30	NOX	0.0657		2012
594	4	2028-11-01	2028-12-31	NOX	0.0657		2012
6004	1	2028-01-01	2028-04-30	NOX	0.0394		2005
6004	1	2028-11-01	2028-12-31	NOX	0.0394		2005
6004	2	2028-01-01	2028-04-30	NOX	0.039		2005
6004	2	2028-11-01	2028-12-31	NOX	0.039		2005
6018	2	2028-01-01	2028-04-30	NOX	0.0518		2006
6018	2	2028-11-01	2028-12-31	NOX	0.0518		2006
6019	1	2028-01-01	2028-04-30	NOX	0.0562		2006
6019	1	2028-11-01	2028-12-31	NOX	0.0562		2006
602	1	2028-01-01	2028-04-30	NOX	0.0589		2007
602	1	2028-11-01	2028-12-31	NOX	0.0589		2007
602	2	2028-01-01	2028-04-30	NOX	0.0733		2015
602	2	2028-11-01	2028-12-31	NOX	0.0733		2015
6041	1	2028-01-01	2028-04-30	NOX	0.0829		2008
6041	1	2028-11-01	2028-12-31	NOX	0.0829		2008
6041	2	2028-01-01	2028-04-30	NOX	0.0729		2006
6041	2	2028-11-01	2028-12-31	NOX	0.0729		2006
6085	14	2028-01-01	2028-04-30	NOX	0.0979		2013
6085	14	2028-11-01	2028-12-31	NOX	0.0979		2013
6113	1	2028-01-01	2028-04-30	NOX	0.0343		2007
6113	1	2028-11-01	2028-12-31	NOX	0.0343		2007
6113	2	2028-01-01	2028-04-30	NOX	0.0672		2006
6113	2	2028-11-01	2028-12-31	NOX	0.0672		2006
6113	3	2028-01-01	2028-04-30	NOX	0.0659		2005
6113	3	2028-11-01	2028-12-31	NOX	0.0659		2005
6113	4	2028-01-01	2028-04-30	NOX	0.0632		2008
6113	4	2028-11-01	2028-12-31	NOX	0.0632		2008
6113	5	2028-01-01	2028-04-30	NOX	0.0597		2007
6113	5	2028-11-01	2028-12-31	NOX	0.0597		2007
6147	2	2028-01-01	2028-04-30	NOX	0.1187		2014
6147	2	2028-11-01	2028-12-31	NOX	0.1187		2014
6147	3	2028-01-01	2028-04-30	NOX	0.1485		2014
6147	3	2028-11-01	2028-12-31	NOX	0.1485		2014
6213	2SG1	2028-01-01	2028-04-30	NOX	0.0587		2015
6213	2SG1	2028-11-01	2028-12-31	NOX	0.0587		2015
6249	1	2028-01-01	2028-04-30	NOX	0.0623		2005
6249	1	2028-11-01	2028-12-31	NOX	0.0623		2005
6249	2	2028-01-01	2028-04-30	NOX	0.0679		2005
6249	2	2028-11-01	2028-12-31	NOX	0.0679		2005
6249	3	2028-01-01	2028-04-30	NOX	0.0812		2015
6249	3	2028-11-01	2028-12-31	NOX	0.0812		2015
6249	4	2028-01-01	2028-04-30	NOX	0.0869		2012
6249	4	2028-11-01	2028-12-31	NOX	0.0869		2012
6250	1A	2028-01-01	2028-04-30	NOX	0.061		2007
6250	1A	2028-11-01	2028-12-31	NOX	0.061		2007
6250	1B	2028-01-01	2028-04-30	NOX	0.0614		2007
6250	1B	2028-11-01	2028-12-31	NOX	0.0614		2007
6257	1	2028-01-01	2028-04-30	NOX	0.0613		2014
6257	1	2028-11-01	2028-12-31	NOX	0.0613		2014
6257	2	2028-01-01	2028-04-30	NOX	0.0606		2014
6257	2	2028-11-01	2028-12-31	NOX	0.0606		2014
6257	4	2028-01-01	2028-04-30	NOX	0.0627		2013
6257	4	2028-11-01	2028-12-31	NOX	0.0627		2013
6264	1	2028-01-01	2028-04-30	NOX	0.0387		2007
6264	1	2028-11-01	2028-12-31	NOX	0.0387		2007
6705	4	2028-01-01	2028-04-30	NOX	0.0948		2007
6705	4	2028-11-01	2028-12-31	NOX	0.0948		2007

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6768	1	2028-01-01	2028-04-30	NOX	0.1046		2013
6768	1	2028-11-01	2028-12-31	NOX	0.1046		2013
6823	W1	2028-01-01	2028-04-30	NOX	0.0477		2006
6823	W1	2028-11-01	2028-12-31	NOX	0.0477		2006
703	1BLR	2028-01-01	2028-04-30	NOX	0.0547		2008
703	1BLR	2028-11-01	2028-12-31	NOX	0.0547		2008
703	2BLR	2028-01-01	2028-04-30	NOX	0.0543		2006
703	2BLR	2028-11-01	2028-12-31	NOX	0.0543		2006
703	3BLR	2028-01-01	2028-04-30	NOX	0.0553		2006
703	3BLR	2028-11-01	2028-12-31	NOX	0.0553		2006
703	4BLR	2028-01-01	2028-04-30	NOX	0.0525		2013
703	4BLR	2028-11-01	2028-12-31	NOX	0.0525		2013
7343	4	2028-01-01	2028-04-30	NOX	0.1873		2015
7343	4	2028-11-01	2028-12-31	NOX	0.1873		2015
8042	2	2028-01-01	2028-04-30	NOX	0.0382		2009
8042	2	2028-11-01	2028-12-31	NOX	0.0382		2009
8102	1	2028-01-01	2028-04-30	NOX	0.0686		2007
8102	1	2028-11-01	2028-12-31	NOX	0.0686		2007
8102	2	2028-01-01	2028-04-30	NOX	0.0553		2005
8102	2	2028-11-01	2028-12-31	NOX	0.0553		2005
8226	1	2028-01-01	2028-04-30	NOX	0.0901		2006
8226	1	2028-11-01	2028-12-31	NOX	0.0901		2006
876	1	2028-01-01	2028-04-30	NOX	0.0577		2013
876	1	2028-11-01	2028-12-31	NOX	0.0577		2013
876	2	2028-01-01	2028-04-30	NOX	0.06		2009
876	2	2028-11-01	2028-12-31	NOX	0.06		2009
879	51	2028-01-01	2028-04-30	NOX	0.0985		2013
879	51	2028-11-01	2028-12-31	NOX	0.0985		2013
879	52	2028-01-01	2028-04-30	NOX	0.0987		2015
879	52	2028-11-01	2028-12-31	NOX	0.0987		2015
879	61	2028-01-01	2028-04-30	NOX	0.0973		2013
879	61	2028-11-01	2028-12-31	NOX	0.0973		2013
879	62	2028-01-01	2028-04-30	NOX	0.0885		2015
879	62	2028-11-01	2028-12-31	NOX	0.0885		2015
889	2	2028-01-01	2028-04-30	NOX	0.0509		2010
889	2	2028-11-01	2028-12-31	NOX	0.0509		2010
976	4	2028-01-01	2028-04-30	NOX	0.0785		2015
976	4	2028-11-01	2028-12-31	NOX	0.0785		2015
983	1	2028-01-01	2028-04-30	NOX	0.0735		2005
983	1	2028-11-01	2028-12-31	NOX	0.0735		2005
983	2	2028-01-01	2028-04-30	NOX	0.075		2005
983	2	2028-11-01	2028-12-31	NOX	0.075		2005
983	3	2028-01-01	2028-04-30	NOX	0.0742		2005
983	3	2028-11-01	2028-12-31	NOX	0.0742		2005
994	2	2028-01-01	2028-04-30	NOX	0.051		2005
994	2	2028-11-01	2028-12-31	NOX	0.051		2005
994	3	2028-01-01	2028-04-30	NOX	0.0466		2005
994	3	2028-11-01	2028-12-31	NOX	0.0466		2005
997	12	2028-01-01	2028-04-30	NOX	0.092		2005
997	12	2028-11-01	2028-12-31	NOX	0.092		2005
1241	1	2028-01-01	2028-04-30	NOX	0.081		2011
1241	1	2028-11-01	2028-12-31	NOX	0.081		2011
1241	2	2028-01-01	2028-04-30	NOX	0.0908		2015
1241	2	2028-11-01	2028-12-31	NOX	0.0908		2015
1356	1	2028-01-01	2028-04-30	NOX	0.0448		2005
1356	1	2028-11-01	2028-12-31	NOX	0.0448		2005
1356	3	2028-01-01	2028-04-30	NOX	0.0272		2005
1356	3	2028-11-01	2028-12-31	NOX	0.0272		2005
1356	4	2028-01-01	2028-04-30	NOX	0.0272		2005
1356	4	2028-11-01	2028-12-31	NOX	0.0272		2005
1364	3	2028-01-01	2028-04-30	NOX	0.045		2005
1364	3	2028-11-01	2028-12-31	NOX	0.045		2005
1364	4	2028-01-01	2028-04-30	NOX	0.0374		2007
1364	4	2028-11-01	2028-12-31	NOX	0.0374		2007
1378	3	2028-01-01	2028-04-30	NOX	0.1001		2005
1378	3	2028-11-01	2028-12-31	NOX	0.1001		2005
1552	1	2028-01-01	2028-04-30	NOX	0.2783		2015

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1552	1	2028-11-01	2028-12-31	NOX	0.2783		2015
1552	2	2028-01-01	2028-04-30	NOX	0.2351		2015
1552	2	2028-11-01	2028-12-31	NOX	0.2351		2015
1554	2	2028-01-01	2028-04-30	NOX	0.2222		2015
1554	2	2028-11-01	2028-12-31	NOX	0.2222		2015
1554	3	2028-01-01	2028-04-30	NOX	0.0552		2015
1554	3	2028-11-01	2028-12-31	NOX	0.0552		2015
1571	1	2028-01-01	2028-04-30	NOX	0.104		2014
1571	1	2028-11-01	2028-12-31	NOX	0.104		2014
1571	2	2028-01-01	2028-04-30	NOX	0.1927		2009
1571	2	2028-11-01	2028-12-31	NOX	0.1927		2009
1572	1	2028-01-01	2028-04-30	NOX	0.2197		2015
1572	1	2028-11-01	2028-12-31	NOX	0.2197		2015
1572	2	2028-01-01	2028-04-30	NOX	0.2212		2015
1572	2	2028-11-01	2028-12-31	NOX	0.2212		2015
1572	3	2028-01-01	2028-04-30	NOX	0.2178		2015
1572	3	2028-11-01	2028-12-31	NOX	0.2178		2015
1573	1	2028-01-01	2028-04-30	NOX	0.0251		2013
1573	1	2028-11-01	2028-12-31	NOX	0.0251		2013
1573	2	2028-01-01	2028-04-30	NOX	0.0309		2011
1573	2	2028-11-01	2028-12-31	NOX	0.0309		2011
1702	1	2028-01-01	2028-04-30	NOX	0.0488		2015
1702	1	2028-11-01	2028-12-31	NOX	0.0488		2015
1702	2	2028-01-01	2028-04-30	NOX	0.0443		2015
1702	2	2028-11-01	2028-12-31	NOX	0.0443		2015
1710	2	2028-01-01	2028-04-30	NOX	0.0366		2015
1710	2	2028-11-01	2028-12-31	NOX	0.0366		2015
1710	3	2028-01-01	2028-04-30	NOX	0.0414		2015
1710	3	2028-11-01	2028-12-31	NOX	0.0414		2015
1733	1	2028-01-01	2028-04-30	NOX	0.038		2014
1733	1	2028-11-01	2028-12-31	NOX	0.038		2014
1733	3	2028-01-01	2028-04-30	NOX	0.0573		2011
1733	3	2028-11-01	2028-12-31	NOX	0.0573		2011
1733	4	2028-01-01	2028-04-30	NOX	0.0408		2013
1733	4	2028-11-01	2028-12-31	NOX	0.0408		2013
2167	1	2028-01-01	2028-04-30	NOX	0.0895		2008
2167	1	2028-11-01	2028-12-31	NOX	0.0895		2008
2167	2	2028-01-01	2028-04-30	NOX	0.0941		2009
2167	2	2028-11-01	2028-12-31	NOX	0.0941		2009
2168	MB3	2028-01-01	2028-04-30	NOX	0.0961		2010
2168	MB3	2028-11-01	2028-12-31	NOX	0.0961		2010
2364	1	2028-01-01	2028-04-30	NOX	0.1613		2005
2364	1	2028-11-01	2028-12-31	NOX	0.1613		2005
2364	2	2028-01-01	2028-04-30	NOX	0.159		2006
2364	2	2028-11-01	2028-12-31	NOX	0.159		2006
2367	4	2028-01-01	2028-04-30	NOX	0.1811		2007
2367	4	2028-11-01	2028-12-31	NOX	0.1811		2007
2367	6	2028-01-01	2028-04-30	NOX	0.1896		2007
2367	6	2028-11-01	2028-12-31	NOX	0.1896		2007
26	5	2028-01-01	2028-04-30	NOX	0.076		2007
26	5	2028-11-01	2028-12-31	NOX	0.076		2007
2712	1	2028-01-01	2028-04-30	NOX	0.084		2005
2712	1	2028-11-01	2028-12-31	NOX	0.084		2005
2712	2	2028-01-01	2028-04-30	NOX	0.0575		2011
2712	2	2028-11-01	2028-12-31	NOX	0.0575		2011
2712	3A	2028-01-01	2028-04-30	NOX	0.0742		2005
2712	3A	2028-11-01	2028-12-31	NOX	0.0742		2005
2712	3B	2028-01-01	2028-04-30	NOX	0.0756		2005
2712	3B	2028-11-01	2028-12-31	NOX	0.0756		2005
2712	4A	2028-01-01	2028-04-30	NOX	0.0793		2009
2712	4A	2028-11-01	2028-12-31	NOX	0.0793		2009
2712	4B	2028-01-01	2028-04-30	NOX	0.0793		2009
2712	4B	2028-11-01	2028-12-31	NOX	0.0793		2009
2721	5	2028-01-01	2028-04-30	NOX	0.056		2011
2721	5	2028-11-01	2028-12-31	NOX	0.056		2011
2727	1	2028-01-01	2028-04-30	NOX	0.196		2010
2727	1	2028-11-01	2028-12-31	NOX	0.196		2010

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2727	2	2028-01-01	2028-04-30	NOX	0.1956		2010
2727	2	2028-11-01	2028-12-31	NOX	0.1956		2010
2727	3	2028-01-01	2028-04-30	NOX	0.0679		2009
2727	3	2028-11-01	2028-12-31	NOX	0.0679		2009
2727	4	2028-01-01	2028-04-30	NOX	0.2008		2008
2727	4	2028-11-01	2028-12-31	NOX	0.2008		2008
2828	1	2028-01-01	2028-04-30	NOX	0.0348		2009
2828	1	2028-11-01	2028-12-31	NOX	0.0348		2009
2828	2	2028-01-01	2028-04-30	NOX	0.0426		2009
2828	2	2028-11-01	2028-12-31	NOX	0.0426		2009
2828	3	2028-01-01	2028-04-30	NOX	0.0226		2007
2828	3	2028-11-01	2028-12-31	NOX	0.0226		2007
2832	7	2028-01-01	2028-04-30	NOX	0.0536		2007
2832	7	2028-11-01	2028-12-31	NOX	0.0536		2007
2832	8	2028-01-01	2028-04-30	NOX	0.054		2007
2832	8	2028-11-01	2028-12-31	NOX	0.054		2007
2836	12	2028-01-01	2028-04-30	NOX	0.2842		2013
2836	12	2028-11-01	2028-12-31	NOX	0.2842		2013
2840	4	2028-01-01	2028-04-30	NOX	0.0546		2010
2840	4	2028-11-01	2028-12-31	NOX	0.0546		2010
2866	5	2028-01-01	2028-04-30	NOX	0.1058		2012
2866	5	2028-11-01	2028-12-31	NOX	0.1058		2012
2866	7	2028-01-01	2028-04-30	NOX	0.1019		2014
2866	7	2028-11-01	2028-12-31	NOX	0.1019		2014
2876	1	2028-01-01	2028-04-30	NOX	0.0788		2005
2876	1	2028-11-01	2028-12-31	NOX	0.0788		2005
2876	2	2028-01-01	2028-04-30	NOX	0.0792		2005
2876	2	2028-11-01	2028-12-31	NOX	0.0792		2005
2876	3	2028-01-01	2028-04-30	NOX	0.0787		2005
2876	3	2028-11-01	2028-12-31	NOX	0.0787		2005
2876	4	2028-01-01	2028-04-30	NOX	0.0786		2005
2876	4	2028-11-01	2028-12-31	NOX	0.0786		2005
2876	5	2028-01-01	2028-04-30	NOX	0.0785		2005
2876	5	2028-11-01	2028-12-31	NOX	0.0785		2005
3122	1	2028-01-01	2028-04-30	NOX	0.0667		2006
3122	1	2028-11-01	2028-12-31	NOX	0.0667		2006
3122	2	2028-01-01	2028-04-30	NOX	0.0826		2006
3122	2	2028-11-01	2028-12-31	NOX	0.0826		2006
3122	3	2028-01-01	2028-04-30	NOX	0.0872		2005
3122	3	2028-11-01	2028-12-31	NOX	0.0872		2005
3136	1	2028-01-01	2028-04-30	NOX	0.0431		2006
3136	1	2028-11-01	2028-12-31	NOX	0.0431		2006
3136	2	2028-01-01	2028-04-30	NOX	0.0433		2008
3136	2	2028-11-01	2028-12-31	NOX	0.0433		2008
3149	1	2028-01-01	2028-04-30	NOX	0.0581		2006
3149	1	2028-11-01	2028-12-31	NOX	0.0581		2006
3149	2	2028-01-01	2028-04-30	NOX	0.0578		2006
3149	2	2028-11-01	2028-12-31	NOX	0.0578		2006
3297	WAT1	2028-01-01	2028-04-30	NOX	0.0601		2007
3297	WAT1	2028-11-01	2028-12-31	NOX	0.0601		2007
3297	WAT2	2028-01-01	2028-04-30	NOX	0.0541		2006
3297	WAT2	2028-11-01	2028-12-31	NOX	0.0541		2006
3298	WIL1	2028-01-01	2028-04-30	NOX	0.0601		2005
3298	WIL1	2028-11-01	2028-12-31	NOX	0.0601		2005
3399	1	2028-01-01	2028-04-30	NOX	0.0588		2009
3399	1	2028-11-01	2028-12-31	NOX	0.0588		2009
3407	1	2028-01-01	2028-04-30	NOX	0.0498		2009
3407	1	2028-11-01	2028-12-31	NOX	0.0498		2009
3407	2	2028-01-01	2028-04-30	NOX	0.0501		2007
3407	2	2028-11-01	2028-12-31	NOX	0.0501		2007
3407	3	2028-01-01	2028-04-30	NOX	0.0504		2007
3407	3	2028-11-01	2028-12-31	NOX	0.0504		2007
3407	4	2028-01-01	2028-04-30	NOX	0.0501		2007
3407	4	2028-11-01	2028-12-31	NOX	0.0501		2007
3407	5	2028-01-01	2028-04-30	NOX	0.0486		2007
3407	5	2028-11-01	2028-12-31	NOX	0.0486		2007
3407	6	2028-01-01	2028-04-30	NOX	0.0448		2006

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3407	6	2028-11-01	2028-12-31	NOX	0.0448		2006
3407	7	2028-01-01	2028-04-30	NOX	0.0447		2006
3407	7	2028-11-01	2028-12-31	NOX	0.0447		2006
3407	8	2028-01-01	2028-04-30	NOX	0.0448		2006
3407	8	2028-11-01	2028-12-31	NOX	0.0448		2006
3407	9	2028-01-01	2028-04-30	NOX	0.0449		2006
3407	9	2028-11-01	2028-12-31	NOX	0.0449		2006
3497	1	2028-01-01	2028-04-30	NOX	0.1261		2015
3497	1	2028-11-01	2028-12-31	NOX	0.1261		2015
3497	2	2028-01-01	2028-04-30	NOX	0.1305		2013
3497	2	2028-11-01	2028-12-31	NOX	0.1305		2013
3797	4	2028-01-01	2028-04-30	NOX	0.0487		2014
3797	4	2028-11-01	2028-12-31	NOX	0.0487		2014
3797	5	2028-01-01	2028-04-30	NOX	0.0309		2008
3797	5	2028-11-01	2028-12-31	NOX	0.0309		2008
3797	6	2028-01-01	2028-04-30	NOX	0.0326		2006
3797	6	2028-11-01	2028-12-31	NOX	0.0326		2006
3935	1	2028-01-01	2028-04-30	NOX	0.0317		2006
3935	1	2028-11-01	2028-12-31	NOX	0.0317		2006
3935	2	2028-01-01	2028-04-30	NOX	0.0312		2006
3935	2	2028-11-01	2028-12-31	NOX	0.0312		2006
3944	1	2028-01-01	2028-04-30	NOX	0.0634		2005
3944	1	2028-11-01	2028-12-31	NOX	0.0634		2005
3944	2	2028-01-01	2028-04-30	NOX	0.0662		2005
3944	2	2028-11-01	2028-12-31	NOX	0.0662		2005
3954	1	2028-01-01	2028-04-30	NOX	0.0539		2006
3954	1	2028-11-01	2028-12-31	NOX	0.0539		2006
3954	2	2028-01-01	2028-04-30	NOX	0.0485		2006
3954	2	2028-11-01	2028-12-31	NOX	0.0485		2006
4041	7	2028-01-01	2028-04-30	NOX	0.0603		2015
4041	7	2028-11-01	2028-12-31	NOX	0.0603		2015
4041	8	2028-01-01	2028-04-30	NOX	0.0608		2015
4041	8	2028-11-01	2028-12-31	NOX	0.0608		2015
4050	5	2028-01-01	2028-04-30	NOX	0.0361		2014
4050	5	2028-11-01	2028-12-31	NOX	0.0361		2014
594	4	2028-01-01	2028-04-30	NOX	0.0657		2012
594	4	2028-11-01	2028-12-31	NOX	0.0657		2012
6004	1	2028-01-01	2028-04-30	NOX	0.0394		2005
6004	1	2028-11-01	2028-12-31	NOX	0.0394		2005
6004	2	2028-01-01	2028-04-30	NOX	0.039		2005
6004	2	2028-11-01	2028-12-31	NOX	0.039		2005
6018	2	2028-01-01	2028-04-30	NOX	0.0518		2006
6018	2	2028-11-01	2028-12-31	NOX	0.0518		2006
6019	1	2028-01-01	2028-04-30	NOX	0.0562		2006
6019	1	2028-11-01	2028-12-31	NOX	0.0562		2006
602	1	2028-01-01	2028-04-30	NOX	0.0589		2007
602	1	2028-11-01	2028-12-31	NOX	0.0589		2007
602	2	2028-01-01	2028-04-30	NOX	0.0733		2015
602	2	2028-11-01	2028-12-31	NOX	0.0733		2015
6041	1	2028-01-01	2028-04-30	NOX	0.0829		2008
6041	1	2028-11-01	2028-12-31	NOX	0.0829		2008
6041	2	2028-01-01	2028-04-30	NOX	0.0729		2006
6041	2	2028-11-01	2028-12-31	NOX	0.0729		2006
6085	14	2028-01-01	2028-04-30	NOX	0.0979		2013
6085	14	2028-11-01	2028-12-31	NOX	0.0979		2013
6113	1	2028-01-01	2028-04-30	NOX	0.0343		2007
6113	1	2028-11-01	2028-12-31	NOX	0.0343		2007
6113	2	2028-01-01	2028-04-30	NOX	0.0672		2006
6113	2	2028-11-01	2028-12-31	NOX	0.0672		2006
6113	3	2028-01-01	2028-04-30	NOX	0.0659		2005
6113	3	2028-11-01	2028-12-31	NOX	0.0659		2005
6113	4	2028-01-01	2028-04-30	NOX	0.0632		2008
6113	4	2028-11-01	2028-12-31	NOX	0.0632		2008
6113	5	2028-01-01	2028-04-30	NOX	0.0597		2007
6113	5	2028-11-01	2028-12-31	NOX	0.0597		2007
6147	2	2028-01-01	2028-04-30	NOX	0.1187		2014
6147	2	2028-11-01	2028-12-31	NOX	0.1187		2014

ORISPL Code	Unit ID	Factor Start Date	Factor End Date	Pollutant	Emission Rate	Con. Eff.	Best Observed Rate Year
6147	3	2028-01-01	2028-04-30	NOX	0.1485		2014
6147	3	2028-11-01	2028-12-31	NOX	0.1485		2014
6213	2SG1	2028-01-01	2028-04-30	NOX	0.0587		2015
6213	2SG1	2028-11-01	2028-12-31	NOX	0.0587		2015
6249	1	2028-01-01	2028-04-30	NOX	0.0623		2005
6249	1	2028-11-01	2028-12-31	NOX	0.0623		2005
6249	2	2028-01-01	2028-04-30	NOX	0.0679		2005
6249	2	2028-11-01	2028-12-31	NOX	0.0679		2005
6249	3	2028-01-01	2028-04-30	NOX	0.0812		2015
6249	3	2028-11-01	2028-12-31	NOX	0.0812		2015
6249	4	2028-01-01	2028-04-30	NOX	0.0869		2012
6249	4	2028-11-01	2028-12-31	NOX	0.0869		2012
6250	1A	2028-01-01	2028-04-30	NOX	0.061		2007
6250	1A	2028-11-01	2028-12-31	NOX	0.061		2007
6250	1B	2028-01-01	2028-04-30	NOX	0.0614		2007
6250	1B	2028-11-01	2028-12-31	NOX	0.0614		2007
6257	1	2028-01-01	2028-04-30	NOX	0.0613		2014
6257	1	2028-11-01	2028-12-31	NOX	0.0613		2014
6257	2	2028-01-01	2028-04-30	NOX	0.0606		2014
6257	2	2028-11-01	2028-12-31	NOX	0.0606		2014
6257	4	2028-01-01	2028-04-30	NOX	0.0627		2013
6257	4	2028-11-01	2028-12-31	NOX	0.0627		2013
6264	1	2028-01-01	2028-04-30	NOX	0.0387		2007
6264	1	2028-11-01	2028-12-31	NOX	0.0387		2007
6705	4	2028-01-01	2028-04-30	NOX	0.0948		2007
6705	4	2028-11-01	2028-12-31	NOX	0.0948		2007
6768	1	2028-01-01	2028-04-30	NOX	0.1046		2013
6768	1	2028-11-01	2028-12-31	NOX	0.1046		2013
6823	W1	2028-01-01	2028-04-30	NOX	0.0477		2006
6823	W1	2028-11-01	2028-12-31	NOX	0.0477		2006
703	1BLR	2028-01-01	2028-04-30	NOX	0.0547		2008
703	1BLR	2028-11-01	2028-12-31	NOX	0.0547		2008
703	2BLR	2028-01-01	2028-04-30	NOX	0.0543		2006
703	2BLR	2028-11-01	2028-12-31	NOX	0.0543		2006
703	3BLR	2028-01-01	2028-04-30	NOX	0.0553		2006
703	3BLR	2028-11-01	2028-12-31	NOX	0.0553		2006
703	4BLR	2028-01-01	2028-04-30	NOX	0.0525		2013
703	4BLR	2028-11-01	2028-12-31	NOX	0.0525		2013
7343	4	2028-01-01	2028-04-30	NOX	0.1873		2015
7343	4	2028-11-01	2028-12-31	NOX	0.1873		2015
8042	2	2028-01-01	2028-04-30	NOX	0.0382		2009
8042	2	2028-11-01	2028-12-31	NOX	0.0382		2009
8102	1	2028-01-01	2028-04-30	NOX	0.0686		2007
8102	1	2028-11-01	2028-12-31	NOX	0.0686		2007
8102	2	2028-01-01	2028-04-30	NOX	0.0553		2005
8102	2	2028-11-01	2028-12-31	NOX	0.0553		2005
8226	1	2028-01-01	2028-04-30	NOX	0.0901		2006
8226	1	2028-11-01	2028-12-31	NOX	0.0901		2006
876	1	2028-01-01	2028-04-30	NOX	0.0577		2013
876	1	2028-11-01	2028-12-31	NOX	0.0577		2013
876	2	2028-01-01	2028-04-30	NOX	0.06		2009
876	2	2028-11-01	2028-12-31	NOX	0.06		2009
879	51	2028-01-01	2028-04-30	NOX	0.0985		2013
879	51	2028-11-01	2028-12-31	NOX	0.0985		2013
879	52	2028-01-01	2028-04-30	NOX	0.0987		2015
879	52	2028-11-01	2028-12-31	NOX	0.0987		2015
879	61	2028-01-01	2028-04-30	NOX	0.0973		2013
879	61	2028-11-01	2028-12-31	NOX	0.0973		2013
879	62	2028-01-01	2028-04-30	NOX	0.0885		2015
879	62	2028-11-01	2028-12-31	NOX	0.0885		2015
889	2	2028-01-01	2028-04-30	NOX	0.0509		2010
889	2	2028-11-01	2028-12-31	NOX	0.0509		2010
976	4	2028-01-01	2028-04-30	NOX	0.0785		2015
976	4	2028-11-01	2028-12-31	NOX	0.0785		2015
983	1	2028-01-01	2028-04-30	NOX	0.0735		2005
983	1	2028-11-01	2028-12-31	NOX	0.0735		2005
983	2	2028-01-01	2028-04-30	NOX	0.075		2005

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ORISPL Code	Unit ID	Factor Start Date	Factor End Date	Pollutant	Emission Rate	Con. Eff.	Best Observed Rate Year
983	2	2028-11-01	2028-12-31	NOX	0.075		2005
983	3	2028-01-01	2028-04-30	NOX	0.0742		2005
983	3	2028-11-01	2028-12-31	NOX	0.0742		2005
994	2	2028-01-01	2028-04-30	NOX	0.051		2005
994	2	2028-11-01	2028-12-31	NOX	0.051		2005
994	3	2028-01-01	2028-04-30	NOX	0.0466		2005
994	3	2028-11-01	2028-12-31	NOX	0.0466		2005
997	12	2028-01-01	2028-04-30	NOX	0.092		2005
997	12	2028-11-01	2028-12-31	NOX	0.092		2005

Appendix B

Table 4: Unit level results in total tons during non-ozone season from ERTAC v2.7, and the best observed rate (BOR) runs

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
MANE-VU	**CT**	AES Thames	**10675**	UNITA	0.00	0.00	0
MANE-VU	**CT**	AES Thames	**10675**	UNITB	0.00	0.00	0
MANE-VU	**CT**	Bridgeport Harbor Station	**568**	BHB3	42.58	42.58	0
MANE-VU	**DE**	Indian River	**594**	1	0.00	0.00	0
MANE-VU	**DE**	Indian River	**594**	3	0.00	0.00	0
MANE-VU	**DE**	Indian River	**594**	4	242.09	159.66	-82.42
MANE-VU	**MA**	Brayton Point	**1619**	1	0.00	0.00	0
MANE-VU	**MA**	Brayton Point	**1619**	2	0.00	0.00	0
MANE-VU	**MA**	Brayton Point	**1619**	3	0.00	0.00	0
MANE-VU	**MA**	Mount Tom	**1606**	1	0.00	0.00	0
MANE-VU	**MA**	Salem Harbor	**1626**	1	0.00	0.00	0
MANE-VU	**MA**	Salem Harbor	**1626**	2	0.00	0.00	0
MANE-VU	**MA**	Salem Harbor	**1626**	3	0.00	0.00	0
MANE-VU	**MD**	AES Warrior Run	**10678**	001	472.61	472.61	0
MANE-VU	**MD**	Brandon Shores	**602**	1	1,139.49	463.48	-676.01
MANE-VU	**MD**	Brandon Shores	**602**	2	1,289.18	663.05	-626.13
MANE-VU	**MD**	C P Crane	**1552**	1	155.93	96.58	-59.34
MANE-VU	**MD**	C P Crane	**1552**	2	170.28	98.46	-71.82
MANE-VU	**MD**	Herbert A Wagner	**1554**	2	93.56	52.61	-40.96
MANE-VU	**MD**	Herbert A Wagner	**1554**	3	620.52	283.23	-337.29
MANE-VU	**MD**	Mirant Chalk Point	**1571**	1	283.29	154.41	-128.88
MANE-VU	**MD**	Mirant Chalk Point	**1571**	2	318.36	242.58	-75.78
MANE-VU	**MD**	Mirant Dickerson	**1572**	1	89.52	69.06	-20.46
MANE-VU	**MD**	Mirant Dickerson	**1572**	2	122.50	93.34	-29.16
MANE-VU	**MD**	Mirant Dickerson	**1572**	3	121.27	91.71	-29.56
MANE-VU	**MD**	Mirant Morgantown	**1573**	1	258.83	195.43	-63.41
MANE-VU	**MD**	Mirant Morgantown	**1573**	2	181.52	165.81	-15.71
MANE-VU	**MD**	R. Paul Smith Power Station	**1570**	11	0.00	0.00	0
MANE-VU	**MD**	R. Paul Smith Power Station	**1570**	9	0.00	0.00	0
MANE-VU	**NH**	Merrimack	**2364**	1	188.91	120.88	-68.04
MANE-VU	**NH**	Merrimack	**2364**	2	306.33	182.49	-123.83
MANE-VU	**NH**	Schiller	**2367**	4	53.76	32.83	-20.92
MANE-VU	**NH**	Schiller	**2367**	6	63.00	41.68	-21.33
MANE-VU	**NJ**	B L England	**2378**	1	0.00	0.00	0
MANE-VU	**NJ**	B L England	**2378**	2	0.00	0.00	0
MANE-VU	**NJ**	Carneys Point	**10566**	1001	247.22	247.22	0
MANE-VU	**NJ**	Carneys Point	**10566**	1002	251.41	251.41	0
MANE-VU	**NJ**	Deepwater	**2384**	8	0.00	0.00	0
MANE-VU	**NJ**	Hudson Generating Station	**2403**	2	0.00	0.00	0
MANE-VU	**NJ**	Logan Generating Plant	**10043**	1001	235.74	235.74	0
MANE-VU	**NJ**	Mercer Generating Station	**2408**	1	0.00	0.00	0
MANE-VU	**NJ**	Mercer Generating Station	**2408**	2	0.00	0.00	0
MANE-VU	**NY**	AES Cayuga, LLC	**2535**	1	135.83	135.83	0
MANE-VU	**NY**	AES Cayuga, LLC	**2535**	2	129.12	129.12	0
MANE-VU	**NY**	AES Greenidge	**2527**	6	0.00	0.00	0
MANE-VU	**NY**	AES Somerset (Kintigh)	**6082**	1	816.12	816.12	0
MANE-VU	**NY**	AES Westover (Goudey)	**2526**	13	0.00	0.00	0
MANE-VU	**NY**	Black River Generation, LLC	**10464**	E0001	0.00	0.00	0
MANE-VU	**NY**	Black River Generation, LLC	**10464**	E0002	0.00	0.00	0
MANE-VU	**NY**	Black River Generation, LLC	**10464**	E0003	0.00	0.00	0
MANE-VU	**NY**	Dunkirk	**2554**	1	51.57	51.57	0
MANE-VU	**NY**	Dunkirk	**2554**	2	62.46	62.46	0
MANE-VU	**NY**	Dunkirk	**2554**	3	166.83	166.83	0
MANE-VU	**NY**	Dunkirk	**2554**	4	134.83	134.83	0
MANE-VU	**NY**	Dynegy Danskammer	**2480**	3	0.00	0.00	0
MANE-VU	**NY**	Dynegy Danskammer	**2480**	4	0.00	0.00	0

Impact of Wintertime SCR/SNRC Optimization on Visibility Impairing Nitrate Precursor Emissions

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
MANE-VU	**NY**	Huntley Power	**2549**	67	148.99	148.99	0
MANE-VU	**NY**	Huntley Power	**2549**	68	142.64	142.64	0
MANE-VU	**NY**	Niagara Generation, LLC	**50202**	1	0.00	0.00	0
MANE-VU	**NY**	S A Carlson	**2682**	10	0.00	0.00	0
MANE-VU	**NY**	S A Carlson	**2682**	12	0.00	0.00	0
MANE-VU	**NY**	S A Carlson	**2682**	9	0.00	0.00	0
MANE-VU	**NY**	Syracuse Energy Corporation	**50651**	BLR1	0.00	0.00	0
MANE-VU	**PA**	AES Beaver Valley LLC	**10676**	032	0.00	0.00	0
MANE-VU	**PA**	AES Beaver Valley LLC	**10676**	033	0.00	0.00	0
MANE-VU	**PA**	AES Beaver Valley LLC	**10676**	034	0.00	0.00	0
MANE-VU	**PA**	AES Beaver Valley LLC	**10676**	035	0.00	0.00	0
MANE-VU	**PA**	Armstrong Power Station	**3178**	1	0.00	0.00	0
MANE-VU	**PA**	Armstrong Power Station	**3178**	2	0.00	0.00	0
MANE-VU	**PA**	Bruce Mansfield	**6094**	1	2,223.60	2,223.60	0
MANE-VU	**PA**	Bruce Mansfield	**6094**	2	1,992.25	1,992.25	0
MANE-VU	**PA**	Bruce Mansfield	**6094**	3	3,888.10	3,888.10	0
MANE-VU	**PA**	Brunner Island	**3140**	1	477.43	477.43	0
MANE-VU	**PA**	Brunner Island	**3140**	2	441.12	441.12	0
MANE-VU	**PA**	Brunner Island	**3140**	3	1,001.39	1,001.39	0
MANE-VU	**PA**	Cambria Cogen	**10641**	1	222.21	222.21	0
MANE-VU	**PA**	Cambria Cogen	**10641**	2	241.91	241.91	0
MANE-VU	**PA**	Cheswick	**8226**	1	1,865.18	809.38	-1055.8
MANE-VU	**PA**	Colver Power Project	**10143**	AAB01	432.08	432.08	0
MANE-VU	**PA**	Conemaugh	**3118**	1	1,948.41	1,948.41	0
MANE-VU	**PA**	Conemaugh	**3118**	2	2,441.54	2,441.54	0
MANE-VU	**PA**	Cromby	**3159**	1	0.00	0.00	0
MANE-VU	**PA**	Ebensburg Power Company	**10603**	031	192.64	192.64	0
MANE-VU	**PA**	Eddystone Generating Station	**3161**	1	0.00	0.00	0
MANE-VU	**PA**	Eddystone Generating Station	**3161**	2	0.00	0.00	0
MANE-VU	**PA**	Elrama	**3098**	1	0.00	0.00	0
MANE-VU	**PA**	Elrama	**3098**	2	0.00	0.00	0
MANE-VU	**PA**	Elrama	**3098**	3	0.00	0.00	0
MANE-VU	**PA**	Elrama	**3098**	4	0.00	0.00	0
MANE-VU	**PA**	Gilberton Power Company	**10113**	031	57.72	57.72	0
MANE-VU	**PA**	Gilberton Power Company	**10113**	032	56.80	56.80	0
MANE-VU	**PA**	Hatfields Ferry Power Station	**3179**	1	0.00	0.00	0
MANE-VU	**PA**	Hatfields Ferry Power Station	**3179**	2	0.00	0.00	0
MANE-VU	**PA**	Hatfields Ferry Power Station	**3179**	3	0.00	0.00	0
MANE-VU	**PA**	Homer City	**3122**	1	961.99	679.48	-282.52
MANE-VU	**PA**	Homer City	**3122**	2	960.13	763.43	-196.7
MANE-VU	**PA**	Homer City	**3122**	3	1,633.78	1,253.56	-380.22
MANE-VU	**PA**	Keystone	**3136**	1	2,301.35	1,305.16	-996.2
MANE-VU	**PA**	Keystone	**3136**	2	2,405.67	1,339.26	-1066.4
MANE-VU	**PA**	Mitchell Power Station	**3181**	33	0.00	0.00	0
MANE-VU	**PA**	Montour	**3149**	1	1,581.95	1,028.22	-553.73
MANE-VU	**PA**	Montour	**3149**	2	1,892.79	1,200.83	-691.96
MANE-VU	**PA**	Mt. Carmel Cogeneration	**10343**	SG-101	238.76	238.76	0
MANE-VU	**PA**	New Castle	**3138**	3	42.51	42.51	0
MANE-VU	**PA**	New Castle	**3138**	4	68.66	68.66	0
MANE-VU	**PA**	New Castle	**3138**	5	48.74	48.74	0
MANE-VU	**PA**	Northampton Generating Plant	**50888**	NGC01	267.72	267.72	0
MANE-VU	**PA**	Northeastern Power Company	**50039**	031	83.74	83.74	0
MANE-VU	**PA**	Panther Creek Energy Facility	**50776**	1	171.66	171.66	0
MANE-VU	**PA**	Panther Creek Energy Facility	**50776**	2	158.60	158.60	0
MANE-VU	**PA**	Piney Creek Power Plant	**54144**	031	0.00	0.00	0
MANE-VU	**PA**	Portland	**3113**	1	0.00	0.00	0
MANE-VU	**PA**	Portland	**3113**	2	0.00	0.00	0
MANE-VU	**PA**	Scrubgrass Generating Plant	**50974**	1	226.34	226.34	0
MANE-VU	**PA**	Scrubgrass Generating Plant	**50974**	2	242.52	242.52	0
MANE-VU	**PA**	Seward	**3130**	1	739.24	739.24	0

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
MANE-VU	**PA**	Seward	**3130**	2	673.06	673.06	0
MANE-VU	**PA**	Shawville	**3131**	1	126.85	126.85	0
MANE-VU	**PA**	Shawville	**3131**	2	126.09	126.09	0
MANE-VU	**PA**	Shawville	**3131**	3	198.67	198.67	0
MANE-VU	**PA**	Shawville	**3131**	4	227.60	227.60	0
MANE-VU	**PA**	St. Nicholas Cogeneration Project	**54634**	1	131.46	131.46	0
MANE-VU	**PA**	Sunbury	**3152**	1A	0.00	0.00	0
MANE-VU	**PA**	Sunbury	**3152**	1B	0.00	0.00	0
MANE-VU	**PA**	Sunbury	**3152**	2A	0.00	0.00	0
MANE-VU	**PA**	Sunbury	**3152**	2B	0.00	0.00	0
MANE-VU	**PA**	Sunbury	**3152**	3	0.00	0.00	0
MANE-VU	**PA**	Sunbury	**3152**	4	0.00	0.00	0
MANE-VU	**PA**	Titus	**3115**	1	0.00	0.00	0
MANE-VU	**PA**	Titus	**3115**	2	0.00	0.00	0
MANE-VU	**PA**	Titus	**3115**	3	0.00	0.00	0
MANE-VU	**PA**	Wheelabrator - Frackville	**50879**	GEN1	266.12	266.12	0
MANE-VU	**PA**	WPS Westwood Generation, LLC	**50611**	031	158.44	158.44	0
LADCO	**IL**	Baldwin Energy Complex	**889**	1	0.00	0.00	0
LADCO	**IL**	Baldwin Energy Complex	**889**	2	737.62	653.32	-84.3
LADCO	**IL**	Baldwin Energy Complex	**889**	3	0.00	0.00	0
LADCO	**IL**	Coffeen	**861**	01	321.14	321.14	0
LADCO	**IL**	Coffeen	**861**	02	451.35	451.35	0
LADCO	**IL**	Crawford	**867**	7	0.00	0.00	0
LADCO	**IL**	Crawford	**867**	8	0.00	0.00	0
LADCO	**IL**	Dallman	**963**	31	136.06	136.06	0
LADCO	**IL**	Dallman	**963**	32	102.69	102.69	0
LADCO	**IL**	Dallman	**963**	33	177.83	177.83	0
LADCO	**IL**	Dallman	**963**	4	137.19	137.19	0
LADCO	**IL**	Duck Creek	**6016**	1	611.44	611.44	0
LADCO	**IL**	E D Edwards	**856**	1	0.00	0.00	0
LADCO	**IL**	E D Edwards	**856**	2	1,180.33	1,180.33	0
LADCO	**IL**	E D Edwards	**856**	3	347.71	347.71	0
LADCO	**IL**	Fisk	**886**	19	0.00	0.00	0
LADCO	**IL**	Havana	**891**	9	619.47	619.47	0
LADCO	**IL**	Hennepin Power Station	**892**	1	225.82	225.82	0
LADCO	**IL**	Hennepin Power Station	**892**	2	731.62	731.62	0
LADCO	**IL**	Hutsonville	**863**	05	0.00	0.00	0
LADCO	**IL**	Hutsonville	**863**	06	0.00	0.00	0
LADCO	**IL**	Joppa Steam	**887**	1	507.48	507.48	0
LADCO	**IL**	Joppa Steam	**887**	2	374.69	374.69	0
LADCO	**IL**	Joppa Steam	**887**	3	444.14	444.14	0
LADCO	**IL**	Joppa Steam	**887**	4	454.62	454.62	0
LADCO	**IL**	Joppa Steam	**887**	5	469.43	469.43	0
LADCO	**IL**	Joppa Steam	**887**	6	471.17	471.17	0
LADCO	**IL**	Kincaid Station	**876**	1	648.72	565.41	-83.31
LADCO	**IL**	Kincaid Station	**876**	2	558.30	502.55	-55.75
LADCO	**IL**	Marion	**976**	123	259.12	259.12	0
LADCO	**IL**	Marion	**976**	4	751.29	427.70	-323.59
LADCO	**IL**	Meredosia	**864**	01	0.00	0.00	0
LADCO	**IL**	Meredosia	**864**	02	0.00	0.00	0
LADCO	**IL**	Meredosia	**864**	03	0.00	0.00	0
LADCO	**IL**	Meredosia	**864**	04	0.00	0.00	0
LADCO	**IL**	Meredosia	**864**	05	0.00	0.00	0
LADCO	**IL**	Newton	**6017**	1	1,080.51	1,080.51	0
LADCO	**IL**	Newton	**6017**	2	0.00	0.00	0
LADCO	**IL**	Powerton	**879**	51	993.41	980.85	-12.56
LADCO	**IL**	Powerton	**879**	52	982.20	971.35	-10.86
LADCO	**IL**	Powerton	**879**	61	1,117.32	1,082.17	-35.15
LADCO	**IL**	Powerton	**879**	62	1,137.40	1,017.11	-120.3
LADCO	**IL**	Prairie State Generating Company	**55856**	01	666.89	666.89	0

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
LADCO	IL	Prairie State Generating Company	55856	02	648.72	648.72	0
LADCO	IL	Vermilion Power Station	897	1	0.00	0.00	0
LADCO	IL	Vermilion Power Station	897	2	0.00	0.00	0
LADCO	IL	Waukegan	883	7	583.21	583.21	0
LADCO	IL	Waukegan	883	8	1,004.16	1,004.16	0
LADCO	IL	Will County	884	4	533.73	533.73	0
LADCO	IL	Wood River Power Station	898	4	0.00	0.00	0
LADCO	IL	Wood River Power Station	898	5	0.00	0.00	0
LADCO	IN	A B Brown Generating Station	6137	1	462.13	462.13	0
LADCO	IN	A B Brown Generating Station	6137	2	667.26	667.26	0
LADCO	IN	Alcoa Allowance Management Inc	6705	4	1,129.40	832.93	-296.47
LADCO	IN	Bailly Generating Station	995	7	0.00	0.00	0
LADCO	IN	Bailly Generating Station	995	8	0.00	0.00	0
LADCO	IN	Cayuga	1001	1	2,173.73	2,173.73	0
LADCO	IN	Cayuga	1001	2	2,598.35	2,598.35	0
LADCO	IN	Clifty Creek	983	1	459.99	366.47	-93.52
LADCO	IN	Clifty Creek	983	2	456.71	366.73	-89.98
LADCO	IN	Clifty Creek	983	3	463.41	371.46	-91.96
LADCO	IN	Clifty Creek	983	4	490.57	490.57	0
LADCO	IN	Clifty Creek	983	5	319.32	319.32	0
LADCO	IN	Clifty Creek	983	6	1,765.98	1,765.98	0
LADCO	IN	Edwardsport	1004	7-1	0.00	0.00	0
LADCO	IN	Edwardsport	1004	7-2	0.00	0.00	0
LADCO	IN	Edwardsport	1004	8-1	0.00	0.00	0
LADCO	IN	Edwardsport	1004	CTG1	530.82	530.82	0
LADCO	IN	Edwardsport	1004	CTG2	534.98	534.98	0
LADCO	IN	F B Culley Generating Station	1012	2	61.39	61.39	0
LADCO	IN	F B Culley Generating Station	1012	3	527.25	527.25	0
LADCO	IN	Frank E Ratts	1043	1SG1	0.00	0.00	0
LADCO	IN	Frank E Ratts	1043	2SG1	0.00	0.00	0
LADCO	IN	Gibson	6113	1	1,472.87	844.98	-627.89
LADCO	IN	Gibson	6113	2	1,207.84	739.41	-468.43
LADCO	IN	Gibson	6113	3	1,032.98	584.10	-448.88
LADCO	IN	Gibson	6113	4	1,876.50	1,193.31	-683.19
LADCO	IN	Gibson	6113	5	3,707.17	1,538.64	-2168.53
LADCO	IN	IPL Eagle Valley Generating Station	991	3	0.00	0.00	0
LADCO	IN	IPL Eagle Valley Generating Station	991	4	0.00	0.00	0
LADCO	IN	IPL Eagle Valley Generating Station	991	5	0.00	0.00	0
LADCO	IN	IPL Eagle Valley Generating Station	991	6	0.00	0.00	0
LADCO	IN	Merom	6213	1SG1	1,194.38	1,194.38	0
LADCO	IN	Merom	6213	2SG1	1,278.50	919.54	-358.96
LADCO	IN	Michigan City Generating Station	997	12	1,080.74	974.13	-106.61
LADCO	IN	New Energy Corp	880087	U-4000	0.00	0.00	0
LADCO	IN	Petersburg	994	1	1,088.79	1,088.79	0
LADCO	IN	Petersburg	994	2	1,481.84	837.58	-644.26
LADCO	IN	Petersburg	994	3	1,856.94	1,008.22	-848.72
LADCO	IN	Petersburg	994	4	2,515.96	2,515.96	0
LADCO	IN	R Gallagher	1008	1	0.00	0.00	0
LADCO	IN	R Gallagher	1008	2	0.00	0.00	0
LADCO	IN	R Gallagher	1008	3	0.00	0.00	0
LADCO	IN	R Gallagher	1008	4	0.00	0.00	0
LADCO	IN	R M Schahfer Generating Station	6085	14	757.49	611.71	-145.78
LADCO	IN	R M Schahfer Generating Station	6085	15	1,500.69	1,500.69	0
LADCO	IN	R M Schahfer Generating Station	6085	17	0.00	0.00	0
LADCO	IN	R M Schahfer Generating Station	6085	18	0.00	0.00	0
LADCO	IN	Rockport	6166	MB1	2,684.10	2,684.10	0
LADCO	IN	Rockport	6166	MB2	3,604.33	3,604.33	0
LADCO	IN	State Line Generating Station (IN)	981	3	0.00	0.00	0
LADCO	IN	State Line Generating Station (IN)	981	4	0.00	0.00	0
LADCO	IN	Tanners Creek	988	U1	0.00	0.00	0

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LADCO	**IN**	Tanners Creek	**988**	U2	0.00	0.00	0
LADCO	**IN**	Tanners Creek	**988**	U3	0.00	0.00	0
LADCO	**IN**	Tanners Creek	**988**	U4	0.00	0.00	0
LADCO	**IN**	Wabash River	**1010**	2	0.00	0.00	0
LADCO	**IN**	Wabash River	**1010**	3	0.00	0.00	0
LADCO	**IN**	Wabash River	**1010**	4	0.00	0.00	0
LADCO	**IN**	Wabash River	**1010**	5	0.00	0.00	0
LADCO	**IN**	Wabash River	**1010**	6	0.00	0.00	0
LADCO	**IN**	Whitewater Valley	**1040**	1	84.75	84.75	0
LADCO	**IN**	Whitewater Valley	**1040**	2	168.58	168.58	0
LADCO	**MI**	B C Cobb	**1695**	4	0.00	0.00	0
LADCO	**MI**	B C Cobb	**1695**	5	0.00	0.00	0
LADCO	**MI**	Belle River	**6034**	1	1,722.52	1,722.52	0
LADCO	**MI**	Belle River	**6034**	2	3,564.30	3,564.30	0
LADCO	**MI**	Cadillac Renewable Energy	**54415**	EUBLR	135.04	135.04	0
LADCO	**MI**	Dan E Karn	**1702**	1	314.63	220.75	-93.89
LADCO	**MI**	Dan E Karn	**1702**	2	342.69	238.12	-104.57
LADCO	**MI**	Eckert Station	**1831**	1	0.00	0.00	0
LADCO	**MI**	Eckert Station	**1831**	2	0.00	0.00	0
LADCO	**MI**	Eckert Station	**1831**	3	0.00	0.00	0
LADCO	**MI**	Eckert Station	**1831**	4	0.00	0.00	0
LADCO	**MI**	Eckert Station	**1831**	5	0.00	0.00	0
LADCO	**MI**	Eckert Station	**1831**	6	0.00	0.00	0
LADCO	**MI**	Endicott Generating	**4259**	1	0.00	0.00	0
LADCO	**MI**	Erickson	**1832**	1	755.04	755.04	0
LADCO	**MI**	Genesee Power Station	**54751**	01	76.58	76.58	0
LADCO	**MI**	Grayling Generating Station	**10822**	1	137.56	137.56	0
LADCO	**MI**	Harbor Beach	**1731**	1	0.00	0.00	0
LADCO	**MI**	J B Sims	**1825**	3	235.09	235.09	0
LADCO	**MI**	J C Weadock	**1720**	7	0.00	0.00	0
LADCO	**MI**	J C Weadock	**1720**	8	0.00	0.00	0
LADCO	**MI**	J H Campbell	**1710**	1	636.33	636.33	0
LADCO	**MI**	J H Campbell	**1710**	2	331.71	151.76	-179.95
LADCO	**MI**	J H Campbell	**1710**	3	1,453.42	977.64	-475.78
LADCO	**MI**	J R Whiting	**1723**	1	0.00	0.00	0
LADCO	**MI**	J R Whiting	**1723**	2	0.00	0.00	0
LADCO	**MI**	J R Whiting	**1723**	3	0.00	0.00	0
LADCO	**MI**	James De Young	**1830**	5	0.00	0.00	0
LADCO	**MI**	Monroe	**1733**	1	1,174.93	768.33	-406.6
LADCO	**MI**	Monroe	**1733**	2	1,043.18	1,043.18	0
LADCO	**MI**	Monroe	**1733**	3	590.40	512.56	-77.84
LADCO	**MI**	Monroe	**1733**	4	1,194.84	737.58	-457.26
LADCO	**MI**	Presque Isle	**1769**	5	0.00	0.00	0
LADCO	**MI**	Presque Isle	**1769**	6	0.00	0.00	0
LADCO	**MI**	Presque Isle	**1769**	7	0.00	0.00	0
LADCO	**MI**	Presque Isle	**1769**	8	0.00	0.00	0
LADCO	**MI**	Presque Isle	**1769**	9	0.00	0.00	0
LADCO	**MI**	River Rouge	**1740**	2	0.00	0.00	0
LADCO	**MI**	River Rouge	**1740**	3	0.00	0.00	0
LADCO	**MI**	Shiras	**1843**	3	163.18	163.18	0
LADCO	**MI**	St. Clair	**1743**	1	0.00	0.00	0
LADCO	**MI**	St. Clair	**1743**	2	0.00	0.00	0
LADCO	**MI**	St. Clair	**1743**	3	0.00	0.00	0
LADCO	**MI**	St. Clair	**1743**	4	0.00	0.00	0
LADCO	**MI**	St. Clair	**1743**	6	0.00	0.00	0
LADCO	**MI**	St. Clair	**1743**	7	0.00	0.00	0
LADCO	**MI**	TES Filer City Station	**50835**	1	339.06	339.06	0
LADCO	**MI**	TES Filer City Station	**50835**	2	328.21	328.21	0
LADCO	**MI**	Trenton Channel	**1745**	16	0.00	0.00	0
LADCO	**MI**	Trenton Channel	**1745**	17	0.00	0.00	0

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
LADCO	**MI**	Trenton Channel	**1745**	18	0.00	0.00	0
LADCO	**MI**	Trenton Channel	**1745**	19	0.00	0.00	0
LADCO	**MI**	Trenton Channel	**1745**	9A	0.00	0.00	0
LADCO	**MI**	Wyandotte	**1866**	7	90.20	90.20	0
LADCO	**MI**	Wyandotte	**1866**	8	123.15	123.15	0
LADCO	**MN**	Allen S King	**1915**	1	842.90	842.90	0
LADCO	**MN**	Black Dog	**1904**	3	0.00	0.00	0
LADCO	**MN**	Black Dog	**1904**	4	0.00	0.00	0
LADCO	**MN**	Boswell Energy Center	**1893**	1	0.00	0.00	0
LADCO	**MN**	Boswell Energy Center	**1893**	2	0.00	0.00	0
LADCO	**MN**	Boswell Energy Center	**1893**	3	446.71	446.71	0
LADCO	**MN**	Boswell Energy Center	**1893**	4	1,927.28	1,927.28	0
LADCO	**MN**	Hoot Lake	**1943**	2	0.00	0.00	0
LADCO	**MN**	Hoot Lake	**1943**	3	0.00	0.00	0
LADCO	**MN**	Northeast Station	**1961**	NEPP	0.00	0.00	0
LADCO	**MN**	Sherburne County	**6090**	1	0.00	0.00	0
LADCO	**MN**	Sherburne County	**6090**	2	0.00	0.00	0
LADCO	**MN**	Sherburne County	**6090**	3	1,490.50	1,490.50	0
LADCO	**MN**	Silver Lake	**2008**	4	0.00	0.00	0
LADCO	**MN**	Taconite Harbor Energy Center	**10075**	1	0.00	0.00	0
LADCO	**MN**	Taconite Harbor Energy Center	**10075**	2	0.00	0.00	0
LADCO	**MN**	Taconite Harbor Energy Center	**10075**	3	0.00	0.00	0
LADCO	**OH**	Ashtabula	**2835**	7	0.00	0.00	0
LADCO	**OH**	Avon Lake Power Plant	**2836**	10	6.48	6.48	0
LADCO	**OH**	Avon Lake Power Plant	**2836**	12	2,731.97	1,881.95	-850.02
LADCO	**OH**	Bay Shore	**2878**	1	566.74	566.74	0
LADCO	**OH**	Bay Shore	**2878**	2	0.00	0.00	0
LADCO	**OH**	Bay Shore	**2878**	3	0.00	0.00	0
LADCO	**OH**	Bay Shore	**2878**	4	0.00	0.00	0
LADCO	**OH**	Cardinal	**2828**	1	365.03	251.40	-113.63
LADCO	**OH**	Cardinal	**2828**	2	101.28	99.48	-1.81
LADCO	**OH**	Cardinal	**2828**	3	581.27	222.04	-359.23
LADCO	**OH**	Conesville	**2840**	3	0.00	0.00	0
LADCO	**OH**	Conesville	**2840**	4	676.83	540.88	-135.95
LADCO	**OH**	Conesville	**2840**	5	2,077.04	2,077.04	0
LADCO	**OH**	Conesville	**2840**	6	2,814.95	2,814.95	0
LADCO	**OH**	Eastlake	**2837**	1	0.00	0.00	0
LADCO	**OH**	Eastlake	**2837**	2	0.00	0.00	0
LADCO	**OH**	Eastlake	**2837**	3	0.00	0.00	0
LADCO	**OH**	Eastlake	**2837**	4	0.00	0.00	0
LADCO	**OH**	Eastlake	**2837**	5	0.00	0.00	0
LADCO	**OH**	Gen J M Gavin	**8102**	1	2,464.79	2,259.45	-205.34
LADCO	**OH**	Gen J M Gavin	**8102**	2	2,584.35	2,150.81	-433.53
LADCO	**OH**	Hamilton Municipal Power Plant	**2917**	9	3.90	3.90	0
LADCO	**OH**	J M Stuart	**2850**	1	0.00	0.00	0
LADCO	**OH**	J M Stuart	**2850**	2	0.00	0.00	0
LADCO	**OH**	J M Stuart	**2850**	3	0.00	0.00	0
LADCO	**OH**	J M Stuart	**2850**	4	0.00	0.00	0
LADCO	**OH**	Killen Station	**6031**	2	0.00	0.00	0
LADCO	**OH**	Kyger Creek	**2876**	1	831.43	497.83	-333.6
LADCO	**OH**	Kyger Creek	**2876**	2	821.61	493.75	-327.87
LADCO	**OH**	Kyger Creek	**2876**	3	2,734.85	969.08	-1765.77
LADCO	**OH**	Kyger Creek	**2876**	4	673.73	380.07	-293.66
LADCO	**OH**	Kyger Creek	**2876**	5	2,967.21	1,069.77	-1897.44
LADCO	**OH**	Lake Shore	**2838**	18	0.00	0.00	0
LADCO	**OH**	Miami Fort Generating Station	**2832**	6	0.00	0.00	0
LADCO	**OH**	Miami Fort Generating Station	**2832**	7	2,016.79	1,082.82	-933.97
LADCO	**OH**	Miami Fort Generating Station	**2832**	8	1,552.08	921.27	-630.81
LADCO	**OH**	Muskingum River	**2872**	1	0.00	0.00	0
LADCO	**OH**	Muskingum River	**2872**	2	0.00	0.00	0

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
LADCO	**OH**	Muskingum River	**2872**	3	0.00	0.00	0
LADCO	**OH**	Muskingum River	**2872**	4	0.00	0.00	0
LADCO	**OH**	Muskingum River	**2872**	5	0.00	0.00	0
LADCO	**OH**	Niles	**2861**	1	0.00	0.00	0
LADCO	**OH**	Niles	**2861**	2	0.00	0.00	0
LADCO	**OH**	O H Hutchings	**2848**	H-1	0.00	0.00	0
LADCO	**OH**	O H Hutchings	**2848**	H-2	0.00	0.00	0
LADCO	**OH**	O H Hutchings	**2848**	H-3	0.00	0.00	0
LADCO	**OH**	O H Hutchings	**2848**	H-4	0.00	0.00	0
LADCO	**OH**	O H Hutchings	**2848**	H-5	0.00	0.00	0
LADCO	**OH**	O H Hutchings	**2848**	H-6	0.00	0.00	0
LADCO	**OH**	Picway	**2843**	9	0.00	0.00	0
LADCO	**OH**	R E Burger	**2864**	5	0.00	0.00	0
LADCO	**OH**	R E Burger	**2864**	6	0.00	0.00	0
LADCO	**OH**	W H Sammis	**2866**	1	0.00	0.00	0
LADCO	**OH**	W H Sammis	**2866**	2	0.00	0.00	0
LADCO	**OH**	W H Sammis	**2866**	3	0.00	0.00	0
LADCO	**OH**	W H Sammis	**2866**	4	0.00	0.00	0
LADCO	**OH**	W H Sammis	**2866**	5	515.73	393.68	-122.06
LADCO	**OH**	W H Sammis	**2866**	6	411.49	411.49	0
LADCO	**OH**	W H Sammis	**2866**	7	1,493.46	1,357.04	-136.43
LADCO	**OH**	W H Zimmer Generating Station	**6019**	1	5,798.18	2,060.79	-3737.39
LADCO	**OH**	Walter C Beckjord Generating Station	**2830**	1	0.00	0.00	0
LADCO	**OH**	Walter C Beckjord Generating Station	**2830**	2	0.00	0.00	0
LADCO	**OH**	Walter C Beckjord Generating Station	**2830**	3	0.00	0.00	0
LADCO	**OH**	Walter C Beckjord Generating Station	**2830**	4	0.00	0.00	0
LADCO	**OH**	Walter C Beckjord Generating Station	**2830**	5	0.00	0.00	0
LADCO	**OH**	Walter C Beckjord Generating Station	**2830**	6	0.00	0.00	0
LADCO	**WI**	Alma	**4140**	B4	0.00	0.00	0
LADCO	**WI**	Alma	**4140**	B5	0.00	0.00	0
LADCO	**WI**	Bay Front	**3982**	1	64.30	64.30	0
LADCO	**WI**	Bay Front	**3982**	2	66.57	66.57	0
LADCO	**WI**	Blount Street	**3992**	7	0.00	0.00	0
LADCO	**WI**	Columbia	**8023**	1	1,151.23	1,151.23	0
LADCO	**WI**	Columbia	**8023**	2	694.36	694.36	0
LADCO	**WI**	Edgewater (4050)	**4050**	3	0.00	0.00	0
LADCO	**WI**	Edgewater (4050)	**4050**	5	351.29	261.46	-89.83
LADCO	**WI**	Elm Road Generating Station	**56068**	1	298.11	298.11	0
LADCO	**WI**	Elm Road Generating Station	**56068**	2	482.73	482.73	0
LADCO	**WI**	Genoa	**4143**	1	336.69	336.69	0
LADCO	**WI**	J P Madgett	**4271**	B1	463.11	463.11	0
LADCO	**WI**	Manitowoc	**4125**	8	14.77	14.77	0
LADCO	**WI**	Manitowoc	**4125**	9	87.07	87.07	0
LADCO	**WI**	Nelson Dewey	**4054**	1	0.00	0.00	0
LADCO	**WI**	Nelson Dewey	**4054**	2	0.00	0.00	0
LADCO	**WI**	Pleasant Prairie	**6170**	1	1,084.01	1,084.01	0
LADCO	**WI**	Pleasant Prairie	**6170**	2	653.60	653.60	0
LADCO	**WI**	Pulliam	**4072**	5	0.00	0.00	0
LADCO	**WI**	Pulliam	**4072**	6	0.00	0.00	0
LADCO	**WI**	Pulliam	**4072**	7	170.88	170.88	0
LADCO	**WI**	Pulliam	**4072**	8	433.42	433.42	0
LADCO	**WI**	South Oak Creek	**4041**	5	309.21	309.21	0
LADCO	**WI**	South Oak Creek	**4041**	6	295.56	295.56	0
LADCO	**WI**	South Oak Creek	**4041**	7	351.32	343.58	-7.74
LADCO	**WI**	South Oak Creek	**4041**	8	440.28	432.99	-7.29
LADCO	**WI**	Weston	**4078**	1	0.00	0.00	0
LADCO	**WI**	Weston	**4078**	3	559.48	559.48	0
LADCO	**WI**	Weston	**4078**	4	527.84	527.84	0
SESARM	**AL**	Barry	**3**	3	0.00	0.00	0
SESARM	**AL**	Barry	**3**	4	548.04	548.04	0

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
SESARM	**AL**	Barry	**3**	5	389.58	389.58	0
SESARM	**AL**	Charles R Lowman	**56**	1	266.75	266.75	0
SESARM	**AL**	Charles R Lowman	**56**	2	1,560.89	1,560.89	0
SESARM	**AL**	Charles R Lowman	**56**	3	346.75	346.75	0
SESARM	**AL**	Colbert	**47**	1	0.00	0.00	0
SESARM	**AL**	Colbert	**47**	2	0.00	0.00	0
SESARM	**AL**	Colbert	**47**	3	0.00	0.00	0
SESARM	**AL**	Colbert	**47**	4	0.00	0.00	0
SESARM	**AL**	Colbert	**47**	5	0.00	0.00	0
SESARM	**AL**	E C Gaston	**26**	5	1,727.18	1,213.71	-513.47
SESARM	**AL**	Gorgas	**8**	10	1,892.99	1,892.99	0
SESARM	**AL**	Gorgas	**8**	6	0.00	0.00	0
SESARM	**AL**	Gorgas	**8**	7	0.00	0.00	0
SESARM	**AL**	Gorgas	**8**	8	379.03	379.03	0
SESARM	**AL**	Gorgas	**8**	9	518.57	518.57	0
SESARM	**AL**	James H Miller Jr	**6002**	1	1,620.08	1,620.08	0
SESARM	**AL**	James H Miller Jr	**6002**	2	2,362.07	2,362.07	0
SESARM	**AL**	James H Miller Jr	**6002**	3	2,513.13	2,513.13	0
SESARM	**AL**	James H Miller Jr	**6002**	4	1,372.00	1,372.00	0
SESARM	**AL**	Widows Creek	**50**	1	0.00	0.00	0
SESARM	**AL**	Widows Creek	**50**	2	0.00	0.00	0
SESARM	**AL**	Widows Creek	**50**	3	0.00	0.00	0
SESARM	**AL**	Widows Creek	**50**	4	0.00	0.00	0
SESARM	**AL**	Widows Creek	**50**	5	0.00	0.00	0
SESARM	**AL**	Widows Creek	**50**	6	0.00	0.00	0
SESARM	**AL**	Widows Creek	**50**	7	0.00	0.00	0
SESARM	**AL**	Widows Creek	**50**	8	0.00	0.00	0
SESARM	**FL**	Big Bend	**645**	BB01	729.03	729.03	0
SESARM	**FL**	Big Bend	**645**	BB02	315.63	315.63	0
SESARM	**FL**	Big Bend	**645**	BB03	736.65	736.65	0
SESARM	**FL**	Big Bend	**645**	BB04	731.36	731.36	0
SESARM	**FL**	C D McIntosh Jr Power Plant	**676**	3	593.71	593.71	0
SESARM	**FL**	Cedar Bay Generating Co.	**10672**	CBA	0.00	0.00	0
SESARM	**FL**	Cedar Bay Generating Co.	**10672**	CBB	0.00	0.00	0
SESARM	**FL**	Cedar Bay Generating Co.	**10672**	CBC	0.00	0.00	0
SESARM	**FL**	Crist Electric Generating Plant	**641**	4	0.00	0.00	0
SESARM	**FL**	Crist Electric Generating Plant	**641**	5	0.00	0.00	0
SESARM	**FL**	Crist Electric Generating Plant	**641**	6	192.60	192.60	0
SESARM	**FL**	Crist Electric Generating Plant	**641**	7	1,242.66	1,242.66	0
SESARM	**FL**	Crystal River	**628**	1	0.00	0.00	0
SESARM	**FL**	Crystal River	**628**	2	0.00	0.00	0
SESARM	**FL**	Crystal River	**628**	4	522.10	522.10	0
SESARM	**FL**	Crystal River	**628**	5	675.09	675.09	0
SESARM	**FL**	Curtis H. Stanton Energy Center	**564**	1	1,531.30	1,531.30	0
SESARM	**FL**	Curtis H. Stanton Energy Center	**564**	2	1,128.11	1,128.11	0
SESARM	**FL**	Deerhaven	**663**	B2	160.85	160.85	0
SESARM	**FL**	Indiantown Cogeneration Facility	**50976**	01	528.35	528.35	0
SESARM	**FL**	Lansing Smith Generating Plant	**643**	1	0.00	0.00	0
SESARM	**FL**	Lansing Smith Generating Plant	**643**	2	0.00	0.00	0
SESARM	**FL**	Northside	**667**	1A	120.73	120.73	0
SESARM	**FL**	Northside	**667**	2A	190.12	190.12	0
SESARM	**FL**	Polk	**7242**	**1	218.08	218.08	0
SESARM	**FL**	Scholz Electric Generating Plant	**642**	1	0.00	0.00	0
SESARM	**FL**	Scholz Electric Generating Plant	**642**	2	0.00	0.00	0
SESARM	**FL**	Seminole (136)	**136**	1	614.96	614.96	0
SESARM	**FL**	Seminole (136)	**136**	2	622.70	622.70	0
SESARM	**FL**	St. Johns River Power	**207**	1	0.00	0.00	0
SESARM	**FL**	St. Johns River Power	**207**	2	0.00	0.00	0
SESARM	**GA**	Bowen	**703**	1BLR	2,128.78	1,104.38	-1024.41
SESARM	**GA**	Bowen	**703**	2BLR	1,365.23	867.92	-497.32

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
SESARM	**GA**	Bowen	**703**	3BLR	960.53	594.27	-366.26
SESARM	**GA**	Bowen	**703**	4BLR	1,301.04	671.24	-629.8
SESARM	**GA**	Hammond	**708**	1	142.46	142.46	0
SESARM	**GA**	Hammond	**708**	2	220.14	220.14	0
SESARM	**GA**	Hammond	**708**	3	143.18	143.18	0
SESARM	**GA**	Hammond	**708**	4	1,146.75	1,146.75	0
SESARM	**GA**	Harllee Branch	**709**	1	0.00	0.00	0
SESARM	**GA**	Harllee Branch	**709**	2	0.00	0.00	0
SESARM	**GA**	Harllee Branch	**709**	3	0.00	0.00	0
SESARM	**GA**	Harllee Branch	**709**	4	0.00	0.00	0
SESARM	**GA**	Jack McDonough	**710**	MB1	0.00	0.00	0
SESARM	**GA**	Jack McDonough	**710**	MB2	0.00	0.00	0
SESARM	**GA**	Kraft	**733**	1	0.00	0.00	0
SESARM	**GA**	Kraft	**733**	2	0.00	0.00	0
SESARM	**GA**	Kraft	**733**	3	0.00	0.00	0
SESARM	**GA**	McIntosh (6124)	**6124**	1	61.18	61.18	0
SESARM	**GA**	Mitchell (GA)	**727**	3	0.00	0.00	0
SESARM	**GA**	Scherer	**6257**	1	2,233.25	809.96	-1423.29
SESARM	**GA**	Scherer	**6257**	2	2,316.44	1,429.08	-887.37
SESARM	**GA**	Scherer	**6257**	3	4,010.14	4,010.14	0
SESARM	**GA**	Scherer	**6257**	4	3,743.59	1,842.06	-1901.54
SESARM	**GA**	Wansley (6052)	**6052**	1	779.43	779.43	0
SESARM	**GA**	Wansley (6052)	**6052**	2	457.62	457.62	0
SESARM	**GA**	Yates	**728**	Y1BR	0.00	0.00	0
SESARM	**GA**	Yates	**728**	Y2BR	0.00	0.00	0
SESARM	**GA**	Yates	**728**	Y3BR	0.00	0.00	0
SESARM	**GA**	Yates	**728**	Y4BR	0.00	0.00	0
SESARM	**GA**	Yates	**728**	Y5BR	0.00	0.00	0
SESARM	**KY**	Big Sandy	**1353**	BSU2	0.00	0.00	0
SESARM	**KY**	Cane Run	**1363**	4	0.00	0.00	0
SESARM	**KY**	Cane Run	**1363**	5	0.00	0.00	0
SESARM	**KY**	Cane Run	**1363**	6	0.00	0.00	0
SESARM	**KY**	Coleman	**1381**	C1	0.00	0.00	0
SESARM	**KY**	Coleman	**1381**	C2	0.00	0.00	0
SESARM	**KY**	Coleman	**1381**	C3	0.00	0.00	0
SESARM	**KY**	D B Wilson	**6823**	W1	730.79	576.71	-154.07
SESARM	**KY**	E W Brown	**1355**	1	404.86	404.86	0
SESARM	**KY**	E W Brown	**1355**	2	709.79	709.79	0
SESARM	**KY**	E W Brown	**1355**	3	336.91	336.91	0
SESARM	**KY**	East Bend	**6018**	2	1,900.01	1,168.54	-731.47
SESARM	**KY**	Elmer Smith	**1374**	1	0.00	0.00	0
SESARM	**KY**	Elmer Smith	**1374**	2	0.00	0.00	0
SESARM	**KY**	Ghent	**1356**	1	985.80	696.23	-289.57
SESARM	**KY**	Ghent	**1356**	2	2,078.51	2,078.51	0
SESARM	**KY**	Ghent	**1356**	3	1,362.77	685.59	-677.18
SESARM	**KY**	Ghent	**1356**	4	746.53	400.64	-345.9
SESARM	**KY**	Green River	**1357**	4	0.00	0.00	0
SESARM	**KY**	Green River	**1357**	5	0.00	0.00	0
SESARM	**KY**	H L Spurlock	**6041**	1	495.17	453.13	-42.04
SESARM	**KY**	H L Spurlock	**6041**	2	972.64	904.88	-67.76
SESARM	**KY**	H L Spurlock	**6041**	3	436.73	436.73	0
SESARM	**KY**	H L Spurlock	**6041**	4	440.94	440.94	0
SESARM	**KY**	HMP&L Station 2	**1382**	H1	307.74	307.74	0
SESARM	**KY**	HMP&L Station 2	**1382**	H2	303.49	303.49	0
SESARM	**KY**	John S. Cooper	**1384**	1	883.13	883.13	0
SESARM	**KY**	John S. Cooper	**1384**	2	173.66	173.66	0
SESARM	**KY**	Mill Creek	**1364**	1	2,059.20	2,059.20	0
SESARM	**KY**	Mill Creek	**1364**	2	2,189.94	2,189.94	0
SESARM	**KY**	Mill Creek	**1364**	3	374.33	337.71	-36.62
SESARM	**KY**	Mill Creek	**1364**	4	1,152.91	670.94	-481.96

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
SESARM	**KY**	Paradise	**1378**	1	0.00	0.00	0
SESARM	**KY**	Paradise	**1378**	2	0.00	0.00	0
SESARM	**KY**	Paradise	**1378**	3	2,227.15	1,600.97	-626.17
SESARM	**KY**	R D Green	**6639**	G1	1,391.02	1,391.02	0
SESARM	**KY**	R D Green	**6639**	G2	1,224.61	1,224.61	0
SESARM	**KY**	Robert Reid	**1383**	R1	0.00	0.00	0
SESARM	**KY**	Shawnee	**1379**	1	116.82	116.82	0
SESARM	**KY**	Shawnee	**1379**	10	0.00	0.00	0
SESARM	**KY**	Shawnee	**1379**	2	1,181.67	1,181.67	0
SESARM	**KY**	Shawnee	**1379**	3	1,181.41	1,181.41	0
SESARM	**KY**	Shawnee	**1379**	4	115.42	115.42	0
SESARM	**KY**	Shawnee	**1379**	5	1,313.23	1,313.23	0
SESARM	**KY**	Shawnee	**1379**	6	931.73	931.73	0
SESARM	**KY**	Shawnee	**1379**	7	1,007.34	1,007.34	0
SESARM	**KY**	Shawnee	**1379**	8	987.06	987.06	0
SESARM	**KY**	Shawnee	**1379**	9	882.42	882.42	0
SESARM	**KY**	Trimble County	**6071**	1	725.31	725.31	0
SESARM	**KY**	Trimble County	**6071**	2	633.49	633.49	0
SESARM	**KY**	Tyrone	**1361**	5	0.00	0.00	0
SESARM	**KY**	William C. Dale	**1385**	1	0.00	0.00	0
SESARM	**KY**	William C. Dale	**1385**	2	0.00	0.00	0
SESARM	**KY**	William C. Dale	**1385**	3	0.00	0.00	0
SESARM	**KY**	William C. Dale	**1385**	4	0.00	0.00	0
SESARM	**MS**	Daniel Electric Generating Plant	**6073**	1	984.49	984.49	0
SESARM	**MS**	Daniel Electric Generating Plant	**6073**	2	377.10	377.10	0
SESARM	**MS**	R D Morrow Senior Generating Plant	**6061**	1	848.49	848.49	0
SESARM	**MS**	R D Morrow Senior Generating Plant	**6061**	2	1,170.65	1,170.65	0
SESARM	**MS**	Red Hills Generation Facility	**55076**	AA001	560.95	560.95	0
SESARM	**MS**	Red Hills Generation Facility	**55076**	AA002	738.52	738.52	0
SESARM	**NC**	Asheville	**2706**	1	0.00	0.00	0
SESARM	**NC**	Asheville	**2706**	2	0.00	0.00	0
SESARM	**NC**	Belews Creek	**8042**	1	1,343.74	1,343.74	0
SESARM	**NC**	Belews Creek	**8042**	2	1,380.02	770.66	-609.36
SESARM	**NC**	Buck	**2720**	5	0.00	0.00	0
SESARM	**NC**	Buck	**2720**	6	0.00	0.00	0
SESARM	**NC**	Buck	**2720**	7	0.00	0.00	0
SESARM	**NC**	Buck	**2720**	8	0.00	0.00	0
SESARM	**NC**	Buck	**2720**	9	0.00	0.00	0
SESARM	**NC**	Cape Fear	**2708**	5	0.00	0.00	0
SESARM	**NC**	Cape Fear	**2708**	6	0.00	0.00	0
SESARM	**NC**	Cliffside	**2721**	1	0.00	0.00	0
SESARM	**NC**	Cliffside	**2721**	2	0.00	0.00	0
SESARM	**NC**	Cliffside	**2721**	3	0.00	0.00	0
SESARM	**NC**	Cliffside	**2721**	4	0.00	0.00	0
SESARM	**NC**	Cliffside	**2721**	5	249.50	90.73	-158.77
SESARM	**NC**	Cliffside	**2721**	6	698.96	698.96	0
SESARM	**NC**	Dan River	**2723**	1	0.00	0.00	0
SESARM	**NC**	Dan River	**2723**	2	0.00	0.00	0
SESARM	**NC**	Dan River	**2723**	3	0.00	0.00	0
SESARM	**NC**	Elizabethtown Power	**10380**	UNIT1	0.00	0.00	0
SESARM	**NC**	Elizabethtown Power	**10380**	UNIT2	0.00	0.00	0
SESARM	**NC**	G G Allen	**2718**	1	0.00	0.00	0
SESARM	**NC**	G G Allen	**2718**	2	0.00	0.00	0
SESARM	**NC**	G G Allen	**2718**	3	0.00	0.00	0
SESARM	**NC**	G G Allen	**2718**	4	176.36	176.36	0
SESARM	**NC**	G G Allen	**2718**	5	157.85	157.85	0
SESARM	**NC**	H F Lee Steam Electric Plant	**2709**	1	0.00	0.00	0
SESARM	**NC**	H F Lee Steam Electric Plant	**2709**	2	0.00	0.00	0
SESARM	**NC**	H F Lee Steam Electric Plant	**2709**	3	0.00	0.00	0
SESARM	**NC**	L V Sutton	**2713**	1	0.00	0.00	0

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
SESARM	**NC**	L V Sutton	**2713**	2	0.00	0.00	0
SESARM	**NC**	L V Sutton	**2713**	3	0.00	0.00	0
SESARM	**NC**	Lumberton Power	**10382**	UNIT1	0.00	0.00	0
SESARM	**NC**	Lumberton Power	**10382**	UNIT2	0.00	0.00	0
SESARM	**NC**	Marshall	**2727**	1	426.84	327.46	-99.38
SESARM	**NC**	Marshall	**2727**	2	662.70	530.22	-132.49
SESARM	**NC**	Marshall	**2727**	3	834.09	546.09	-288
SESARM	**NC**	Marshall	**2727**	4	1,707.68	1,366.79	-340.89
SESARM	**NC**	Mayo	**6250**	1A	357.36	186.40	-170.95
SESARM	**NC**	Mayo	**6250**	1B	323.74	167.64	-156.1
SESARM	**NC**	Riverbend	**2732**	10	0.00	0.00	0
SESARM	**NC**	Riverbend	**2732**	7	0.00	0.00	0
SESARM	**NC**	Riverbend	**2732**	8	0.00	0.00	0
SESARM	**NC**	Riverbend	**2732**	9	0.00	0.00	0
SESARM	**NC**	Roxboro	**2712**	1	398.83	235.36	-163.48
SESARM	**NC**	Roxboro	**2712**	2	570.97	416.97	-154
SESARM	**NC**	Roxboro	**2712**	3A	393.88	211.22	-182.67
SESARM	**NC**	Roxboro	**2712**	3B	368.67	195.42	-173.24
SESARM	**NC**	Roxboro	**2712**	4A	309.60	211.16	-98.44
SESARM	**NC**	Roxboro	**2712**	4B	279.95	189.31	-90.64
SESARM	**NC**	W H Weatherspoon	**2716**	1	0.00	0.00	0
SESARM	**NC**	W H Weatherspoon	**2716**	2	0.00	0.00	0
SESARM	**NC**	W H Weatherspoon	**2716**	3	0.00	0.00	0
SESARM	**NC**	Westmoreland Partners Roanoke Valley II	**54755**	2	45.55	45.55	0
SESARM	**NC**	Westmoreland-LG&E Roanoke Valley I	**54035**	1	217.14	217.14	0
SESARM	**SC**	Canadys Steam	**3280**	CAN1	0.00	0.00	0
SESARM	**SC**	Canadys Steam	**3280**	CAN2	0.00	0.00	0
SESARM	**SC**	Canadys Steam	**3280**	CAN3	0.00	0.00	0
SESARM	**SC**	Cope Station	**7210**	COP1	295.14	295.14	0
SESARM	**SC**	Cross	**130**	1	868.88	868.88	0
SESARM	**SC**	Cross	**130**	2	0.00	0.00	0
SESARM	**SC**	Cross	**130**	3	390.09	390.09	0
SESARM	**SC**	Cross	**130**	4	367.77	367.77	0
SESARM	**SC**	Dolphus M Grainger	**3317**	1	0.00	0.00	0
SESARM	**SC**	Dolphus M Grainger	**3317**	2	0.00	0.00	0
SESARM	**SC**	H B Robinson	**3251**	1	0.00	0.00	0
SESARM	**SC**	Jefferies	**3319**	3	0.00	0.00	0
SESARM	**SC**	Jefferies	**3319**	4	0.00	0.00	0
SESARM	**SC**	W S Lee	**3264**	1	0.00	0.00	0
SESARM	**SC**	W S Lee	**3264**	2	0.00	0.00	0
SESARM	**SC**	Wateree	**3297**	WAT1	306.91	184.37	-122.54
SESARM	**SC**	Wateree	**3297**	WAT2	297.80	190.26	-107.54
SESARM	**SC**	Williams	**3298**	WIL1	418.33	205.25	-213.09
SESARM	**SC**	Winyah	**6249**	1	215.45	155.75	-59.69
SESARM	**SC**	Winyah	**6249**	2	185.63	129.88	-55.75
SESARM	**SC**	Winyah	**6249**	3	181.78	156.98	-24.8
SESARM	**SC**	Winyah	**6249**	4	224.99	190.11	-34.88
SESARM	**TN**	Allen	**3393**	1	0.00	0.00	0
SESARM	**TN**	Allen	**3393**	2	0.00	0.00	0
SESARM	**TN**	Allen	**3393**	3	0.00	0.00	0
SESARM	**TN**	Bull Run	**3396**	1	174.44	174.44	0
SESARM	**TN**	Cumberland	**3399**	1	977.10	931.44	-45.66
SESARM	**TN**	Cumberland	**3399**	2	1,802.96	1,802.96	0
SESARM	**TN**	Gallatin	**3403**	1	166.83	166.83	0
SESARM	**TN**	Gallatin	**3403**	2	163.78	163.78	0
SESARM	**TN**	Gallatin	**3403**	3	199.77	199.77	0
SESARM	**TN**	Gallatin	**3403**	4	201.21	201.21	0
SESARM	**TN**	John Sevier	**3405**	1	0.00	0.00	0
SESARM	**TN**	John Sevier	**3405**	2	0.00	0.00	0
SESARM	**TN**	John Sevier	**3405**	3	0.00	0.00	0

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
SESARM	**TN**	John Sevier	**3405**	4	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	1	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	10	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	2	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	3	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	4	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	5	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	6	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	7	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	8	0.00	0.00	0
SESARM	**TN**	Johnsonville	**3406**	9	0.00	0.00	0
SESARM	**TN**	Kingston	**3407**	1	118.81	86.41	-32.4
SESARM	**TN**	Kingston	**3407**	2	50.75	41.21	-9.54
SESARM	**TN**	Kingston	**3407**	3	114.09	84.22	-29.86
SESARM	**TN**	Kingston	**3407**	4	112.40	88.25	-24.15
SESARM	**TN**	Kingston	**3407**	5	103.17	81.74	-21.43
SESARM	**TN**	Kingston	**3407**	6	46.43	37.19	-9.24
SESARM	**TN**	Kingston	**3407**	7	89.64	67.50	-22.14
SESARM	**TN**	Kingston	**3407**	8	45.47	36.96	-8.52
SESARM	**TN**	Kingston	**3407**	9	79.33	60.48	-18.85
SESARM	**VA**	Altavista Power Station	**10773**	1	0.00	0.00	0
SESARM	**VA**	Altavista Power Station	**10773**	2	0.00	0.00	0
SESARM	**VA**	Birchwood Power Facility	**54304**	001	79.66	79.66	0
SESARM	**VA**	Chesapeake Energy Center	**3803**	1	0.00	0.00	0
SESARM	**VA**	Chesapeake Energy Center	**3803**	2	0.00	0.00	0
SESARM	**VA**	Chesapeake Energy Center	**3803**	3	0.00	0.00	0
SESARM	**VA**	Chesapeake Energy Center	**3803**	4	0.00	0.00	0
SESARM	**VA**	Chesterfield Power Station	**3797**	3	95.37	95.37	0
SESARM	**VA**	Chesterfield Power Station	**3797**	4	87.54	44.17	-43.37
SESARM	**VA**	Chesterfield Power Station	**3797**	5	135.42	68.75	-66.67
SESARM	**VA**	Chesterfield Power Station	**3797**	6	253.58	155.69	-97.9
SESARM	**VA**	Clinch River	**3775**	3	0.00	0.00	0
SESARM	**VA**	Clover Power Station	**7213**	1	1,322.05	1,322.05	0
SESARM	**VA**	Clover Power Station	**7213**	2	1,401.33	1,401.33	0
SESARM	**VA**	Cogentrix-Hopewell	**10377**	BLR01A	75.41	75.41	0
SESARM	**VA**	Cogentrix-Hopewell	**10377**	BLR01B	57.17	57.17	0
SESARM	**VA**	Cogentrix-Hopewell	**10377**	BLR01C	74.40	74.40	0
SESARM	**VA**	Cogentrix-Hopewell	**10377**	BLR02A	65.68	65.68	0
SESARM	**VA**	Cogentrix-Hopewell	**10377**	BLR02B	45.00	45.00	0
SESARM	**VA**	Cogentrix-Hopewell	**10377**	BLR02C	44.80	44.80	0
SESARM	**VA**	Cogentrix-Portsmouth	**10071**	BLR01A	0.00	0.00	0
SESARM	**VA**	Cogentrix-Portsmouth	**10071**	BLR01B	0.00	0.00	0
SESARM	**VA**	Cogentrix-Portsmouth	**10071**	BLR01C	0.00	0.00	0
SESARM	**VA**	Cogentrix-Portsmouth	**10071**	BLR02A	0.00	0.00	0
SESARM	**VA**	Cogentrix-Portsmouth	**10071**	BLR02B	0.00	0.00	0
SESARM	**VA**	Cogentrix-Portsmouth	**10071**	BLR02C	0.00	0.00	0
SESARM	**VA**	Glen Lyn	**3776**	51	0.00	0.00	0
SESARM	**VA**	Glen Lyn	**3776**	52	0.00	0.00	0
SESARM	**VA**	Glen Lyn	**3776**	6	0.00	0.00	0
SESARM	**VA**	Hopewell Power Station	**10771**	1	0.00	0.00	0
SESARM	**VA**	Hopewell Power Station	**10771**	2	0.00	0.00	0
SESARM	**VA**	Mecklenburg Power Station	**52007**	1	52.71	52.71	0
SESARM	**VA**	Mecklenburg Power Station	**52007**	2	55.98	55.98	0
SESARM	**VA**	Mirant Potomac River	**3788**	1	0.00	0.00	0
SESARM	**VA**	Mirant Potomac River	**3788**	2	0.00	0.00	0
SESARM	**VA**	Mirant Potomac River	**3788**	3	0.00	0.00	0
SESARM	**VA**	Mirant Potomac River	**3788**	4	0.00	0.00	0
SESARM	**VA**	Mirant Potomac River	**3788**	5	0.00	0.00	0
SESARM	**VA**	Southampton Power Station	**10774**	1	0.00	0.00	0
SESARM	**VA**	Southampton Power Station	**10774**	2	0.00	0.00	0

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
SESARM	**VA**	Spruance Genco, LLC	**54081**	BLR01A	109.61	109.61	0
SESARM	**VA**	Spruance Genco, LLC	**54081**	BLR01B	118.07	118.07	0
SESARM	**VA**	Spruance Genco, LLC	**54081**	BLR02A	119.63	119.63	0
SESARM	**VA**	Spruance Genco, LLC	**54081**	BLR02B	118.16	118.16	0
SESARM	**VA**	Spruance Genco, LLC	**54081**	BLR03A	116.16	116.16	0
SESARM	**VA**	Spruance Genco, LLC	**54081**	BLR03B	118.66	118.66	0
SESARM	**VA**	Spruance Genco, LLC	**54081**	BLR04A	98.24	98.24	0
SESARM	**VA**	Spruance Genco, LLC	**54081**	BLR04B	93.34	93.34	0
SESARM	**VA**	Virginia City Hybrid Energy Center	**56808**	1	453.23	453.23	0
SESARM	**VA**	Virginia City Hybrid Energy Center	**56808**	2	419.44	419.44	0
SESARM	**VA**	Yorktown Power Station	**3809**	1	0.00	0.00	0
SESARM	**VA**	Yorktown Power Station	**3809**	2	0.00	0.00	0
SESARM	**WV**	Albright Power Station	**3942**	1	0.00	0.00	0
SESARM	**WV**	Albright Power Station	**3942**	2	0.00	0.00	0
SESARM	**WV**	Albright Power Station	**3942**	3	0.00	0.00	0
SESARM	**WV**	Fort Martin Power Station	**3943**	1	3,856.71	3,856.71	0
SESARM	**WV**	Fort Martin Power Station	**3943**	2	3,964.71	3,964.71	0
SESARM	**WV**	Grant Town Power Plant	**10151**	1A	497.46	497.46	0
SESARM	**WV**	Grant Town Power Plant	**10151**	1B	488.67	488.67	0
SESARM	**WV**	Harrison Power Station	**3944**	1	3,275.75	1,438.23	-1837.52
SESARM	**WV**	Harrison Power Station	**3944**	2	3,299.07	1,272.83	-2026.23
SESARM	**WV**	Harrison Power Station	**3944**	3	3,266.44	3,266.44	0
SESARM	**WV**	John E Amos	**3935**	1	750.57	564.25	-186.32
SESARM	**WV**	John E Amos	**3935**	2	856.52	584.34	-272.18
SESARM	**WV**	John E Amos	**3935**	3	1,022.68	1,022.68	0
SESARM	**WV**	Kammer	**3947**	1	0.00	0.00	0
SESARM	**WV**	Kammer	**3947**	2	0.00	0.00	0
SESARM	**WV**	Kammer	**3947**	3	0.00	0.00	0
SESARM	**WV**	Kanawha River	**3936**	1	0.00	0.00	0
SESARM	**WV**	Kanawha River	**3936**	2	0.00	0.00	0
SESARM	**WV**	Longview Power	**56671**	001	915.48	915.48	0
SESARM	**WV**	Mitchell (WV)	**3948**	1	632.15	632.15	0
SESARM	**WV**	Mitchell (WV)	**3948**	2	925.19	925.19	0
SESARM	**WV**	Mount Storm Power Station	**3954**	1	391.08	315.83	-75.25
SESARM	**WV**	Mount Storm Power Station	**3954**	2	324.99	249.11	-75.87
SESARM	**WV**	Mount Storm Power Station	**3954**	3	334.85	334.85	0
SESARM	**WV**	Mountaineer (1301)	**6264**	1	1,421.90	1,052.13	-369.77
SESARM	**WV**	Phil Sporn	**3938**	11	0.00	0.00	0
SESARM	**WV**	Phil Sporn	**3938**	21	0.00	0.00	0
SESARM	**WV**	Phil Sporn	**3938**	31	0.00	0.00	0
SESARM	**WV**	Phil Sporn	**3938**	41	0.00	0.00	0
SESARM	**WV**	Phil Sporn	**3938**	51	0.00	0.00	0
SESARM	**WV**	Pleasants Power Station	**6004**	1	2,311.41	1,131.08	-1180.33
SESARM	**WV**	Pleasants Power Station	**6004**	2	1,795.10	935.11	-859.99
SESARM	**WV**	Rivesville Power Station	**3945**	7	0.00	0.00	0
SESARM	**WV**	Rivesville Power Station	**3945**	8	0.00	0.00	0
SESARM	**WV**	Willow Island Power Station	**3946**	1	0.00	0.00	0
SESARM	**WV**	Willow Island Power Station	**3946**	2	0.00	0.00	0
SESARM	**WV**	Morgantown Energy Associates	**10743**	CFB1	212.05	212.05	0
SESARM	**WV**	Morgantown Energy Associates	**10743**	CFB2	211.03	211.03	0
CENSARA	**AR**	Flint Creek Power Plant	**6138**	1	2,943.88	2,943.88	0
CENSARA	**AR**	Independence	**6641**	1	4,282.36	4,282.36	0
CENSARA	**AR**	Independence	**6641**	2	4,038.27	4,038.27	0
CENSARA	**AR**	John W. Turk Jr. Power Plant	**56564**	SN-01	547.45	547.45	0
CENSARA	**AR**	Plum Point Energy Station	**56456**	1	924.01	924.01	0
CENSARA	**AR**	White Bluff	**6009**	1	3,416.40	3,416.40	0
CENSARA	**AR**	White Bluff	**6009**	2	5,072.31	5,072.31	0
CENSARA	**IA**	Dubuque	**1046**	1	0.00	0.00	0
CENSARA	**IA**	Dubuque	**1046**	5	0.00	0.00	0
CENSARA	**IA**	Dubuque	**1046**	6	0.00	0.00	0

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
CENSARA	**IA**	Fair Station	**1218**	2	0.00	0.00	0
CENSARA	**IA**	George Neal North	**1091**	1	0.00	0.00	0
CENSARA	**IA**	George Neal North	**1091**	2	0.00	0.00	0
CENSARA	**IA**	George Neal North	**1091**	3	1,798.19	1,798.19	0
CENSARA	**IA**	George Neal South	**7343**	4	2,601.58	2,390.56	-211.02
CENSARA	**IA**	Lansing	**1047**	3	0.00	0.00	0
CENSARA	**IA**	Lansing	**1047**	4	261.82	261.82	0
CENSARA	**IA**	Louisa	**6664**	101	1,800.13	1,800.13	0
CENSARA	**IA**	Muscatine	**1167**	8	1,581.79	1,581.79	0
CENSARA	**IA**	Muscatine	**1167**	9	297.99	297.99	0
CENSARA	**IA**	Ottumwa	**6254**	1	744.55	744.55	0
CENSARA	**IA**	Pella	**1175**	6	0.00	0.00	0
CENSARA	**IA**	Pella	**1175**	7	0.00	0.00	0
CENSARA	**IA**	Sutherland	**1077**	1	0.00	0.00	0
CENSARA	**IA**	Sutherland	**1077**	3	0.00	0.00	0
CENSARA	**IA**	Walter Scott Jr. Energy Center	**1082**	1	0.00	0.00	0
CENSARA	**IA**	Walter Scott Jr. Energy Center	**1082**	2	0.00	0.00	0
CENSARA	**IA**	Walter Scott Jr. Energy Center	**1082**	3	3,252.00	3,252.00	0
CENSARA	**IA**	Walter Scott Jr. Energy Center	**1082**	4	782.32	782.32	0
CENSARA	**KS**	Holcomb	**108**	SGU1	1,321.80	1,321.80	0
CENSARA	**KS**	Jeffrey Energy Center	**6068**	1	1,271.87	1,271.87	0
CENSARA	**KS**	Jeffrey Energy Center	**6068**	2	1,345.42	1,345.42	0
CENSARA	**KS**	Jeffrey Energy Center	**6068**	3	2,001.34	2,001.34	0
CENSARA	**KS**	La Cygne	**1241**	1	978.56	863.75	-114.81
CENSARA	**KS**	La Cygne	**1241**	2	3,729.42	1,955.61	-1773.81
CENSARA	**KS**	Lawrence Energy Center	**1250**	3	0.00	0.00	0
CENSARA	**KS**	Lawrence Energy Center	**1250**	4	417.12	417.12	0
CENSARA	**KS**	Lawrence Energy Center	**1250**	5	1,242.41	1,242.41	0
CENSARA	**KS**	Nearman Creek	**6064**	N1	1,527.45	1,527.45	0
CENSARA	**KS**	Riverton	**1239**	39	0.00	0.00	0
CENSARA	**KS**	Riverton	**1239**	40	0.00	0.00	0
CENSARA	**KS**	Tecumseh Energy Center	**1252**	10	0.00	0.00	0
CENSARA	**KS**	Tecumseh Energy Center	**1252**	9	237.74	237.74	0
CENSARA	**LA**	Big Cajun 2	**6055**	2B1	688.93	688.93	0
CENSARA	**LA**	Dolet Hills Power Station	**51**	1	2,775.43	2,775.43	0
CENSARA	**LA**	Nelson Industrial Steam Company	**50030**	1A	439.98	439.98	0
CENSARA	**LA**	Nelson Industrial Steam Company	**50030**	2A	438.61	438.61	0
CENSARA	**LA**	R S Nelson	**1393**	6	1,976.99	1,976.99	0
CENSARA	**LA**	Rodemacher Power Station (6190)	**6190**	2	1,302.62	1,302.62	0
CENSARA	**LA**	Rodemacher Power Station (6190)	**6190**	3-1	196.84	196.84	0
CENSARA	**LA**	Rodemacher Power Station (6190)	**6190**	3-2	256.72	256.72	0
CENSARA	**MO**	Asbury	**2076**	1	1,503.01	1,503.01	0
CENSARA	**MO**	Chamois Power Plant	**2169**	2	0.00	0.00	0
CENSARA	**MO**	Columbia	**2123**	6	60.53	60.53	0
CENSARA	**MO**	Columbia	**2123**	7	76.89	76.89	0
CENSARA	**MO**	Hawthorn	**2079**	5A	782.88	782.88	0
CENSARA	**MO**	Iatan	**6065**	1	836.76	836.76	0
CENSARA	**MO**	Iatan	**6065**	2	674.93	674.93	0
CENSARA	**MO**	John Twitty Energy Center	**6195**	1	333.36	333.36	0
CENSARA	**MO**	John Twitty Energy Center	**6195**	2	407.37	407.37	0
CENSARA	**MO**	Labadie	**2103**	1	1,334.89	1,334.89	0
CENSARA	**MO**	Labadie	**2103**	2	1,464.99	1,464.99	0
CENSARA	**MO**	Labadie	**2103**	3	1,386.43	1,386.43	0
CENSARA	**MO**	Labadie	**2103**	4	1,495.00	1,495.00	0
CENSARA	**MO**	Lake Road	**2098**	6	0.00	0.00	0
CENSARA	**MO**	Meramec	**2104**	1	0.00	0.00	0
CENSARA	**MO**	Meramec	**2104**	2	0.00	0.00	0
CENSARA	**MO**	Meramec	**2104**	3	0.00	0.00	0
CENSARA	**MO**	Meramec	**2104**	4	0.00	0.00	0
CENSARA	**MO**	Montrose	**2080**	1	0.00	0.00	0

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
CENSARA	**MO**	New Madrid Power Plant	**2167**	1	1,852.79	1,302.74	-550.04
CENSARA	**MO**	New Madrid Power Plant	**2167**	2	1,412.25	831.80	-580.45
CENSARA	**MO**	Rush Island	**6155**	1	913.29	913.29	0
CENSARA	**MO**	Rush Island	**6155**	2	1,063.91	1,063.91	0
CENSARA	**MO**	Sibley	**2094**	3	0.00	0.00	0
CENSARA	**MO**	Sikeston	**6768**	1	1,283.04	831.71	-451.33
CENSARA	**MO**	Sioux	**2107**	1	1,347.62	1,347.62	0
CENSARA	**MO**	Sioux	**2107**	2	1,943.83	1,943.83	0
CENSARA	**MO**	Thomas Hill Energy Center	**2168**	MB1	595.07	595.07	0
CENSARA	**MO**	Thomas Hill Energy Center	**2168**	MB2	685.26	685.26	0
CENSARA	**MO**	Thomas Hill Energy Center	**2168**	MB3	2,238.46	1,842.51	-395.95
CENSARA	**NE**	Gerald Gentleman Station	**6077**	1	3,058.78	3,058.78	0
CENSARA	**NE**	Gerald Gentleman Station	**6077**	2	5,487.51	5,487.51	0
CENSARA	**NE**	Gerald Whelan Energy Center	**60**	1	561.32	561.32	0
CENSARA	**NE**	Gerald Whelan Energy Center	**60**	2	137.36	137.36	0
CENSARA	**NE**	Lon D Wright Power Plant	**2240**	8	268.93	268.93	0
CENSARA	**NE**	Nebraska City Station	**6096**	1	2,879.47	2,879.47	0
CENSARA	**NE**	Nebraska City Station	**6096**	2	867.72	867.72	0
CENSARA	**NE**	North Omaha Station	**2291**	1	515.34	515.34	0
CENSARA	**NE**	North Omaha Station	**2291**	2	560.14	560.14	0
CENSARA	**NE**	North Omaha Station	**2291**	3	594.70	594.70	0
CENSARA	**NE**	North Omaha Station	**2291**	4	718.39	718.39	0
CENSARA	**NE**	North Omaha Station	**2291**	5	1,359.35	1,359.35	0
CENSARA	**NE**	Platte	**59**	1	676.03	676.03	0
CENSARA	**NE**	Sheldon	**2277**	1	2,282.38	2,282.38	0
CENSARA	**NE**	Sheldon	**2277**	2	1,580.65	1,580.65	0
CENSARA	**OK**	AES Shady Point	**10671**	1A	246.32	246.32	0
CENSARA	**OK**	AES Shady Point	**10671**	1B	203.90	203.90	0
CENSARA	**OK**	AES Shady Point	**10671**	2A	222.77	222.77	0
CENSARA	**OK**	AES Shady Point	**10671**	2B	228.02	228.02	0
CENSARA	**OK**	Grand River Dam Authority	**165**	1	0.00	0.00	0
CENSARA	**OK**	Grand River Dam Authority	**165**	2	1,938.26	1,938.26	0
CENSARA	**OK**	Hugo	**6772**	1	1,464.79	1,464.79	0
CENSARA	**OK**	Muskogee	**2952**	6	2,731.91	2,731.91	0
CENSARA	**OK**	Northeastern	**2963**	3313	0.00	0.00	0
CENSARA	**OK**	Northeastern	**2963**	3314	0.00	0.00	0
CENSARA	**OK**	Sooner	**6095**	1	1,249.20	1,249.20	0
CENSARA	**OK**	Sooner	**6095**	2	1,328.20	1,328.20	0
CENSARA	**TX**	AES Deepwater, Inc.	**10670**	01001	0.00	0.00	0
CENSARA	**TX**	Big Brown	**3497**	1	1,130.75	1,092.26	-38.48
CENSARA	**TX**	Big Brown	**3497**	2	1,364.12	1,328.36	-35.76
CENSARA	**TX**	Coleto Creek	**6178**	1	974.29	974.29	0
CENSARA	**TX**	Gibbons Creek Steam Electric Station	**6136**	1	869.62	869.62	0
CENSARA	**TX**	H W Pirkey Power Plant	**7902**	1	2,310.08	2,310.08	0
CENSARA	**TX**	Harrington Station	**6193**	061B	815.91	815.91	0
CENSARA	**TX**	Harrington Station	**6193**	062B	794.94	794.94	0
CENSARA	**TX**	Harrington Station	**6193**	063B	780.59	780.59	0
CENSARA	**TX**	J K Spruce	**7097**	**1	1,218.22	1,218.22	0
CENSARA	**TX**	J K Spruce	**7097**	**2	563.83	563.83	0
CENSARA	**TX**	J T Deely	**6181**	1	0.00	0.00	0
CENSARA	**TX**	J T Deely	**6181**	2	0.00	0.00	0
CENSARA	**TX**	Limestone	**298**	LIM1	2,964.96	2,964.96	0
CENSARA	**TX**	Limestone	**298**	LIM2	3,358.46	3,358.46	0
CENSARA	**TX**	Martin Lake	**6146**	1	2,482.70	2,482.70	0
CENSARA	**TX**	Martin Lake	**6146**	2	2,289.96	2,289.96	0
CENSARA	**TX**	Martin Lake	**6146**	3	2,227.89	2,227.89	0
CENSARA	**TX**	Monticello	**6147**	1	1,220.42	1,220.42	0
CENSARA	**TX**	Monticello	**6147**	2	894.12	872.34	-21.78
CENSARA	**TX**	Monticello	**6147**	3	1,941.96	1,728.21	-213.75
CENSARA	**TX**	Oak Grove 1	**6180**	1	1,039.17	1,039.17	0

Impact of Wintertime SCR/SNRC Optimization on Visibility Impairing Nitrate Precursor Emissions

RPO	St.	Facility Name	Orispl	Unit ID	Base	BOR	Difference
CENSARA	**TX**	Oak Grove 2	**6180**	2	810.30	810.30	0
CENSARA	**TX**	Oklaunion Power Station	**127**	1	2,447.23	2,447.23	0
CENSARA	**TX**	Sam Seymour	**6179**	1	1,102.92	1,102.92	0
CENSARA	**TX**	Sam Seymour	**6179**	2	1,108.58	1,108.58	0
CENSARA	**TX**	Sam Seymour	**6179**	3	763.06	763.06	0
CENSARA	**TX**	San Miguel	**6183**	SM-1	1,393.96	1,393.96	0
CENSARA	**TX**	Sandow	**6648**	4	584.65	584.65	0
CENSARA	**TX**	Sandow 5	**52071**	5A	309.52	309.52	0
CENSARA	**TX**	Sandow 5	**52071**	5B	235.03	235.03	0
CENSARA	**TX**	Sandy Creek	**56611**	S01	440.75	440.75	0
CENSARA	**TX**	Tolk Station	**6194**	171B	2,307.83	2,307.83	0
CENSARA	**TX**	Tolk Station	**6194**	172B	1,333.66	1,333.66	0
CENSARA	**TX**	Twin Oaks Power, LP	**7030**	U1	428.13	428.13	0
CENSARA	**TX**	Twin Oaks Power, LP	**7030**	U2	600.46	600.46	0
CENSARA	**TX**	W A Parish	**3470**	WAP5	455.85	455.85	0
CENSARA	**TX**	W A Parish	**3470**	WAP6	626.05	626.05	0
CENSARA	**TX**	W A Parish	**3470**	WAP7	344.63	344.63	0
CENSARA	**TX**	W A Parish	**3470**	WAP8	457.92	457.92	0
CENSARA	**TX**	Welsh Power Plant	**6139**	1	2,397.10	2,397.10	0
CENSARA	**TX**	Welsh Power Plant	**6139**	2	0.00	0.00	0
CENSARA	**TX**	Welsh Power Plant	**6139**	3	2,132.07	2,132.07	0

APPENDIX R

High Electric Demand Days and Visibility Impairment in MANE-VU

MANE-VU Technical Support Committee
12/20/2017

MANE - VU
Mid-Atlantic/Northeast Visibility Union

Acknowledgements

The paper has been the effort of MANE-VU Technical Support Committee's Four-Factor Workgroup. Rob Sliwinski of New York Department of Environmental Conservation chaired the Technical Support Committee, whom were responsible for review of the report. Claire Sickinger, Kate Knight, and Kurt Kebschull from Connecticut Department of Energy and Environmental Protection; Mark Wert and Azin Kavian from Massachusetts Department of Environmental Protection; Mary Jane Rutkowski from Maryland Department of the Environment; Tom Downs, Tom Graham and Martha Webster from Maine Department of Environmental Protection; David Healy from New Hampshire Department of Environmental Services; Ray Papalski, Stella Oluwaseun-Apo, and Victoria Faranca from New Jersey Department of Environmental Protection; Scott Griffin and Amanda Chudow from New York Department of Environmental Conservation; Bryan Oshinski from Pennsylvania Department of Environmental Protection and Bennet Leon and Dan Riley of Vermont Department of Environmental Conservation provided valuable insights as the project progressed. Maine staff was particularly instrumental in the visibility data back trajectory analyses, and Claire Sickinger, Stella Oluwaseun-Apo, and Amanda Chudnow each conducted independent analysis of ISO-NE, PJM, and ISO-NY respectively that made up the bulk of the energy demand analysis. Joseph Jakuta managed the workgroup as MANE-VU staff.

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Introduction

The Federal Clean Air Act and Regional Haze rule require States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment within the national parks and wilderness areas designated as mandatory Class I Federal Areas. To address the impact on Class I Federal areas within the Mid-Atlantic /Northeast Visibility Union (MANE-VU) region, the MANE-VU States will pursue a coordinated course of action to assure reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal areas. This course of action includes pursuing the adoption and implementation of emission management strategies.

One of the emission management strategies that will be considered for adoption and implementation by the MANE-VU Class I States is for the MANE-VU States to perform a four-factor analysis for peaking combustion turbines that operate on high electric demand days to address and control oxides of Nitrogen (NOx) and sulfur dioxide (SO2) emissions, where:

a) "High Electric Demand Day or "HEDD" is defined as the day when higher than usual electrical demands bring additional generation units online, many of which are infrequently operated and may have significantly higher emission rates than the rest of the generation fleet and,

b) "Peaking combustion turbine" is defined for the purposes of the MANE-VU "Ask" as a turbine capable of generating 15 megawatts or more, that commenced operation prior to May 1, 2007, used to generate electricity all or part of which is delivered to the electric power distribution grid for commercial sale, and that operates less than or equal to an average of 1752 hours (or 20%) per year during 2014 to 2016.

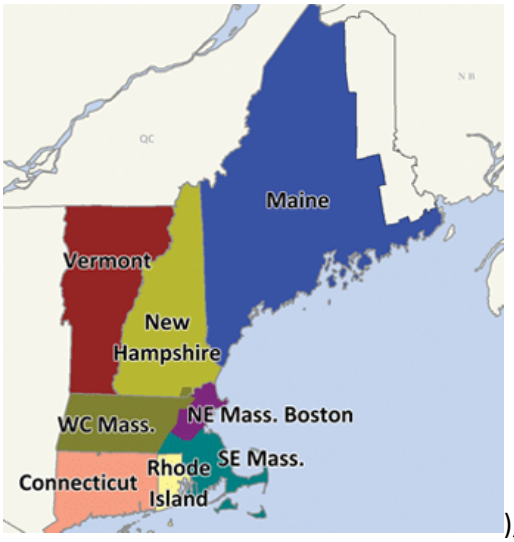
This analysis reviews visibility and energy data to determine the impact electric load has on visibility impairment, specifically the impacts of HEDDs on the "20% most impaired visibility days,"[1] though it also looks at the older 20% worst day metric as well.

Scope and Domain

As discussed in the above, the purpose of this study is to review the impact of ISO-NE, ISO-NY, and PJM HEDD on the MANE-VU region's visibility. Therefore, the analysis encompasses two domains: that of ISO-NE, ISO-NY, and PJM for the HEDD analysis and that of MANE-VU (plus some neighboring areas) for the visibility impairment analysis.

Specifically, the following figures depict the region analyzed for HEDD; the Independent System Operator (ISO) for the energy distribution in New England (Figure 1

[1] 20% most impaired days are based on the draft IMPROVE AEROSOL, RHR III methodology used to calculate visibility impairment available in the Federal Land Manager Environmental Database (FED) database as of June 8, 2017 in accordance with the new definitions of impairment in regional haze regulatory framework



), the ISO for energy distribution in New York (Figure 2) and the Regional Transmission Organization (RTO) for the Mid-Atlantic, PJM (Figure 3). ISO-NE is responsible for administering the power plants, maintaining the electric grid, and operating the power market for the region.

Figure 1: ISO-NE region and load zones within the region

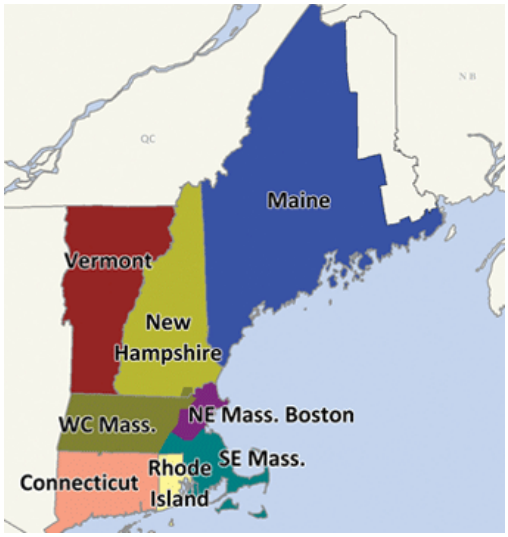


Figure 2: ISO-NY region and load zones within the region

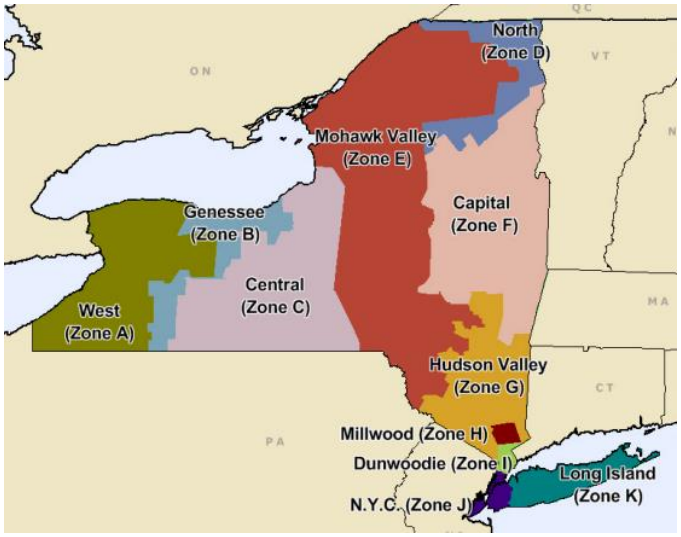
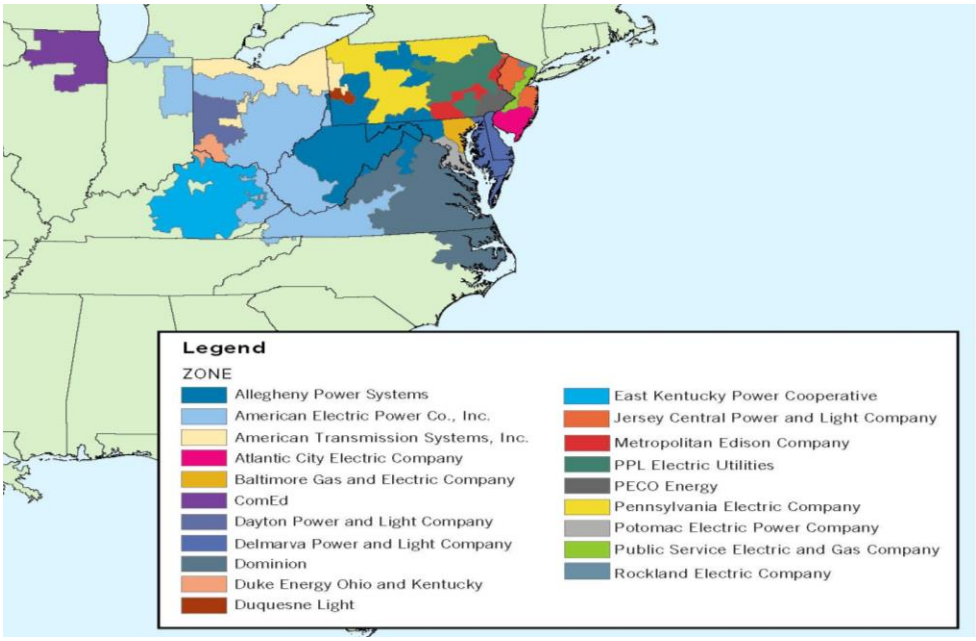


Figure 3: PJM region and load zones within the region



The region examined for the visibility impairment includes all of the MANE-VU. The states included in MANE-VU are Maine, New Hampshire, Vermont, Rhode Island, Massachusetts, Connecticut, New York, New Jersey, Delaware, Maryland, Pennsylvania, and the District of Columbia. Nearby states that are not in MANE-VU but frequently impact visibility in MANE-VU are also included in portions of the analysis, the extent of which was determined by the extent the air mass traveled in a 72-hour period. Within the MANE-VU region, the federally designated Class I areas are Brigantine Wilderness Area in the Edwin B. Forsythe National Wildlife Refuge (Brigantine), New Jersey; Lye Brook Wilderness (Lye Brook), Vermont; Great Gulf Wilderness and Presidential Range - Dry River Wilderness (Great Gulf), New Hampshire;

Acadia National Park (Acadia), and Moosehorn Wilderness (Moosehorn), Maine; and Roosevelt Campobello International Park, Maine/New Brunswick, Canada.

The scope of the analysis was originally intended to only review the most recent set of data that both IMPROVE (Interagency Monitoring of Protected Visual Environments) monitoring and HEDD data have available, 2015.

HEDD Analysis

HEDD are defined as the 85th percentile of the daily peak demand.[2] The 85th percentile was chosen to evaluate HEDD in part to be consistent with the analyses of the surrounding ISOs/RTOs and in part because it approximates the value which was determined to be an appropriate definition of HEDD for the New Jersey HEDD rule.[3] This section evaluated the daily peak demand data for 2015 to define the HEDDs to compare against visibility impairment in the following sections.

Electric Load Data

Electric load data was obtained from the ISO-NE, ISO-NY, and PJM Interconnection. ISO-NE covers the six New England states and ISO-NY solely covers New York. PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

As shown in Table 1, the two 85th percentile values for all three ISOs/RTOs are very close showing that we can rely on the 85th percentile on days monitored by IMPROVE.

Table 2 expands on this information by looking at the average peak generation on 20% most impaired days and HEDDs. There is a noticeable difference in the average maximum daily load between 20% most impaired days using all three ranking systems and the other days monitored by IMPROVE. The difference is even more noticeable between HEDDs and non HEDDs.

Table 1: Maximum, 85th Percentile, and 85th Percentile maximum daily generation (MWh) on IMPROVE monitored days

	ISO-NE	ISO-NY	PJM
Maximum	24,074	18,168	143,633
85th Percentile	19,331	11,432	122,756
85th Percentile on IMPROVE Days	19,261	11,515	122,252

Table 2: Average Generation (MWh) in each ISOs/RTOs on most impaired days and other monitored days ranked using three methods and on HEDDs and non-HEDDS on monitored days at each Class I Area.

	Old Ranking		Anthropogenic Ranking		Impairment Ranking		HEDD on Monitored Day		All Monitored
	Top 20%	Other Days	Top 20%	Other Days	Top 20%	Other Days	Y	N	Days
Acadia	48,866	41,975	47,617	42,284	47,617	42,284	55,363	41,102	**43,341**
ISO-NE	19,222	16,430	18,600	16,583	18,600	16,583	21,171	16,203	**16,983**
ISO-NY	10,915	8,368	9,918	8,615	9,918	8,615	13,617	7,990	**8,874**
PJM	116,461	101,126	114,332	101,653	114,332	101,653	131,301	99,113	**104,168**
Brigantine	48,448	42,078	47,601	42,288	47,601	42,288	55,363	41,102	**43,341**
ISO-NE	18,918	16,505	18,382	16,637	18,382	16,637	21,171	16,203	**16,983**

[2] Data provided by ISO-NE, https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info
[3] N.J.A.C. 7:27-19

	Old Ranking		Anthropogenic Ranking		Impairment Ranking		HEDD on Monitored Day		All Monitored
	Top 20%	Other Days	Top 20%	Other Days	Top 20%	Other Days	Y	N	Days
ISO-NY	10,845	8,386	10,181	8,550	10,181	8,550	13,617	7,990	**8,874**
PJM	115,582	101,343	114,240	101,675	114,240	101,675	131,301	99,113	**104,168**
Great Gulf	50,842	41,371	47,410	42,146	47,410	42,146	57,504	40,418	**43,116**
ISO-NE	19,397	16,313	18,663	16,479	18,663	16,479	21,373	16,094	**16,881**
ISO-NY	11,787	8,194	10,026	8,592	10,026	8,592	13,732	7,942	**8,856**
PJM	121,342	99,605	113,541	101,367	113,541	101,367	131,301	98,071	**103,609**
Lye Brook	48,467	42,025	n/a	n/a	n/a	n/a	57,652	40,734	**43,279**
ISO-NE	18,796	16,470	n/a	n/a	n/a	n/a	21,089	16,185	**16,923**
ISO-NY	11,258	8,225	n/a	n/a	n/a	n/a	13,779	7,996	**8,815**
PJM	115,345	101,379	n/a	n/a	n/a	n/a	131,181	98,967	**104,098**
Moosehorn	48,936	42,367	48,271	42,533	48,271	42,533	55,363	41,242	**43,681**
ISO-NE	19,156	16,596	18,925	16,653	18,925	16,653	21,171	16,259	**17,108**
ISO-NY	10,816	8,575	10,233	8,721	10,233	8,721	13,617	8,064	**9,023**
PJM	116,835	101,930	115,656	102,225	115,656	102,225	131,301	99,401	**104,911**
Grand Total	**49,080**	**41,960**	**47,723**	**42,534**	**47,723**	**42,534**	**56,205**	**40,921**	**43,349**

Figure 4 shows the electric demand (dots) for 2015 for each ISOs/RTOs with blue being ISO-NE, orange being ISO-NY, and green being PJM. The lighter lines represent the 85th percentile of daily demand for the year, while the darker lines represent the 85th percentile of electric demand on IMPROVE days. There is a clear spike in electric demand during the summer months in all ISOs/RTOs, with a lesser spike during the winter months, with some of the lower demand values occurring in spring and fall.

Figure 4: Peak daily demand (GWh) in ISO-NE (blues, right scale), ISO-NY (oranges, right scale), and PJM (greens, left scale) 2015

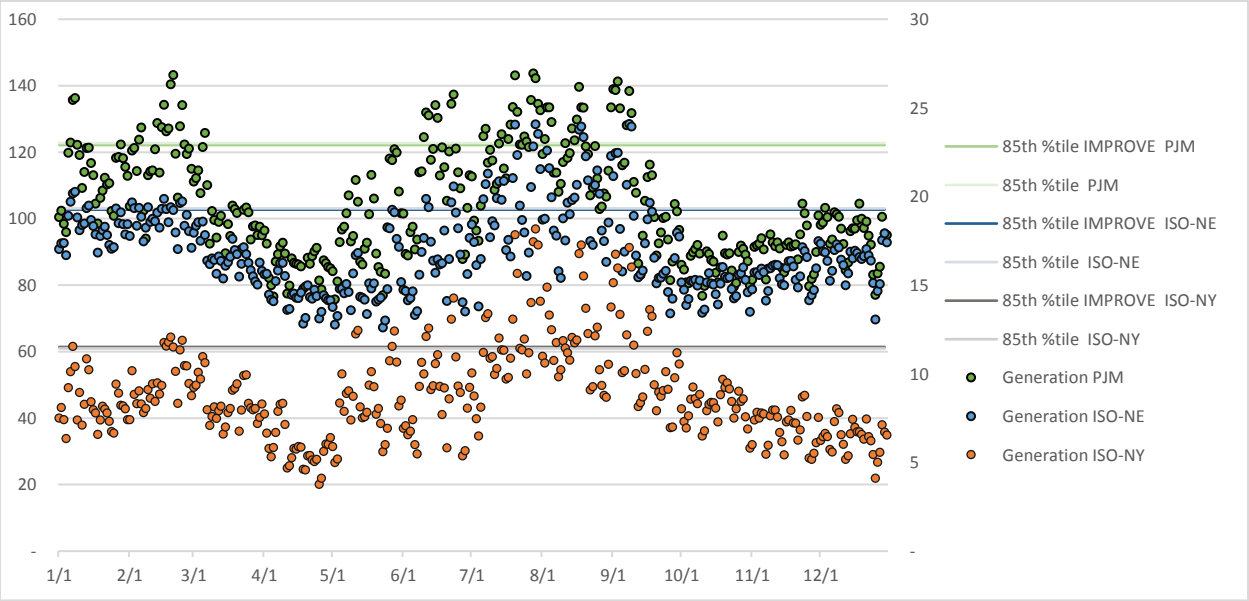


Figure 5, shows which IMPROVE monitored days occurred during 85th percentile days, 85th percentile IMPROVE monitored days, or both. In all of three ISOs/RTOs the HEDDs begin occurring in mid to late-May and extend throughout the summer ending in early to mid-September. In all three ISOs/RTOs there are also HEDDs that occur during January and February.

Figure 5: Peak daily demand (GWh) on IMPROVE sample days, 2015

Visibility Data Analysis

The following portion of the analysis reviews the visibility impairment at the MANE-VU and nearby Class I areas and evaluates any/if any correlation in the occurrence in impairment and HEDD. The full visibility analysis was prepared by Maine DEP for MANE-VU and will be released as a separate report.[4]

Best Visibility Days Analysis

A comparison of the visibility values against the HEDD were also evaluated. If the correlation was similar to the worst days, it might indicate that HEDD sources are not significant in the issue of visibility impairment. However, this analysis revealed that the occurrence of a HEDD day on the days deemed "best visibility" was in fact significantly rarer than the occurrence with impaired days as seen in Table 3. Great Gulf did not have a best day occur on the same day as a HEDD in any ISO/RTO. Acadia and Moosehorn had one best day occur on the same day as a HEDD in ISO-NE. Brigantine and Lye Brook both only had one best day occur during a HEDD in ISO-NY. Acadia and Moosehorn also had two best days occur during HEDDs in ISO-NY and PJM, respectively. It would be expected that HEDDs would not occur on best visibility days and that expectation appears correct.

Table 3: Number of HEDDs on Best Days

Site	Monitored Days	ISO-NE	ISO-NY	PJM
ACAD1	23	1	2	0
BRIG1	23	0	1	0
GRGU1	21	0	0	0
LYEB1	21	0	1	0
MOOS1	21	1	1	2

20% Most Impaired Visibility Day Analysis

The data shown in both Table 4 and Figure 6 demonstrate that poor visibility days often occur on HEDDs. Table 4 shows the counts of the number of 20% most impaired days using three different ranking techniques and find that between 57% and 29% of all HEDDs occur on the most impaired days depending on the ranking methodology and which ISO/RTO is being looked at. Since the impairment method can remove days from consideration that experience both high impact from fires and anthropogenic emissions that would go to explain that decrease in number of HEDDs seen on most impaired days.

Table 4: Number of HEDDs on 20% Most Impaired using three ranking techniques

		Old Rank			Anthropogenic			Impairment		
Site	**Monitored Days**	**ISO-NE**	**ISO-NY**	**PJM**	**ISO-NE**	**ISO-NY**	**PJM**	**ISO-NE**	**ISO-NY**	**PJM**
ACAD1	24	12	11	11	11	10	10	8	8	10
BRIG1	24	9	10	7	9	9	7	8	7	7
GRGU1	21	11	11	12	9	9	11	7	7	8
LYEB1	22	9	10	7	n/a	n/a	n/a	n/a	n/a	n/a
MOOS1	22	10	9	9	11	10	10	9	9	9

The middle quintile rankings were not available in data sets for the anthropogenic and impairment methods so we also looked strictly at the old "worst day" ranking to see when HEDDs occurred on other

[4] 2017, Regional Haze Visibility Update, Tom Downs, Martha Webster and Rich Greves, Maine DEP

impairment days. Figure 6 shows that the 20% worst days clearly line up with HEDDs and decrease as visibility improves.

Figure 6: Total HEDDs in each ISO/RTO during each quintile of day using the old "worst day" method

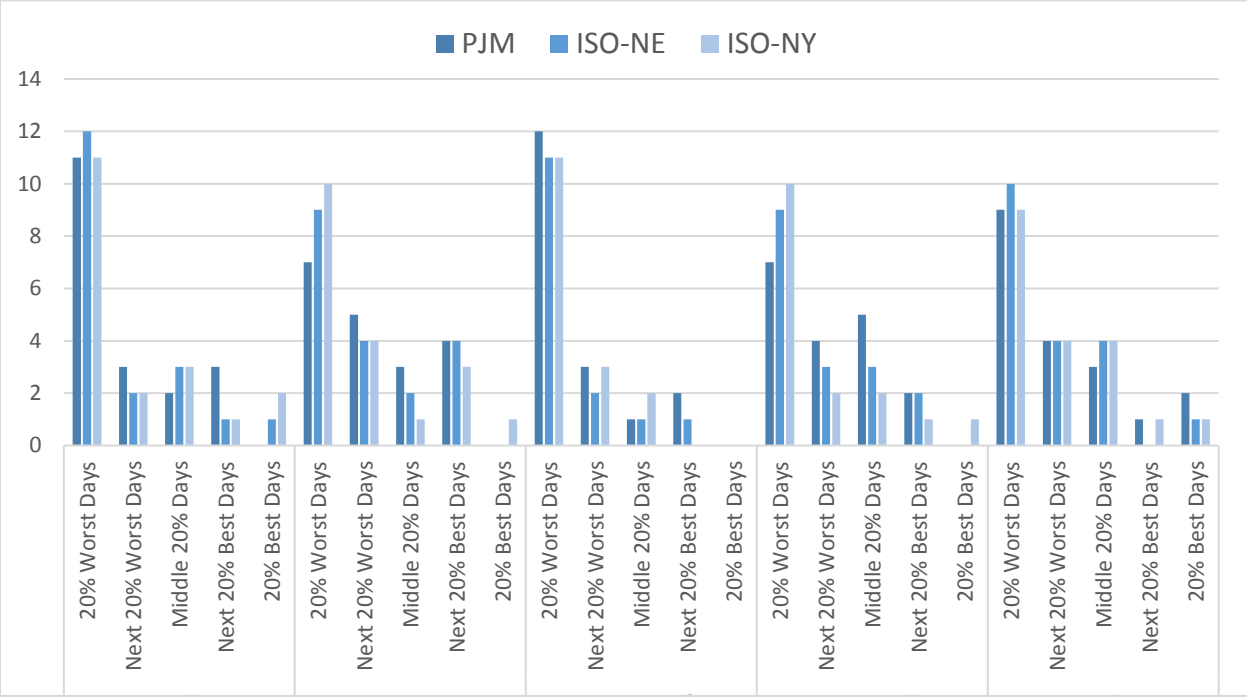


Figure 7 shows the speciation analyses for the 20% most impaired visibility days and Figure 8 shows the speciation analyses for the 20% most impaired visibility days at each MANE-VU Class I Area in 2015. We only looked at speciation on the 20% worst days and the 20% most impaired days using the impairment method, since all 20% most impaired days calculated using the anthropogenic method were included in one of the other sets of days. Lye Brook was not included since 20% most impaired data was not available for 2015.

The HEDD that occur on the most impaired days for each Class I Area are distinguished by the label with their percentile ranking. Ammonium sulfate has the highest extinction year-round at all Class I Areas except Brigantine, which showed multiple instances of ammonium nitrate extinction exceeding that of ammonium sulfate, however only one of those corresponded to a HEDD. At all Class I Areas, ammonium nitrate extinction was highest in the cooler months and lowest in the warmer months. Organic mass extinction was significant in all Class I Areas and elemental carbon only stood out as a significant contributor on a few days at Brigantine. Sea salt extinction was noticeable at Acadia and Brigantine, and on one day at Moosehorn, which was also a HEDD, however sea salt not a pollutant that would indicate energy sources were the cause. More than half of the 20% most impaired days occurred in the winter and summer for all areas in 2015.

Figure 7: Speciation (left axis) of the 20% most impaired days and the maximum daily load (GWh) (right axis) in ISO-NE, ISO-NY, and PJM with HEDDs noted in orange at each Class I Area.

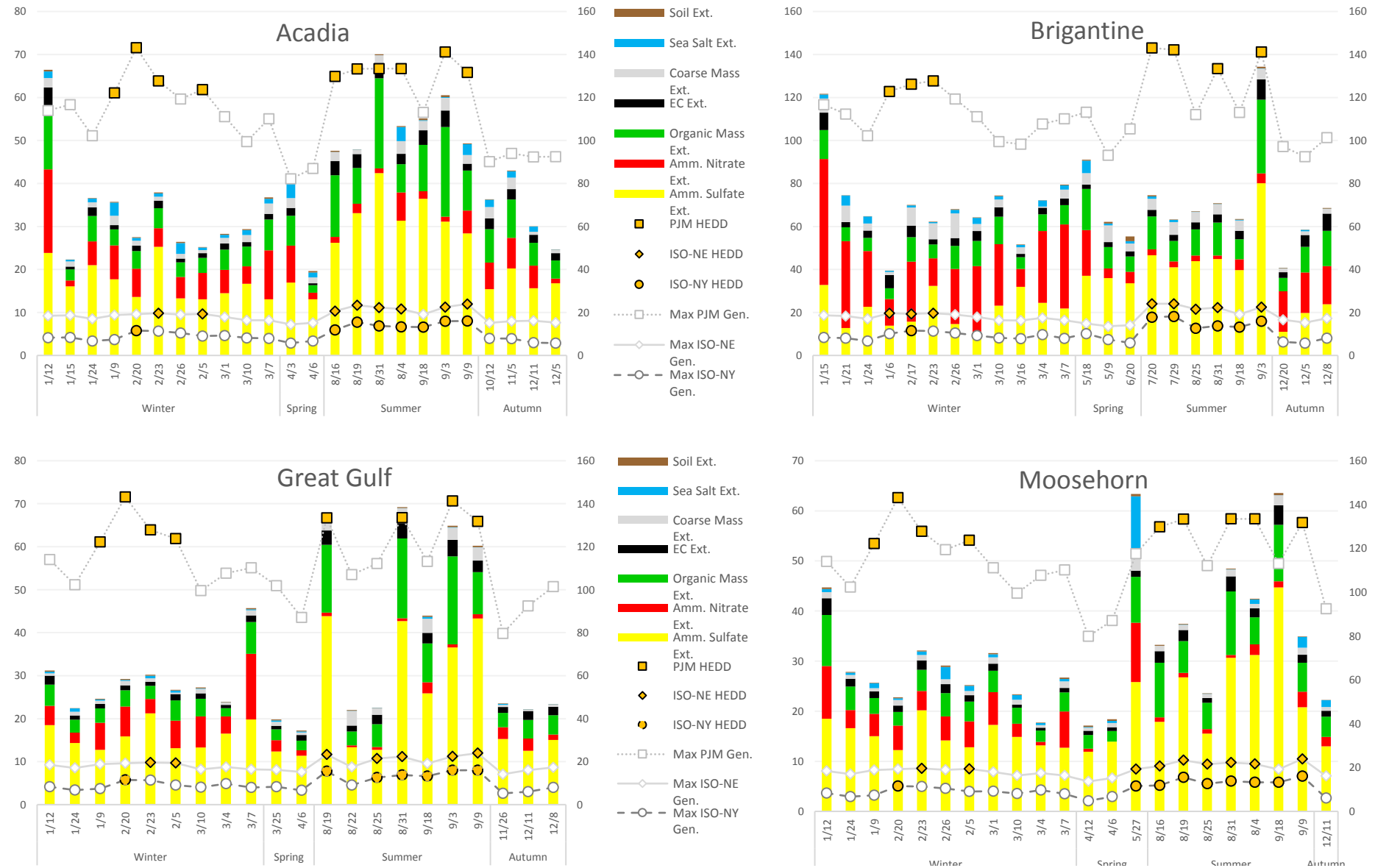
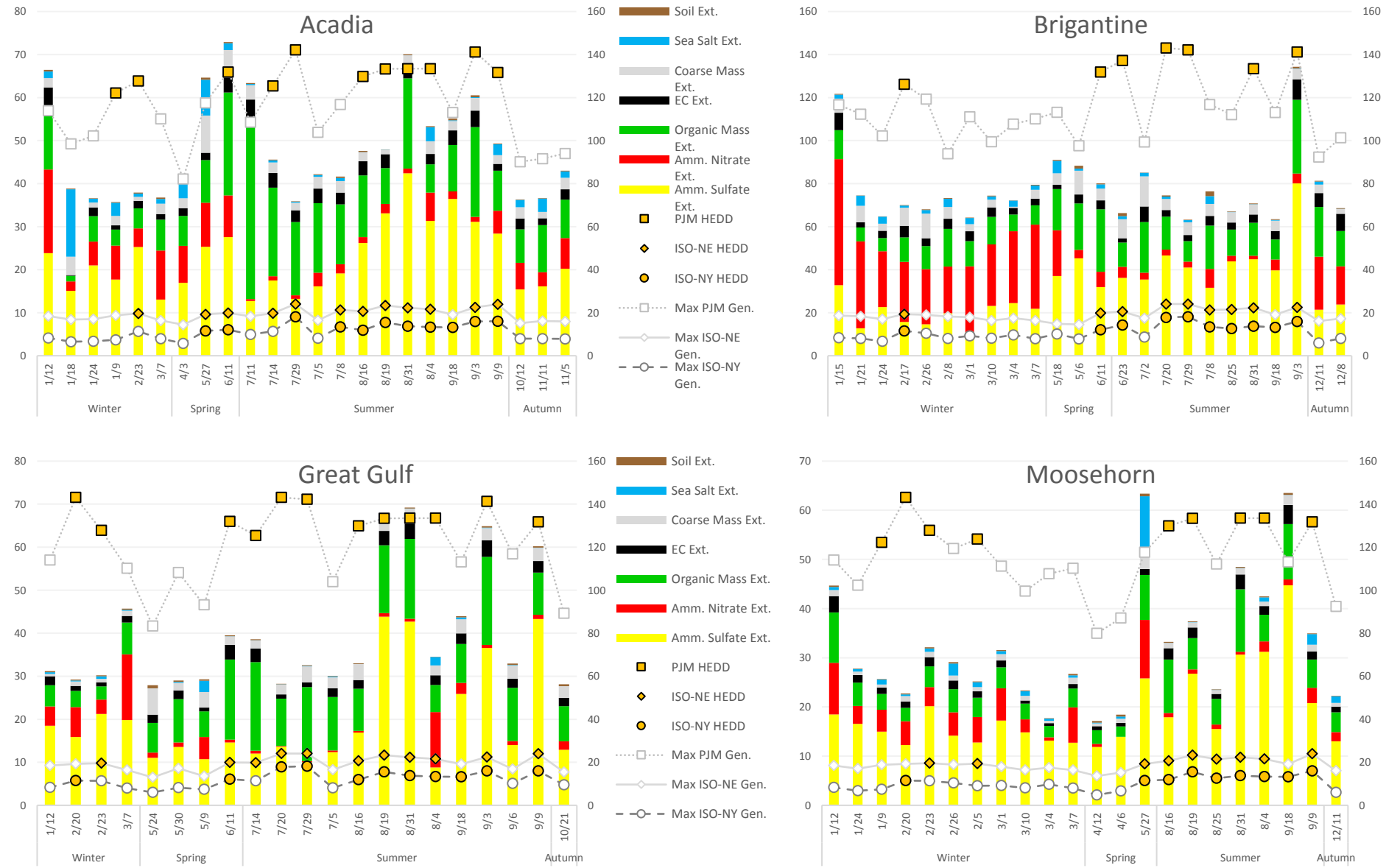


Figure 8: Speciation (left axis) of the 20% worst days and the maximum daily load (GWh) (right axis) in ISO-NE, ISO-NY, and PJM with HEDDs noted in orange at each Class I Area.

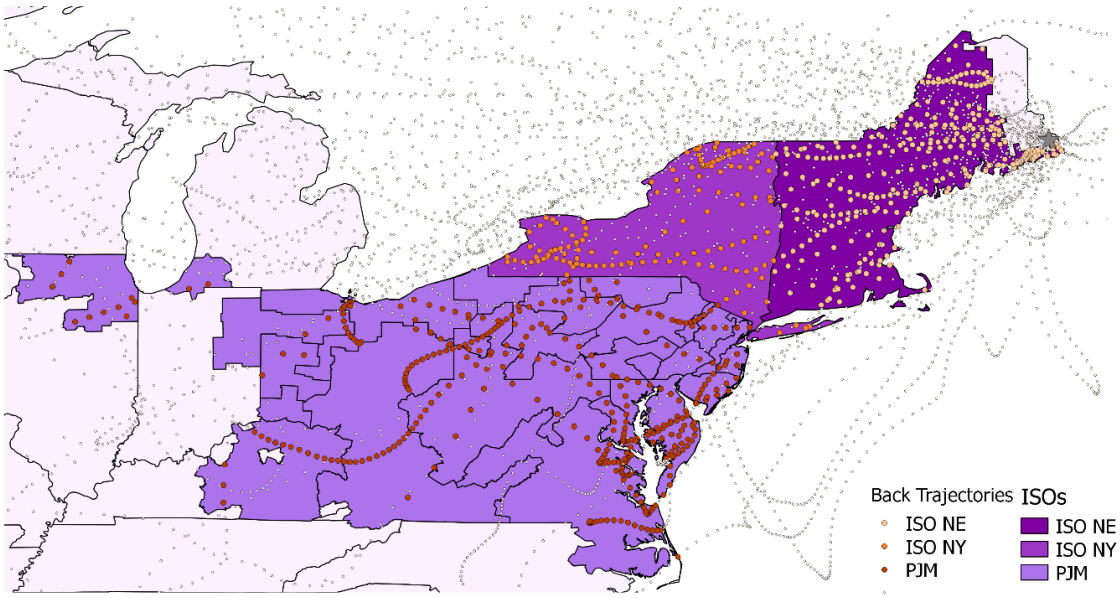


HYSPLIT Analysis of Most Impaired Visibility Days

The HYSPLIT model was used to develop 72-hour back trajectories at 500m four times per day (3 AM, 9 AM, 3 PM, and 9 PM) to determine the wind patterns on the most impaired days. These back trajectories were developed for a previous report by Maine DEP.[5] Back trajectories were not developed for the 20% worst days for this report so only the 20% most impaired days as ranked using the impairment method were used. The trajectories were overlaid on a map of the area covered by each of the ISOs/RTOs to graphically display how the wind patterns matched with the foot print of the ISOs/RTOs. The back trajectories that went over the geography of the ISO/RTO during the days that were a HEDD were highlighted.

Figure 9 shows the back trajectories during 20% most impaired days for Acadia, Great Gulf, and Moosehorn, respectively, which occurred during a HEDD in at least one ISO/RTO. The patterns in each map are similar with the most back trajectories in ISO-NE, and several crossing ISO-NY and PJM. It would be reasonable to expect that all three ISOs/RTOs analyzed could play a role in impacting visibility conditions in each of those Class I areas.

Figure 9: 72-hour back trajectories at 3 AM & PM and 9 AM & PM from Moosehorn during 20% most impaired days that were HEDDs in one analyzed ISO/RTO at 500m



[5] Mid-Atlantic Northeast Visibility Union, *Regional Haze Metrics Trends and HYSPLIT Trajectory Analyses*.

Figure 10: 72-hour back trajectories at 3 AM & PM and 9 AM & PM from Acadia during 20% most impaired days that were HEDDs in one analyzed ISO at 500m

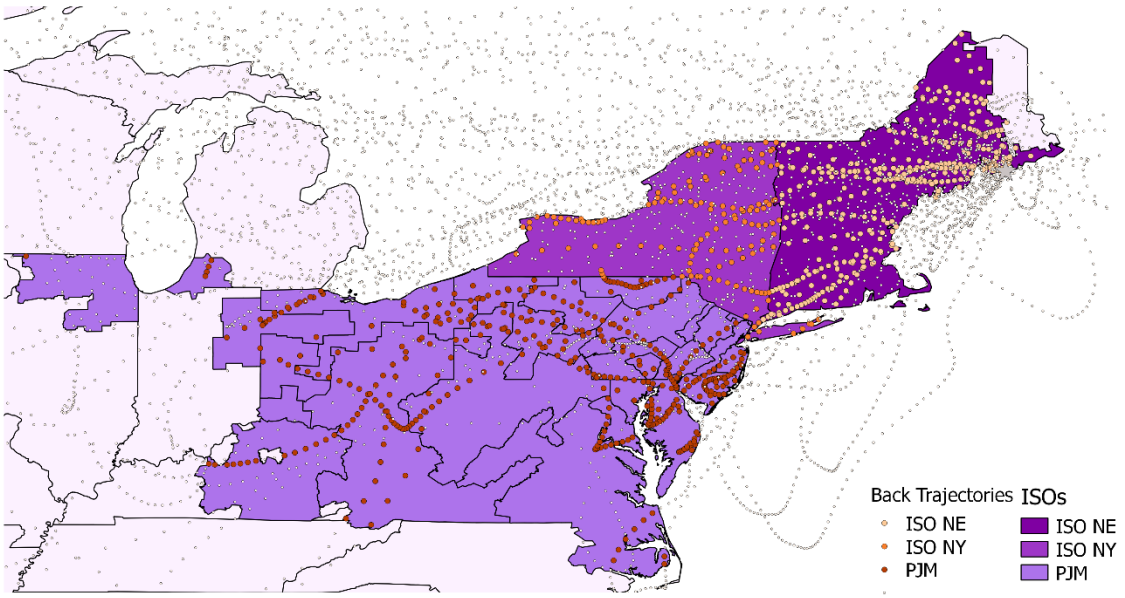


Figure 11: 72-hour back trajectories at 3 AM & PM and 9 AM & PM from Great Gulf during 20% most impaired days that were HEDDs in one analyzed ISO/RTO at 500m

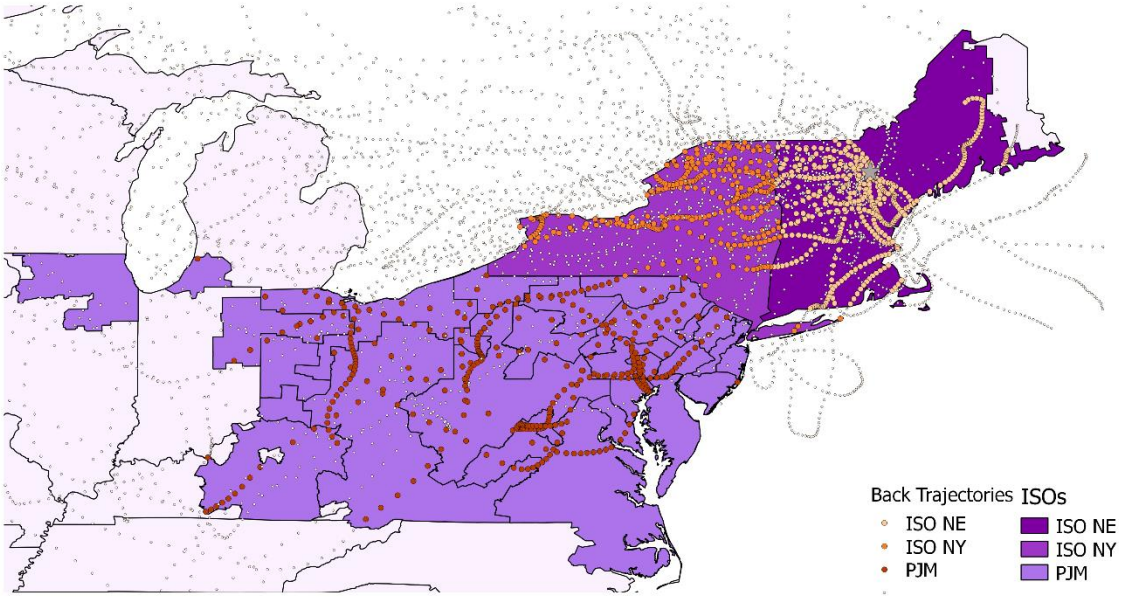


Figure 12 shows the back trajectories during 20% most impaired days for Lye Brook that occurred during a HEDD in at least one ISO/RTO. The pattern for Lye Brook is similar to that of the other New England Class I Areas, except due to it being on the western side of ISO-NE, the impact of ISO-NY would appear to be greater and that of ISO-NE to be minimal.

Figure 12: 72-hour back trajectories at 3 AM & PM and 9 AM & PM from Lye Brook during 20% most impaired days that were HEDDs in one analyzed ISO/RTO at 500m

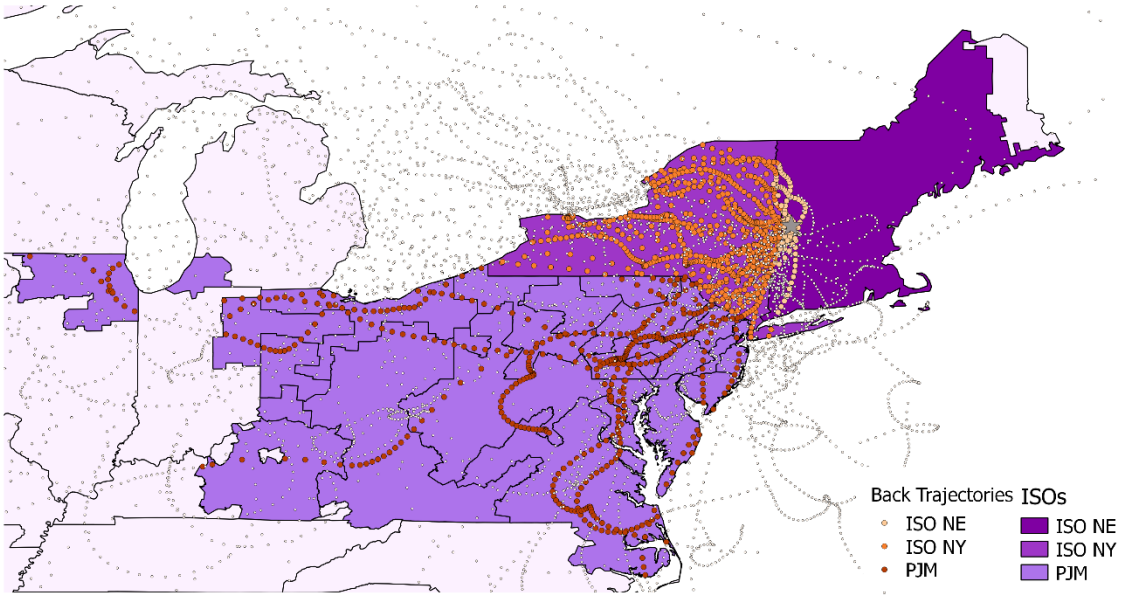
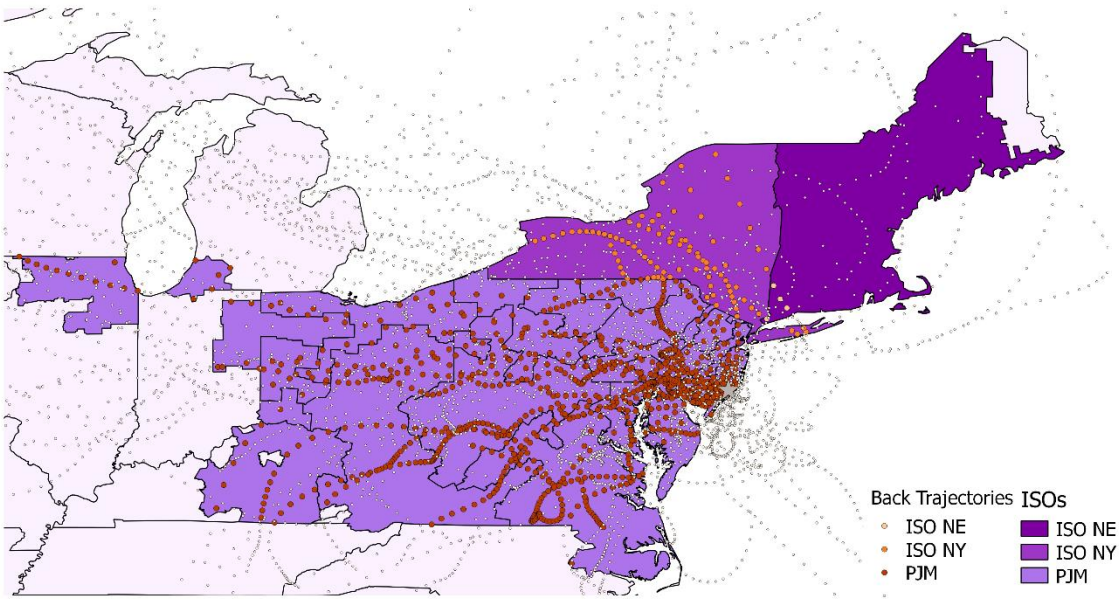


Figure 13 shows the back trajectories during 20% most impaired days for Brigantine that occurred during a HEDD in at least one ISO/RTO. It is clear from the trajectories that, in 2015, ISO-NE has little influence on poor visibility at Brigantine, but emissions from PJM are an important indicator of poor visibility during HEDDs. ISO-NY could potentially have an impact on visibility issues in Brigantine as well, especially from the western part of the ISO/RTO.

Figure 13: 72-hour back trajectories at 3 AM & PM and 9 AM & PM from Brigantine during 20% most impaired days that were HEDDs in one analyzed ISO/RTO at 500m



Meteorological Factors

Brigantine

Preliminary meteorological analysis shows that on HEDD and on the most impaired days, a common meteorological feature, called a low pressure surface trough or the Appalachian Lee-side Trough (APLT), exists that creates favorable conditions for poor visibility at Brigantine. This feature allows polluted air aloft to easily mix down to the surface and combine with local emissions. This feature is frequently seen west of New Jersey on days prior to as well as on the most impaired days. In addition, on days when extreme temperatures cause electricity generating units to operate at a higher capacity due to increased demand, increased pollutant levels is released into the atmosphere. As a result, downwind locations may see an increase in haze or pollutant concentrations on the next day.

Calm winds at the coast are also commonly seen on days of visibility impairment at Brigantine. Calm winds create poor atmospheric ventilation for pollutants to disperse in the atmosphere. Brigantine's unique location near the coast makes it an ideal downwind endpoint for pollutants to accumulate that travel from the west. If any units operate without controls on days prior to the most impaired days, a greater amount of pollution from upwind States travels eastward to Brigantine. Persistence can also be a factor, i.e., when there are several days of stagnation during prolonged hot or cold periods. Extended periods of extreme temperatures with little atmospheric ventilation can cause electric generating units to operate at higher levels of demand for several days in a row, during which pollutants accumulate in

the same location when there is poor atmospheric ventilation. As a result, when finally the heavily polluted air mass is pushed downwind, it creates poor visibility in the downwind areas.

New England Class I Areas

Poor visibility can be associated with several weather patterns during winter and summer months at the New England Class I Areas. During the summer, high pressure moving from the Midwest to off the coast of the Mid-Atlantic States setting up a Bermuda High with west to southwest transport winds leads to impairment in New England's Class I areas. Another pattern that leads to the transport of visibility impairing pollution to New England Class I areas is the Lee-side Trough, which sets up resulting in Southwest flow of pollutants from large cities in the Northeast to New England's Class I areas. The Lee-side Trough also help turn the winds in the Gulf of Maine resulting in transported pollution to Maine's Class I areas by sea breezes. Finally, southerly winds can transport pollution from large cities in the Northeast to the New Hampshire and Vermont Class I areas.

Meteorological conditions that lead to visibility impairment in the winter differ from those in the summer at New England Class I areas. In some instances very cold air masses sit in place resulting in a HEDD with higher power plant emissions and higher residential heating emissions. Winds tend to be more from the Northwest in these events with emissions from Canada also contributing to the pollution at New England Class I areas. In other situations, a high pressure system moving into the Northeast from the Midwest and large cities in the Northeast will set up a subsidence inversion pushing aloft transported pollution closer to the surface. This type of event is much warmer than the HEDD events and are more polluted with a stalled or slow moving High Pressure system and can happen in any season of the year. Finally, nighttime inversions will trap pollutants near the surface. Pollution levels are higher during the winter during these inversions because they last longer than in any other season. Inland Class I areas are more impacted by this type of event.

Analysis of Days Preceding the Most Impaired Visibility Days

Electric load data from the three ISOs/RTOs were reviewed for two days preceding the most impaired days for two of the methods (anthropogenic was left off since all 20% most impaired days using that ranking were in the other two sets of days). The two methods showed similar characteristics.

As one can see in Table 5, 20% most impaired days are preceded in the day before and two days before by HEDDs only slightly less often than when they occur on the same day as HEDDs in the different ISOs. In the case of the worst ranking between 50% and 23% of most impaired days are preceded by a HEDD in a particular ISO/RTO and 43% and 17% of most impaired days are preceded by a HEDD two days before in a particular ISO/RTO. Brigantine shows the greatest drop off, likely because it is closer to the ISO/RTO than the other Class I areas so the air masses impacting it two days later are further west than the ISOs/RTOs being analyzed.

Table 5: Number of HEDDs on the day of, day before, and 2 days before 20% most impaired using two ranking techniques

		Old Rank			Impairment		
Site	**When was HEDD?**	**ISO-NE**	**ISO-NY**	**PJM**	**ISO-NE**	**ISO-NY**	**PJM**
Acadia	Day Of	12	11	11	8	8	10
	Day Before	10	9	10	9	7	8
	2 Days Before	8	7	8	8	8	8
Brigantine	Day Of	9	10	7	8	7	7
	Day Before	9	8	8	7	6	5

		Old Rank			Impairment		
Site	**When was HEDD?**	**ISO-NE**	**ISO-NY**	**PJM**	**ISO-NE**	**ISO-NY**	**PJM**
	2 Days Before	5	4	7	4	4	5
Great Gulf	Day Of	11	11	12	7	7	8
	Day Before	10	10	10	8	7	6
	2 Days Before	6	9	9	6	7	5
Lye Brook	Day Of	9	10	7	n/a	n/a	n/a
	Day Before	8	8	11	n/a	n/a	n/a
	2 Days Before	5	8	9	n/a	n/a	n/a
Moosehorn	Day Of	10	9	9	9	9	9
	Day Before	7	7	7	8	7	7
	2 Days Before	6	6	6	6	7	7

When looking at the 20% most impaired days using the impairment ranking a similar pattern holds up as did with HEDDS occurring on most impaired days, that there are slightly fewer. 38% and 21% of most impaired days are preceded by a HEDD in a particular ISO/RTO and 33% and 17% of most impaired days are preceded by a HEDD two days before in a particular ISO/RTO. Again this is likely due to summer days with high impairment from HEDD units, among other sources, being excluded from consideration since they coincided with days with high levels of impairment from fires. This of course doesn't clear up whether HEDDs are occurring directly in the lead up to a HEDD that is occurring during a 20% most impaired visibility day.

Table 6 and Table 7 help to answer the question of whether there are HEDDs occurring in the lead up to a HEDD that is occurring during a 20% most impaired visibility day when looking at the impairment method and the old "worst day" method, respectively. It is often that a HEDD occurring during a 20% most impaired day has HEDDs in the day or two days prior, particularly during the summer. There are also several instances where there is not a HEDD during the 20% most impaired day, but has HEDDs in the day or two days prior, particularly during the winter.

Table 6: Max daily load (MWh) on HEDDs in each ISO that occur the day of, the day before, and two days before a 20% most impaired day at each Class I Area

			ISO-NE			ISO-NY			PJM		
Site	Season	Date	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before
Acadia	Winter	1/9		20,255	20,162			11,534		136,197	135,639
		1/12									
		1/18									
		1/24									
		2/23	19,625						127,775		
		3/7								125,702	
	Spring	4/3									
		5/27				11,535					
		6/11	19,862			12,101			131,922	124,478	
	Summer	7/5									
		7/8	21,291	20,694	19,836	13,382	13,161			126,953	124,745
		7/11									
		7/14	19,806	20,854	19,888		12,009		125,399		
		7/29	24,065	22,810	20,524	18,168	17,443	14,008	142,225	143,633	135,699
		8/4	21,597	22,589		13,299	14,878		133,418	133,436	123,914
		8/16	20,658	19,932	19,783	11,899	11,729	12,047	129,803	123,513	127,063
		8/19	23,345	23,941	23,758	15,512	17,252	16,776	133,354	133,464	139,650
		8/31	22,269			13,764			133,453		
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/9	23,937	24,074	20,657	16,016	17,114	12,190	131,701	138,388	128,068
		9/18		19,636		13,235	13,614	12,384			

			ISO-NE			ISO-NY			PJM		
Site	Season	Date	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before
	Autumn	10/12									
		11/5									
		11/11									
Brigantine	Winter	1/15		19,486	19,332						
		1/21									
		1/24									
		2/8									127,381
		2/17		19,851		11,553	11,759		126,240	134,183	127,475
		2/26			19,723			11,881			134,132
		3/1									
		3/4									
		3/7								125,702	
		3/10									
	Spring	5/6									
		5/18									
		6/11	19,862			12,101			131,922	124,478	
	Summer	6/23	20,563	19,656		14,263	13,076		137,287	134,545	
		7/2									
		7/8	21,291	20,694	19,836	13,382	13,161			126,953	124,745
		7/20	24,055	21,037		17,842	13,081		143,065	133,567	128,265
		7/29	24,065	22,810	20,524	18,168	17,443	14,008	142,225	143,633	135,699
		8/25	21,473	20,643		12,613	12,127				
		8/31	22,269			13,764			133,453		
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/18		19,636		13,235	13,614	12,384			
	Autumn	12/8									
		12/11									
Great Gulf	Winter	1/12									
		2/20		19,382		11,506	12,061	11,781	143,129	140,386	127,107
		2/23	19,625						127,775		
		3/7								125,702	
	Spring	5/9									
		5/24									
		5/30						12,401			
		6/11	19,862			12,101			131,922	124,478	
	Summer	7/5									
		7/14	19,806	20,854	19,888		12,009		125,399		
		7/20	24,055	21,037		17,842	13,081		143,065	133,567	128,265
		7/29	24,065	22,810	20,524	18,168	17,443	14,008	142,225	143,633	135,699
		8/4	21,597	22,589		13,299	14,878		133,418	133,436	123,914
		8/16	20,658	19,932	19,783	11,899	11,729	12,047	129,803	123,513	127,063
		8/19	23,345	23,941	23,758	15,512	17,252	16,776	133,354	133,464	139,650
		8/31	22,269			13,764			133,453		
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/6						13,337			133,169
		9/9	23,937	24,074	20,657	16,016	17,114	12,190	131,701	138,388	128,068
		9/18		19,636		13,235	13,614	12,384			
	Autumn	10/21									
Moosehorn	Winter	2/8									127,381
		2/14								128,761	
		3/4									
		3/7								125,702	
	Spring	4/18									
		5/9									
		5/27				11,535					
		5/30						12,401			
		6/11	19,862			12,101			131,922	124,478	
	Summer	6/23	20,563	19,656		14,263	13,076		137,287	134,545	
		7/5									
		7/8	21,291	20,694	19,836	13,382	13,161			126,953	124,745

			ISO-NE			ISO-NY			PJM		
Site	Season	Date	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before
		7/20	24,055	21,037		17,842	13,081		143,065	133,567	128,265
		7/26						11,947		123,129	124,661
		7/29	24,065	22,810	20,524	18,168	17,443	14,008	142,225	143,633	135,699
		8/19	23,345	23,941	23,758	15,512	17,252	16,776	133,354	133,464	139,650
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/6						13,337			133,169
		9/9	23,937	24,074	20,657	16,016	17,114	12,190	131,701	138,388	128,068
		9/18		19,636		13,235	13,614	12,384			
	Autumn	10/21									
		12/11									

Table 7: Max Daily Load (MWh) on HEDDs in each ISO that occur the day of, the day before, and two days before a 20% worst day at each Class I Are

			ISO-NE			ISO-NY			PJM		
Site	Season	Date	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before
Acadia	Winter	1/9		20,255	20,162			11,534		136,197	135,639
		1/12									
		1/18									
		1/24									
		2/23	19,625						127,775		
		3/7								125,702	
	Spring	4/3									
		5/27				11,535					
		6/11	19,862			12,101			131,922	124,478	
	Summer	7/5									
		7/8	21,291	20,694	19,836	13,382	13,161			126,953	124,745
		7/11									
		7/14	19,806	20,854	19,888		12,009		125,399		
		7/29	24,065	22,810	20,524	18,168	17,443	14,008	142,225	143,633	135,699
		8/4	21,597	22,589		13,299	14,878		133,418	133,436	123,914
		8/16	20,658	19,932	19,783	11,899	11,729	12,047	129,803	123,513	127,063
		8/19	23,345	23,941	23,758	15,512	17,252	16,776	133,354	133,464	139,650
		8/31	22,269			13,764			133,453		
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/9	23,937	24,074	20,657	16,016	17,114	12,190	131,701	138,388	128,068
		9/18		19,636		13,235	13,614	12,384			
	Autumn	10/12									
		11/5									
		11/11									
Brigantine	Winter	1/15		19,486	19,332						
		1/21									
		1/24									
		2/8									127,381
		2/17		19,851		11,553	11,759		126,240	134,183	127,475
		2/26			19,723			11,881			134,132
		3/1									
		3/4									
		3/7								125,702	
		3/10									
	Spring	5/6									

			ISO-NE			ISO-NY			PJM		
Site	Season	Date	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before
		5/18									
		6/11	19,862			12,101			131,922	124,478	
	Summer	6/23	20,563	19,656		14,263	13,076		137,287	134,545	
		7/2									
		7/8	21,291	20,694	19,836	13,382	13,161			126,953	124,745
		7/20	24,055	21,037		17,842	13,081		143,065	133,567	128,265
		7/29	24,065	22,810	20,524	18,168	17,443	14,008	142,225	143,633	135,699
		8/25	21,473	20,643		12,613	12,127				
		8/31	22,269			13,764			133,453		
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/18		19,636		13,235	13,614	12,384			
	Autumn	12/8									
		12/11									
Great Gulf	Winter	1/12									
		2/20		19,382		11,506	12,061	11,781	143,129	140,386	127,107
		2/23	19,625						127,775		
		3/7								125,702	
	Spring	5/9									
		5/24									
		5/30						12,401			
		6/11	19,862			12,101			131,922	124,478	
	Summer	7/5									
		7/14	19,806	20,854	19,888		12,009		125,399		
		7/20	24,055	21,037		17,842	13,081		143,065	133,567	128,265
		7/29	24,065	22,810	20,524	18,168	17,443	14,008	142,225	143,633	135,699
		8/4	21,597	22,589		13,299	14,878		133,418	133,436	123,914
		8/16	20,658	19,932	19,783	11,899	11,729	12,047	129,803	123,513	127,063
		8/19	23,345	23,941	23,758	15,512	17,252	16,776	133,354	133,464	139,650
		8/31	22,269			13,764			133,453		
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/6						13,337			133,169
		9/9	23,937	24,074	20,657	16,016	17,114	12,190	131,701	138,388	128,068
		9/18		19,636		13,235	13,614	12,384			
	Autumn	10/21									
Lye Brook	Winter	2/8									127,381
		2/14								128,761	
		3/4									
		3/7								125,702	
	Spring	4/18									
		5/9									
		5/27				11,535					
		5/30						12,401			
		6/11	19,862			12,101			131,922	124,478	
	Summer	6/23	20,563	19,656		14,263	13,076		137,287	134,545	
		7/5									
		7/8	21,291	20,694	19,836	13,382	13,161			126,953	124,745
		7/20	24,055	21,037		17,842	13,081		143,065	133,567	128,265
		7/26						11,947		123,129	124,661
		7/29	24,065	22,810	20,524	18,168	17,443	14,008	142,225	143,633	135,699
		8/19	23,345	23,941	23,758	15,512	17,252	16,776	133,354	133,464	139,650
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/6						13,337			133,169
		9/9	23,937	24,074	20,657	16,016	17,114	12,190	131,701	138,388	128,068
		9/18		19,636		13,235	13,614	12,384			
	Autumn	10/21									
		12/11									
Moosehorn	Winter	1/12									
		1/18									
		1/27									
		2/14								128,761	

			ISO-NE			ISO-NY			PJM		
Site	Season	Date	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before	Day Of	Day Before	2 Days Before
		2/23	19,625						127,775		
		2/26			19,723			11,881			134,132
		3/1									
	Spring	4/3									
		5/27				11,535					
		6/11	19,862			12,101			131,922	124,478	
	Summer	7/5									
		7/11									
		7/14	19,806	20,854	19,888		12,009		125,399		
		8/4	21,597	22,589		13,299	14,878		133,418	133,436	123,914
		8/16	20,658	19,932	19,783	11,899	11,729	12,047	129,803	123,513	127,063
		8/19	23,345	23,941	23,758	15,512	17,252	16,776	133,354	133,464	139,650
		8/31	22,269			13,764			133,453		
		9/3	22,465	22,445	21,139	15,955	16,744	15,123	141,210	138,664	138,975
		9/9	23,937	24,074	20,657	16,016	17,114	12,190	131,701	138,388	128,068
		9/18		19,636		13,235	13,614	12,384			
	Autumn	10/12									
		11/11									

Conclusions

Visibility impairment occurs year round at all of the Class I Areas in MANE-VU, though it is more predominate in the summer and, to a lesser extent the winter months – with Brigantine being the opposite having more impairment during the winter (it should be noted that the trend due to winter time nitrates is increasing as sulfate becomes more controlled which is discussed in "Impact of Wintertime SCR/SNCR Optimization on Visibility Impairing Nitrate Precursor Emissions"). HEDDs that occurred on days monitored by the IMPROVE system followed the same seasonal pattern for the three ISOs/RTOs we examined, with the most occurring during the summer, than during the winter, and a few in the spring (no HEDDs occurred during the autumn).

There are noticeable differences between the average peak generation on HEDDs and non-HEDDs and substantial increases in the levels of generation typically lead to increases of emissions of pollutants that impair visibility such as SO2 and NOX. When looking exclusively at HEDDs themselves, the highest of those typically occur during the summer months.

HEDDs more often occurred during the most impaired days in 2015, regardless of which method was being examined, though using the old "worst day" metric resulted in the most HEDDs and most impaired days occurring on the same day. It is also typical for these days, particular in the summer, to be preceded by one or two days which are HEDDs as well. HEDDs rarely occurred during best visibility days in 2015 and at Great Gulf they never occurred during the same days.

When the speciation data on HEDDs is examined there appears to be a strong relationship with high levels of sulfate impairment during the HEDD day, but when HEDDs occur during the winter there is a less clear relationship with either sulfate or nitrate impairment.

Examining back trajectories show that the air masses are moving over the geographies of ISO-NE, ISO-NY, and PJM during HEDDS. Air masses moving over all three ISOs/RTOs , in particular ISO-NE, are moving towards Acadia, Great Gulf, and Moosehorn on HEDDs that happen to also be days of poor visibility. For Lye Brook it is air masses that are moving over ISO-NY and to a lesser extent PJM that are

leading to days with poor visibility. For Brigantine, it is air masses moving over predominately PJM that are leading to days with poor visibility.

Though the data presented is indicative of potential relationship between HEDDs, there are clearly other variables that contribute to impaired visibility, but since the goal of the Regional Haze program is to eliminate all anthropogenic influence on Class I Areas, reducing emissions from units that run on HEDDs should be considered as a control measure, in particular when implemented during the summer.

APPENDIX S

Benefits of Combined Heat and Power Systems for Reducing Pollutant Emissions in MANE-VU States

MANE-VU Technical Support Committee

3/9/2016

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Executive Summary

CHP, or cogeneration, is a general term that refers to converting systems that separately produce heat and electricity to integrated systems that produce both. A traditional system with separate power and heat production can achieve an efficiency of 45%, whereas CHP can achieve efficiencies of 80%. A more advanced type of system called trigeneration uses a single integrated process for heating, electricity, and cooling. In addition to the efficiency benefits associated with CHP, transmission losses are decreased since electricity is now produced closer to the end user. This report examines the benefits of installing cogeneration or trigeneration systems for different applications in the MANE-VU states.

This report incorporates an analysis conducted by ICF international that examined the technical and economic potential for CHP installations on a national basis. The ERTAC EGU tool was then used to estimate criteria pollutant benefits from reduced generation in the power sector.

With the CHP technologies discussed in the paper, increases in CHP penetration would lead to significant decreases in SO_2 pollution in MANE-VU due to displacement of current base load generation. Conversely, there was an increase in onsite NO_X emissions from CHP systems in some of the scenarios examined. Smaller CHP systems would need to meet the NO_X standards outlined in the OTC Stationary Generator Model Rule to have a benefit. Larger systems would have a NO_X emission benefit if lowest achievable emission rates (LAER) were applied.

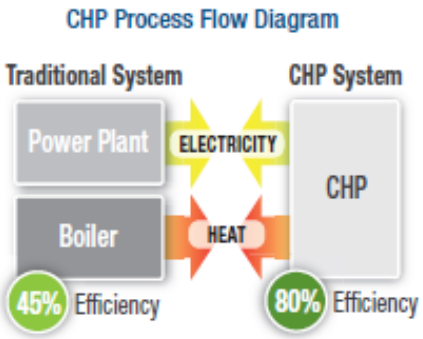
Overview

In November 2012, the Mid-Atlantic North East Visibility Union (MANE-VU) members charged the Technical Support Committee (TSC) with evaluating the potential for combined heat and power strategies to reduce ozone and fine particulate matter levels in MANE-VU states. The TSC was also charged with recommending an appropriate strategy or strategies. In February 2013, the TSC launched the Combined Heat & Power (CHP) Workgroup to fulfill MANE-VU's charge. The workgroup decided to initially focus on the reduction potential for installations and retrofits of commercial and industrial systems with CHP.

Purpose of this report: This report estimates the magnitude of oxides of Nitrogen (NO_X) and Sulfur Dioxide (SO_2) emission reductions possible in MANE-VU from installation and retrofit of commercial and industrial systems with CHP.

Background

CHP, or cogeneration, is a general term that refers to converting systems that separately produce heat and electricity to integrated systems that produce both. A traditional system with separate power and heat production can achieve an efficiency of 45%, whereas CHP can achieve efficiencies of 80% (note: efficiency is defined here as the conversion of fuel to useful energy). A more advanced type of system called trigeneration uses a single integrated process for heating, electricity, and cooling. In addition to the efficiency benefits associated with CHP, transmission losses are decreased since electricity is now produced closer to the end user.



Since CHP systems use the same fuel to produce heat and electricity rather than the traditional separated power plant/boiler system, they also produce fewer emissions. For example, with CHP, an institution would produce a similar level of emissions as it would with just a boiler used for heating, but power no longer needs to be generated elsewhere to meet the institution's electricity needs. So the overall system does not emit the same level of criteria, toxic, and greenhouse pollutants as traditional separate heat-producing and electricity-generating processes.

There are other benefits to the installation of CHP systems. CHP systems can be set up as distributed generation resources, to be called on during times of peak energy needs. In addition, CHP systems can continue to function and provide local power during electrical grid failures. This allows facilities with CHP systems to remain electrified at times when the grid fails due to acts of nature, voltage problems, or blackouts.

There are also challenges to implementation of CHP systems. In a report on CHP produced by Oak Ridge National Laboratory it was stated that "challenges include unfamiliarity with CHP, technology limitations, utility business practices, regulatory ambiguity, environmental

permitting approaches that do not acknowledge and reward the energy efficiency and emissions benefits, uneven tax treatment, and interconnection requirements, processes, and enforcement.[1]" Additionally, since CHP systems are smaller than a conventional electrical generating unit (EGU), emissions from these systems could in some case outweigh the benefits of the reduced offsite electricity production from the grid. There are also many economic factors that could prevent CHP from being feasible. The interactions between fuel prices, electricity prices, potential capacity, physical constraints, and available capital, among other factors, could prevent some CHP capacity from being realized. Regulations also play a role in reducing the amount of economically feasible CHP.

Criteria Pollutant Reduction Potential from Commercial and Industrial Installation & Retrofits of Heating Systems with CHP

Potential for CHP Installation in MANE-VU States

The first step in determining potential emission reductions from CHP installations is to determine how much potential there is for such installations, especially since many states in MANE-VU have existing installed CHP. A report by ICF International examined the technical potential for installation of CHP systems, beyond current installations, on a national basis. This report was relied on for determining the technical potential in the MANE-VU region. Table 1 shows the technical potential for CHP systems in the U.S.

An examination of the benefits of CHP systems in the MANE-VU region was performed by estimating the emissions associated with all technically feasible CHP in MANE-VU as listed in Table 2.

[1] Oak Ridge National Laboratory. "COMBINED HEAT AND POWER Effective Energy Solutions for a Sustainable Future." http://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_report_12-08.pdf. Accessed March 23, 2013.

Table 1: Technical potential (MW) for CHP systems in the U.S. by capacity and application[2]

Sector		Load Factor	Application	Technical Potential (MW)					
				.05-1 MW	1-5 MW	5-20 MW	>20 MW	Total	Class
Cogeneration	Industrial	High	Food & Beverage	2,744	3,250	1,330	697	8,021	63,823
			Textiles	586	751	726	176	2,239	
			Lumber and Wood	1,413	854	332	164	2,763	
			Paper	1,230	1,869	3,601	7,597	14,297	
			Printing/Publishing	2,306	5,875	8,165	8,223	24,569	
			Chemicals	424	897	697	1,941	3,959	
			Petroleum Refining	1,023	314	120	28	1,485	
			Rubber/Misc Plastics	88	122	53	0	263	
			Stone/Clay/Glass	406	532	953	1,214	3,105	
			Fabricated Metals	254	21	6	0	281	
			Transportation Equip.	681	469	725	304	2,179	
			Furniture	44	2	0	0	46	
			Chemicals	173	23	5	0	201	
			Machinery/Cptr Equip	74	62	17	0	153	
			Instruments	76	23	24	0	123	
			Misc Manufacturing	85	20	34	0	139	
	Comm/Inst	High	Waste Water Treatment	111	66	0	0	177	3,242
			Prisons	318	1,343	850	554	3,065	
		Low	Laundries	116	13	0	0	129	612
			Health Clubs	125	26	8	0	159	
			Golf/Country Clubs	235	28	15	0	278	
			Carwashes	43	3	0	0	46	
Trigeneration	Comm/Inst	High	Refrig Warehouses	67	33	9	7	116	21,188
			Data Centers	272	380	339	46	1,037	
			Nursing Homes	765	159	13	0	937	
			Hospitals	892	3,179	769	345	5,185	
			Colleges/Universities	641	1,648	1,669	1,471	5,429	
			Multi-Family Buildings	3,774	1,325	0	0	5,099	
			Hotels	1,330	1,386	460	209	3,385	
		Low	Airports	125	261	290	0	676	43,014
			Post Offices	29	11	0	0	40	
			Food Sales	1,079	65	41	0	1,185	
			Restaurants	1,179	62	15	0	1,256	
			Commercial Buildings	20,378	12,842	0	0	33,220	
			Movie Theaters	3	1	0	0	4	
			Schools	789	87	0	0	876	
			Museums	41	13	0	0	54	
			Government Facilities	1,276	1,334	955	170	3,735	
			Big Box Retail	1,662	251	25	30	1,968	

[2] ICF International. "Effect of a 30 Percent Investment Tax Credit on the Economic Market Potential for Combined Heat and Power." October 2010. Accessed October 29, 2014.

Table 2: Existing and technical potential (MW) for CHP systems in MANE-VU states by capacity

State	Existing (MW)[3]	Technical Potential (MW)[2]				
		.05-1 MW	1-5 MW	5-20 MW	>20 MW	Total
CT	741	492	396	78	0	966
DC[4]	14	0	0	0	0	0
DE	231	104	59	21	0	184
ME	936	176	142	0	6	324
MD	705	682	457	0	75	1,214
MA	1,576	976	755	0	140	1,871
NH	47	184	130	9	0	323
NJ	3,049	1,133	875	421	28	2,457
NY	5,775	2,851	2,671	820	259	6,601
PA	3,269	1,631	1,442	233	155	3,461
RI	126	159	117	22	0	298
VT	24	85	61	19	0	165
Total	16,493	8,473	7,105	1,623	663	17,864

Table 1 examines various CHP applications and whether they: 1) would produce electricity, heating, and cooling (trigeneration) or just electricity and heating (cogeneration), 2) would be used for industrial purposes or commercial/institutional purposes, and 3) run only during business hours (low load factor) or closer to 24 hours a day (high load factor). Data from the ICF analyses was also used to estimate annual operating hours from for systems in each class.

Table 2 includes state level totals of both existing and technical potential by system capacity as found in the ICF report. The technical potential is the basis for the capacity estimates throughout this paper. Since ICF did not analyze Washington, DC, although it has 14 MW of existing CHP capacity, it was excluded from the remainder of the paper.

Since no information was available for technical potential for each class at the state level, it was assumed that each state had the same distribution of classes as was found nationally Equation 1 was used to estimate the technical potential for each class/state/capacity possibility. The resulting distribution that was used throughout the rest of this paper can be found in Table 3.

Equation 1: State/Class/Size Technical Potential

$$PercentageTechPotential_{Class/Size} = (TechPotential_{Class/Size}/TechPotential_{National/Size})$$

[3] https://doe.icfwebservices.com/chpdb/. Accessed September 4, 2015.

[4] Since ICF did not analyze Washington, DC, although it has 14 MW of existing CHP capacity, it was excluded from the remainder of the paper.

Table 3: Percentage of technical potential for each class by capacity in the U.S.

Class	Op. Hours[2]	System Capacity			
		.05-1 MW	1-5 MW	5-20 MW	>20 MW
Cogen/Industrial/High Load	7,000	24.77%	38.09%	75.47%	87.78%
Cogen/Commercial/High Load	7,000	0.92%	3.56%	3.82%	2.39%
Cogen/Commercial/Low Load	4,000	1.11%	0.18%	0.10%	0.00%
Trigen/Commercial/High Load	7,000	16.52%	20.48%	14.65%	8.97%
Trigen/Commercial/Low Load	5,000	56.69%	37.69%	5.96%	0.86%

Additionally, only the CHP systems that are economically feasible were examined. ICF produced three scenarios looking at differing levels of the Investment Tax Credit (ITC) to determine what could be economically feasible (Table 4). Since this information was not available at the state level, it was assumed that each state had the same distribution of classes as was found nationally. The percentage of each size that was found to be economically feasible was applied to each state's technical feasibility for these scenarios.

Table 4: Economic feasibility of CHP at three levels of the ITC in the U.S.[2]

Class	National Capacity (MW)								
	.05-1 MW		1-5 MW		5-20 MW		>20 MW		Total
0% ITC	125	0.27%	371	0.94%	567	2.55%	1,547	6.68%	2,610
Expanded ITC (10% up to 25 MW)	181	0.39%	500	1.26%	674	3.03%	1,802	7.78%	3,157
30% ITC (30% up to 25 MW)	258	0.55%	681	1.72%	973	4.37%	2,284	9.86%	4,196
Technical Potential	46,857		39,600		22,246		23,176		131,879

Potential Emission Reductions

There are two ways in which installation of CHP can change emissions levels, onsite and offsite. The onsite emission changes would be due to retrofits and repowering necessary to convert a system to CHP (for example, a newly installed boiler or turbine that produces different emissions from the previous equipment). Offsite emissions changes would occur because CHP acts as a replacement for electricity produced elsewhere.

Calculations for Estimating Onsite Emission Changes

The breakouts in Table 3 were used to calculate emission reductions by capacity and the class of facility. For each state, emission reductions were calculated for NO_X and SO_2.

Using the same capacity breakout, an assessment conducted by NYSERDA contained emission reductions from replacing a subset of the boilers in their region with natural gas fired CHP systems[5]. Average annual emission rates for existing and replacement systems were calculated

[5] NYSERDA. "Combined Heat and Power Market Potential for New York State." October 2002.

on a per MW basis for NO_X and SO_2 using the base case scenario found in the NYSERDA report (except NO_X emission rates for replacement systems, see below). Since emission rates are not available for systems sized .05-.5 MW in the NYSERDA report, it was assumed that they had the same emission rates as systems sized .5-1 MW.

Instead of relying on the NYSERDA report, several estimates of NO_X emission rates were used when calculating emissions from replacement systems. Systems smaller than 5 MW were assumed to employ Reciprocating Internal Combustion Engines (RICE). Systems larger than 5 MW were assumed to employ Combustion Turbines (CT). Microturbines and fuel cells were also considered for the smaller systems, but these technologies are still evolving and using RICE would result in a more conservative estimate. For systems sized less than 5 MW, Delaware's stationary generator rule was used for Delaware, the OTC 2010 stationary generator model rule was used for New Jersey, and the RICE NSPS was used for all other states.

For systems in the 5-15 MW range, it was assumed that the emission rates from the OTC Model Rule for Additional NO_X Control Measures applied, regardless of state. Also regardless of state, all systems greater than 20 MW used the New Source Performance Standard for CTs. Additionally, average emission rates for the 5-20 MW category were calculated by averaging regulatory values for systems sized 5-15 MW (given 2/3 weight) and 15-20 MW (given 1/3 weight).

However, the emission rates for systems 5 MW and greater would almost certainly trigger New Source Review (NSR) or Prevention of Significant Deterioration (PSD), which would in turn lead to requirements to install the Lowest Achievable Emission Rate (LAER) or Best Available Control Technology (BACT) respectively. In order two find an appropriate BACT emission rate, the workgroup searched the RACT/BACT/LAER Clearinghouse (RBLC) for CHP combustion turbines installed since 2005 that ran on natural gas and were less than 25 MW.

Three units were found in the RBLC that had an emission rate in the appropriate format and that met the criteria – Woodbridge Energy Center (.034 lb/MWh) and Hess Newark Energy Center (0.170 lb/MWh) in New Jersey and Wesleyan University (0.109 lb/MWh) in Connecticut. These units had an average emission rate of 0.105 lb/MWh, considered to be BACT, and a lowest emission rate of 0.034 lb/MWh, considered to be LAER. Given that there are several ozone nonattainment areas in MANE-VU, that many other areas have a history of ozone nonattainment, and that some states in MANE-VU require LAER in attainment areas, the LAER emission rate was applied to the CHP systems in this analysis.

Although units smaller than 5 MW could trigger NSR, the second scenario (which assumes all states have adopted the OTC Stationary Generator Model Rule) should be sufficient to address BACT. Therefore no further analysis was conducted with respect to BACT.

A second set of calculations was made showing what would happen if all MANE-VU states adopted the 2010 stationary generator rule for the replacement systems. This meant that all states, except Delaware, had NO_X emission rates equivalent to those used for New Jersey in the first scenario. Emission factors used in the onsite calculations are summarized in Table 5.

Table 5: Annual average emission rates (lb/MWh) for CHP replacement and existing heating only boilers

Capacity	NO_X				SO_2		*CHP Heat Rate (Btu/kWh)* [2]
	CHP - DE[6]	CHP – OTC M.R.[7]	CHP – Fed.[8]	Existing	CHP	Existing	
.05-.5 MW	0.60	0.88	2.96	-	-	-	10,800
.5-1 MW	0.60	0.88	2.96	0.6355	0.0062	0.0031	10,800
1-5 MW	0.60	0.88	2.96	0.8246	0.0070	0.0028	9,492
5-20 MW[9][10]	1.87/0.034	1.87/0. 034	1.87/0. 034	0.7750	0.0069	0.0027	11,765
> 20 MW[10]	1.20/0. 034	1.20/0. 034	1.20/0. 034	0.5546	0.0055	0.0022	9,220

The systems were assumed to run according the annual operating hours listed in Table 3. It should be noted that the replacement systems themselves produce more emissions than the original systems.

Calculations for Estimating Offsite Emission Changes

As discussed earlier, the other way in which CHP systems can reduce pollution is by reducing the amount of electricity that power plants need to produce.

Several assumptions were made in order to estimate the emission reductions from the power sector due to implementation of CHP:

- For each state, CHP systems would replace base load coal generation in the ERTAC region in which the state was predominately located. In regions where coal generation does not occur, the system would replace Combined Cycle Natural Gas units. The coal assumption in particular could lead to an overstatement of the benefits.
- Transmission loss would be the average in the Eastern Interconnection of 5.82%.
- Although CHP systems would undertake routine maintenance during shoulder months, this activity will have a negligible effect on emission estimates.
- New CHP systems will be operational by the modeled future year of 2018, which was chosen due to its importance for Ozone and Regional Haze planning.

To calculate the number of hours that the low load factor cogeneration CHP systems would run during the year, the number of heating degree days and cooling degree days were averaged from 2004-2013 for each of month of the year. The ratio of heating degree days to total degree days was used to approximate the number of hours in the month the heating system would run (heating hours).

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[6] DE 7 § 1144 3.2.2
[7] OTC Model Rule for Stationary Generator Control Measures.
[8] 40CFR60-JJJJ
[9] OTC Model Rule for Additional Nitrogen Oxides (NOx) Control Measures
[10] 40CFR60-KKKK

In order to estimate the start and end of the heating season, the shoulder months were examined to determine which had the clearest end date-and then the average annual heating hours were used to calculate the other date based on the assumption that the heating would run straight through. An overview of the heating/cooling degree days and heating hours are in Table 5, as well as the approximate dates used as the end and beginning of the heating season for each state.

Table 6: Average annual heating and cooling degree days, last and first date of heating season, and calculated hours for heating by state from 2004-2013[11]

State	Annual Average Degree Days		Heating Season		Heating Hours
	Heating	Cooling	Last Day	First Day	
CT	5,780	625	6/7	9/14	6,386
DE	4,414	1,210	5/17	9/27	5,545
MA	6,043	534	6/14	9/12	6,622
MD	4,497	1200	5/17	9/27	5,568
ME	7,622	236	7/22	8/19	7,563
NH	7,327	310	6/20	8/21	7,268
NJ	5,045	913	5/23	9/19	5,900
NY	5,909	647	6/7	9/14	6,405
PA	5,623	734	5/24	9/7	6,208
RI	5,682	585	6/15	9/18	6,488
VT	7,778	249	6/22	8/13	7,498

The ERTAC EGU tool was then used to estimate the emission reductions from reduced need for generation in the power sector. Version 2.3 of the ERTAC inputs was used as the basis for the runs and the runs were conducted using a modified copy of version 1.01 of the software. The modifications were made to limit the number of hours that units could be run based on the utilization factor.

To use ERTAC EGU to project CHP's impacts on the grid, a "virtual CHP plant" was created for: 1) each state (three in the case of New York), 2) each class of facilities, 3) the four tiers of capacities, and 4) in the case of the CHP low load class, each season. This resulted in a total of 364 "virtual CHP plants." The scenario in which all of the technically feasible CHP systems are built will be henceforth called "Technical Potential Scenario". In addition, the benefits of only installing larger systems (those greater than or equal to 5 MW) and of only installing smaller systems (those less than 5 MW) were examined. These cases are henceforth called "Large Systems Scenario" and "Small Systems Scenario," respectively. Finally, the three economic options, "0% ITC Scenario," "10% ITC Scenario," and "30% ITC Scenario" were assessed.

ERTAC EGU distributes generation using geographic regions that are based on the regions used by the Energy Information Agency in their Annual Energy Outlook report. In most cases the

[11] NCDC Climate Indicators. http://www7.ncdc.noaa.gov/CDO/CDODivisionalSelect.jsp. Accessed April 11, 2014.

entirety of the MANE-VU state is within the applicable ERTAC region so 100% of the virtual CHP systems are allocated to that region. Even though part of western Pennsylvania, and to a lesser extent part of western Maryland, is in the RFCW region, all of the CHP systems were allocated to the RFCE region since the RFCW region extends well beyond the MANE-VU region. New York has three regions. To allocate the CHP systems across those regions, the percentage of the population from 2010 US Census data in each region was used as a surrogate[12]. A map of all of the ERTAC regions is in Figure 1 and the list of regions analyzed is in Table 7.

Figure 1: Map of ERTAC Regions

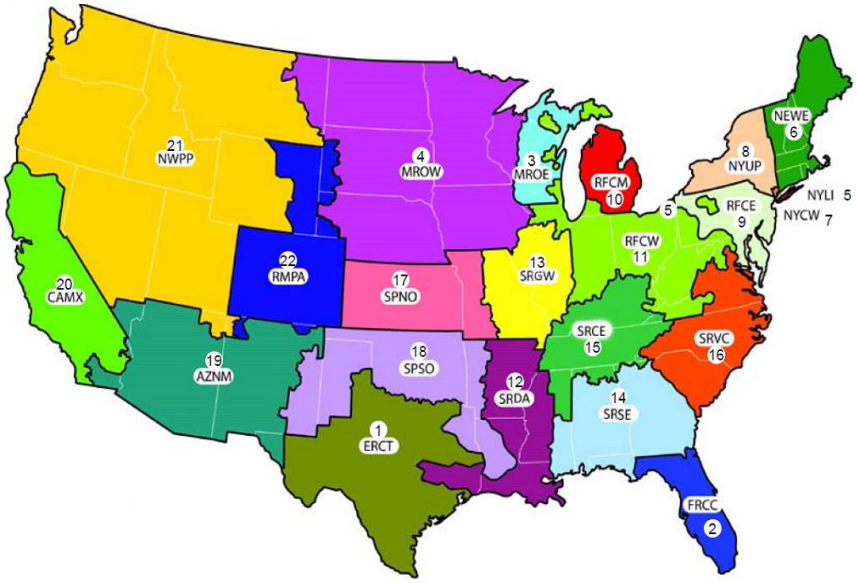

Table 7: List of ERTAC EGU regions analyzed and which states are allocated to the regions

ERTAC EGU Region	State Allocation
NEWE	100% of CT, ME, MA, ME, NH, RI, VT
NYCW	42% of NY
NYLI	15% of NY
NYUP	43% of NY
RFCE	100% of DE, MD, NJ, PA

The ERTAC EGU input files must contain several data elements to process the "virtual CHP plants":

1. Capacity: calculated using Equation 2 using the distributions from Table 3.
2. Annual heat rate: based on the capacity tier, obtained from the ICF report and listed in Table 5.

[12] http://www.census.gov/popest/data/counties/totals/2014/CO-EST2014-01.html. Accessed August 6, 2015.

3. Utilization fraction (percentage of hours operating): The operating hours, based on the class obtained from the ICF report, are listed in Table 3. For the low load cogeneration class, the utilization fraction was the same as that used for low load trigeneration facilities for the non-summer months and was adjusted accordingly for the summer months using the length of the heating season defined in Table 5.
4. Maximum heat input: calculated using Equation 3.
5. NO_X and SO_2 emission rates: set to 0 since the onsite emissions were calculated separately.

Equation 2: "Virtual CHP plant" capacity

$$Capacity_{Virtual\ Plant} = PercentageTechPotential_{Class/Size}/TechPotential_{State/Size}/(1\text{-}TransLoss)$$

Equation 3: "Virtual CHP plant" maximum heat input

$$Maximum\ Heat\ Input = Annual\ Heat\ Rate * Capacity_{Class/State/Size}/1000$$

Additionally, to properly shutdown the "virtual CHP plants" during hours which they are not running, the ERTAC EGU code was altered so that systems do not run after the maximum number of hours was met. The maximum number of hours is based on the utilization fraction.

Results

When looking at the scenarios that examined technical potential only, the replacement of boilers in MANE-VU with CHP systems would yield substantial increases in onsite NO_X if the model rule is not adopted by all of the states. These emission increases outweigh the benefits of reduced power needed from the grid. Implementing the model rule would lead to regional NO_X benefits. Using BACT emission limits for the large systems, which are independent of the model rule, has a positive impact on NO_X emissions. In all situations the implementation of CHP systems has a clear SO_2 benefit. Table 8 summarizes the changes in onsite and offsite NO_X and SO_2 for all of the scenarios analyzed.

For the systems that ICF found to be economical at the various ITC levels, the emission changes increase at higher ITC levels. This is an expected trend. Having the model rule implemented throughout MANE-VU resulted in NO_X benefits at all levels of the ITC, whereas all of the scenarios without full implementation of the model rule resulted in NO_X increases. In all cases there was a benefit in reduced SO_2.

More details on the changes in emissions are in Table 9.

Table 8: Changes in NO_X and SO_2 annual emissions (tons) in the MANE-VU region as a result of CHP replacement

Scenario		Pollutant	Total	Scenario		Pollutant	Total
"Technical Potential"	Onsite	**NO_X - no Model Rule**	85,993	"30% ITC"	Onsite	NO_X - no Model Rule	686
		NO_X - w/ Model Rule	1,819			NO_X - w/ Model Rule	-246
		SO_2	201			SO_2	4
	Offsite	**NO_X**	-28,894		Offsite	NO_X	-295
		SO_2	-64,628			SO_2	-1,303
	Total	**NO_X - no Model Rule**	57,098		Total	NO_X - no Model Rule	390
		NO_X - w/ Model Rule	-27,075			NO_X - w/ Model Rule	-542
		SO_2	-64,427			SO_2	-1,299
	CHP Capacity (MW)		17,680		CHP Capacity (MW)		303
"Large Units"	Onsite	**NO_X**	-5,342	"10% ITC"	Onsite	NO_X - no Model Rule	495
						NO_X - w/ Model Rule	-181
		SO_2	31			SO_2	3
	Offsite	**NO_X**	-1,912		Offsite	NO_X	-211
		SO_2	-9,653			SO_2	-947
	Total	**NO_X**	-7,254		Total	NO_X - no Model Rule	284
						NO_X - w/ Model Rule	-392
		SO_2	-9,623			SO_2	-944
	CHP Capacity (MW)		2,265		CHP Capacity (MW)		221
"Small Units"	Onsite	**NO_X - no Model Rule**	91,334	"0% ITC"	Onsite	NO_X - no Model Rule	334
		NO_X - w/ Model Rule	7,160			NO_X - w/ Model Rule	-159
		SO_2	170			SO_2	2
	Offsite	**NO_X**	-12,804		Offsite	NO_X	-161
		SO_2	-58,066			SO_2	-737
	Total	**NO_X - no Model Rule**	78,230		Total	NO_X - no Model Rule	174
		NO_X - w/ Model Rule	-5,644			NO_X - w/ Model Rule	-319
		SO_2	-57,895			SO_2	-735
	CHP Capacity (MW)		15,415		CHP Capacity (MW)		173

Conclusions

With the CHP technologies discussed in this paper, increases in CHP penetration would lead to significant decreases in SO_2 emissions in MANE-VU due to displacement of current base load generation. The same is not true for NO_X emissions, given the increase in onsite NO_X emissions from CHP systems in the vast majority of the scenarios examined. When looking at smaller systems, the replacements need to meet the NO_X standards outlined in the OTC Stationary Generator Model Rule to have a benefit.

Although not specifically addressed in this paper, increased CHP penetration would likely produce the additional benefit of reduced SO_2 emissions. This is an additional consideration that decision-makers should examine when pursuing policies to encourage CHP installations. Finally, there are potential newer technologies on the horizon such as fuel cells. These

technologies could reduce the onsite emissions footprint further which would result in more emissions reductions, in particular from NO_X.

Recommendations for Future Work

One limitation of using the ERTAC EGU tool is that economics is not considered on a unit by unit basis, which creates a challenge in ensuring that the CHP systems replace generation from economically marginal units. Additionally, ERTAC EGU segregates generation by fuel further adding to the challenges of only reducing generation from marginal units. Although the technique of creating the "virtual CHP plant" attempted to solve this problem, it would be advisable to attempt using other more appropriate tools in any future analysis. Work is underway to explore incorporating ERTAC EGU projections into the EPA's AVERT (AVoided Emissions and geneRation Tool) model, which is designed to show the impact of renewables and other unconventional generation on the grid. Once that work is complete, the AVERT tool could be very useful for examining the impact of CHP systems in MANE-VU replacing marginal units and peaking units.

Table 9: Changes in NO_X and SO_2 annual emissions (tons) in MANE-VU as a result of CHP replacement

Scenario		Emission Changes													
		Pollutant	CT	DE	DC	ME	MD	MA	NH	NJ	NY	PA	RI	VT	Total
"Technical Potential"	Onsite	NO_X - no Model Rule	5,792	-106	0	2,137	7,548	11,430	2,099	-162	34,665	19,843	1,807	939	85,993
		NO_X - w/ Model Rule	222	-106	0	140	430	576	132	-162	-57	542	78	23	1,819
		SO_2	11	2	0	4	13	20	4	28	76	39	3	2	201
	Offsite	NO_X	-388	-215	0	0	-6,230	-716	-2,677	-1,180	-4,626	-12,863	0	0	-28,894
		SO_2	-540	-561	0	0	-11,265	-1,508	-3,389	-1,315	-20,786	-25,262	0	0	-64,628
	Total	NO_X - no Model Rule	5,405	-320	0	2,137	1,318	10,713	-578	-1,342	30,040	6,980	1,807	939	57,098
		NO_X - w/ Model Rule	-166	-320	0	140	-5,799	-141	-2,545	-1,342	-4,682	-12,321	78	23	-27,075
		SO_2	-530	-559	0	4	-11,252	-1,488	-3,386	-1,287	-20,710	-25,223	3	2	-64,427
	Capacity (MW)		966	0	0	324	1,214	1,871	323	2,457	6,601	3,461	298	165	17,680
"Large Units"	Onsite	NO_X	-199	-54	0	-11	-136	-254	-23	-1,124	-2,561	-876	-56	-48	-5,342
		SO_2	1	0	0	0	1	2	0	6	15	5	0	0	31
	Offsite	NO_X	9	-14	0	1	-285	-235	240	-94	-565	-970	0	0	-1,912
		SO_2	108	-76	0	0	-1,519	-1,394	491	-237	-4,762	-2,265	0	0	-9,653
	Total	NO_X	-189	-68	0	-10	-421	-489	218	-1,218	-3,126	-1,846	-56	-48	-7,254
		SO_2	109	-75	0	0	-1,518	-1,392	491	-230	-4,748	-2,259	0	0	-9,623
	Capacity (MW)		78	0	0	6	75	140	9	449	1,079	388	22	19	2,265
"Small Units"	Onsite	NO_X - no Model Rule	5,991	-52	0	2,148	7,684	11,684	2,122	962	37,226	20,718	1,863	987	91,334
		NO_X - w/ Model Rule	421	-52	0	151	567	830	155	962	2,504	1,417	134	72	7,160
		SO_2	10	2	0	3	12	19	3	22	61	34	3	2	170
	Offsite	NO_X	-191	-102	0	1	-2,004	-256	-782	-514	-2,212	-6,744	0	0	-12,804
		SO_2	-540	-491	0	0	-9,892	-1,508	-3,390	-1,158	-19,257	-21,831	0	0	-58,066
	Total	NO_X - no Model Rule	5,800	-154	0	2,149	5,680	11,428	1,340	448	35,015	13,974	1,863	987	78,530
		NO_X - w/ Model Rule	230	-154	0	151	-1,437	574	-628	448	293	-5,326	134	72	-5,644
		SO_2	-531	-489	0	3	-9,880	-1,489	-3,386	-1,136	-19,196	-21,797	3	2	-57,895
	Capacity (MW)		888	0	0	318	1,139	1,731	314	2,008	5,522	3,073	276	146	15,415
"30% ITC"	Onsite	NO_X - no Model Rule	55	-3	0	22	64	98	21	-45	275	173	17	8	686
		NO_X - w/ Model Rule	-6	-3	0	0	-9	-19	0	-45	-119	-43	-1	-2	-246
		SO_2	0	0	0	0	0	0	0	1	2	1	0	0	4
	Offsite	NO_X	-7	-1	0	1	-40	-11	-47	-8	-63	-119	0	0	-295
		SO_2	-28	-11	0	0	-209	-71	-149	-35	-547	-254	0	0	-1,303
	Total	NO_X - no Model Rule	48	-4	0	22	25	87	-26	-53	212	54	17	8	390
		NO_X - w/ Model Rule	-13	-4	0	1	-49	-30	-47	-53	-182	-162	-2	-2	-542
		SO_2	-28	-10	0	0	-209	-71	-149	-34	-545	-253	0	0	-1,299
	Capacity (MW)		13	0	0	4	19	32	4	42	123	59	4	2	303
"10% ITC"	Onsite	NO_X - no Model Rule	40	-2	0	16	46	69	15	-31	200	124	12	6	495
		NO_X - w/ Model Rule	-4	-2	0	0	-8	-15	0	-31	-86	-32	-1	-1	-181
		SO_2	0	0	0	0	0	0	0	0	1	1	0	0	3
	Offsite	NO_X	-5	0	0	1	-29	-8	-34	-5	-46	-86	0	0	-211
		SO_2	-21	-8	0	0	-153	-51	-108	-25	-399	-183	0	0	-947
	Total	NO_X - no Model Rule	36	-2	0	16	17	62	-19	-36	154	38	12	6	284
		NO_X - w/ Model Rule	-9	-2	0	0	-37	-23	-34	-36	-132	-118	-1	-1	-392
		SO_2	-21	-8	0	0	-152	-51	-108	-25	-397	-182	0	0	-944
	Capacity (MW)		9	0	0	3	14	24	3	30	90	44	3	2	221
"0% ITC"	Onsite	NO_X - no Model Rule	29	-2	0	11	32	48	11	-27	134	86	9	4	334
		NO_X - w/ Model Rule	-3	-2	0	0	-7	-14	0	-27	-75	-28	-1	-1	-159
		SO_2	0	0	0	0	0	0	0	0	1	0	0	0	2
	Offsite	NO_X	-3	0	0	1	-23	-6	-26	-2	-36	-66	0	0	-161
		SO_2	-16	-6	0	0	-119	-38	-82	-20	-315	-141	0	0	-737
	Total	NO_X - no Model Rule	25	-2	0	12	9	42	-15	-30	98	20	9	4	174
		NO_X - w/ Model Rule	-7	-2	0	0	-30	-20	-26	-30	-111	-95	-1	-1	-319
		SO_2	-16	-6	0	0	-119	-38	-82	-20	-314	-141	0	0	-735
	Capacity (MW)		7	0	0	2	11	19	2	24	71	34	2	1	173

APPENDIX T

GRANITE SHORE POWER

August 31, 2018

Mr. Craig Wright, Director
NHDES Air Resources Department
29 Hazen Drive, Concord, NH

GSP's Response to DES' Request for Information on MANE-VU "Ask" Associated with the Regional Haze Rule

I. Introduction

Granite Shore Power LLC (GSP) submits this response to the New Hampshire Department of Environmental Services' (DES) Request for Information (RFI) related to the Mid-Atlantic Northeast Visibility Union (MANE-VU) "Ask" associated with the regional haze rule. While GSP understands that the MANE-VU "Ask" is directed at member states, GSP appreciates the opportunity to be engaged in the process of reviewing emission control strategies at each of its operating facilities. DES submitted the comprehensive RFI to GSP on May 3, 2018. The deadlines in the original RFI were revised, as confirmed on June 15, 2018 via email from Ms. Catherine Beahm, Air Permits Program Manager. On June 25, 2018, GSP submitted a NOx RACT analysis for Schiller Station to satisfy a portion of the RFI. This current submittal satisfies the remaining portion of the RFI (MANE-VU "Ask") and is being submitted by the revised deadline of August 31, 2018.

II. Background

The Clean Air Act and Regional Haze rule (40 CFR 51.308 (f)(2)(i) through (iv) requires states that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment. As part of the New Hampshire regional Haze State Implementation Plan (SIP), NH must consider emission reduction measures identified by Class I States as being necessary to make reasonable progress in any Class I area. DES is part of the MANE-VU, in which the member states work collaboratively to develop emission control strategies to address visibility impairment in Class I areas. On August 25, 2017, MANE-VU issued a statement in which six emission management strategies were proposed in order to meet the 2028 reasonable progress goal for regional haze.

III. Schiller Station

Schiller Station is a wood and fossil fuel-fired electricity generating facility owned and operated by GSP Schiller LLC, a wholly owned subsidiary of Granite Shore Power. The facility includes three

utility boilers: one wood and fossil fuel-fired boiler (designated as Unit 5) and two fossil fuel-fired (residual oil and coal) boilers (designated as Unit 4 and Unit 6). All three boilers are equipped with oxygen trim systems. Each boiler stack is equipped with a continuous emissions monitoring system (CEMS) and a continuous opacity monitoring system (COMS). The facility also includes one combustion turbine (designated as emission unit SRCT).

A. NOx Control Strategies

DES has requested that GSP evaluate the most effective use of the current NOx control strategies for Units 4, 5, and 6 and to perform a four factor analysis for reasonable installation or upgrade to emission controls for the combustion turbine (SRCT).

i. Unit 4 and Unit 6

Units 4 and 6 are equipped with low-NOx burners, selective non-catalytic reduction ("SNCR") systems, and overfire air systems ("OFA") to control NOx emissions. The SNCR systems for units 4, 5, and 6 are fed from a common reagent storage tank system containing a 50 percent solution (as received) of urea.

Unit 4 and Unit 6 are dry-bottom wall-fired boilers that began operation in the 1950's rated at approximately 48 MW each. The boilers were retrofitted in mid-1999 with RJM Corporation's low NOx burner modifications. Baseline NOx levels prior to the burner modifications were up to 1.0 lb/MMBtu[1]. The burner modifications reduced NOx emissions by approximately 50 percent to 0.4 to 0.5 lb/MMBtu. The former owner, Public Service Company of New Hampshire (PSNH), sold NOx allowances to fund the installation of a NOxOUT™ SNCR system on Units 4, 5, and 6 in late 1999. The SNCR system was designed to achieve an additional 30 to 35 percent NOx reduction to 0.33 lb/MMBtu at loads of 80 to 100 percent. In the early 2000s, OFA systems were installed to further reduce NOx emissions. The OFA systems are comprised of ports, ducts, and dampers that allow up to 15 percent of the combustion airflow to be diverted from the top of the windbox through ports located above the top elevation of burners.

Units 4 and 6 were historically operated as base-loaded units. In the last few years, due to the increased supply of natural gas to the region, the units have operated at significantly lower capacity factors annually. Therefore, the units operate significantly fewer hours annually with significantly fewer emissions. Specifically, the capacity factor has decreased from 84% to 8% on Unit 4 and from 75% to 7% on Unit 6 between 2007 and 2017.

As DES is aware, Schiller Station has aggressively reduced NOx emissions for over 20 years. Schiller Station currently implements cost-effective combustion control technologies (low NOx burners, OFA) that achieve cumulative NOx reductions of up to 70 percent from baseline (see footnote 1) NOx levels. In fact, Unit 4 and 6 NOx emissions continue to be approximately 40 percent below the existing applicable daily NOx RACT limits of 0.5 lb/MMBtu.

At the request of DES, GSP performed a NOx RACT analysis to evaluate the technical and economic feasibility of achieving certain levels of NOx reduction while operating the SNCR on Units 4 and 6. The results of the analysis were submitted to DES on June 25, 2018. The analysis demonstrated that NOx emission limits more stringent than 0.25 lb/MMBtu are not technologically or economically feasible for Units 4 and 6 and would result in a high cost despite minimal overall mass NOx reductions. As a result, DES proposed NOx RACT Order (RO-003) on July 13, 2018 for Units 4 and 6. The proposed NOx RACT Order contains a NOx emission limit of 0.25 lb/MMBtu on a 24-hour calendar day average, including all hours of operation for Unit 4 and Unit 6. The NOx RACT Order will become effective upon final issuance by DES, pending public comments. GSP intends to maintain NOx emissions below these limits through use of low NOx burners, OFA, and cost-effective SNCR use on an as-needed basis.

The pending NOx RACT Order will establish limits consistent with the most-effective use of the NOx controls for Units 4 and 6.

ii. Unit 5

Unit 5 is a circulating fluidized bed (CFB) wood-fired boiler equipped with a SNCR system to control NOx emissions. Unit 5's NOx emissions are limited to 0.075 lb/MMBtu on a 24-hour calendar day basis pursuant to NOx RACT Order ARD-06-001 issued by DES on August 4, 2006. The limit was established as a result of a NOx RACT analysis of the technological and economic feasibility of NOx control techniques, including low NOx burners, OFA, flue gas recirculation, natural gas reburn, burners out of service, use of alternative fuels, SCR and SNCR. The former owner, PSNH, ultimately proposed the use of SNCR paired with CFB technology, which is recognized as a low emission, advanced solid fuel combustion technology. The formation of NOx in the CFB boiler is reduced as a result of the low combustion temperatures and low excess air within the fluidized bed.

[1] Based on several references to the baseline NOx rates of 0.8 to 1.0 lb/MMBtu in internal historical documents. Also noted in July 28, 1992 version of NOx RACT Emission Limits Part Env-A 1210 as baseline NOx 0.675 to 0.990 lb/MMBtu based on single test points July 6 to 8, 1992.

The only other technologically feasible option, SCR, was not economically feasible because of increased costs that would be associated with pretreatment of particulate matter.

Unit 5's NOx limit was ultimately established based on design specifications and emission data provided by the boiler manufacturer. The limit is representative of emissions during normal or stable operations, however the limit is not suitable for periods of startup or shutdown, as SNCR systems will not be allowed to operate until the defined minimum boiler load and temperature are reached[2]. As such, PSNH and DES reviewed actual emissions data for a period of at least one year to determine an emission limit that could reasonably be achieved during startup and shutdown periods. The current NOx limit for startup and shutdown periods is 0.15 lb/MMBtu for up to two calendar days per event.

The existing limits represent the most effective use of the control technology, as assessed by PSNH and DES following commissioning of the Unit 5 boiler and SNCR system. The current limits require year-round use of the SNCR.

A summary of RACT/BACT/LAER Clearinghouse data is provided in Attachment A for NOx control on wood-fired boilers. The summary illustrates that Unit 5's NOx limit of 0.075 lb/MMBtu is the lowest emissions limit listed for similar sized units. Not only does it compare (or supersede) the limits of equivalent size wood boilers (two being explicitly called out as circulating fluidized beds) being controlled by SNCR, but it is also equivalent to one of similar size, being controlled with an SCR.

iii. SRCT

A four-factor analysis for reasonable installation or upgrade to NOx emission controls was performed for SRCT. The analysis is included as Attachment B. The analysis indicated that there were no technologically and economically feasible control options available for the combustion turbine. Alternatively, GSP will continue to look for opportunities to employ good combustion practices, such as the recently upgraded control system with improved fuel control valve and routine inspections in accordance with manufacturer recommendations.

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2 https://cdn.ymaws.com/www.icac.com/resource/resmgr/MATS_decision/MATS_SS_Guidance_Document_Fi.pdf

B. Acid Gas Control Strategies

DES has requested that GSP evaluate the most effective use of the current acid gas control strategies for Units 4, 5, and 6.

i. Unit 4 and Unit 6

Units 4 and 6 are equipped with dry sorbent injection (DSI) systems to control emissions of acid gases. The DSI systems were installed for the purpose of complying with 40 CFR 63 Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units (Mercury and Air Toxics Standards or MATS). The DSI systems are intended to reduce concentrations of hydrochloric acid (HCl). As a co-benefit, the DSI system reduces concentrations of sulfur oxides including SO2.

GSP currently performs quarterly stack testing for HCl as required by the MATS rule. GSP must operate the DSI system year-round at or above the average injection rate observed during the most recent stack test for HCl. Less frequent performance testing is required of units that achieve Low Emitting EGU (LEE) status. LEE status is achieved after 3 consecutive years of required quarterly tests are performed with resulting emissions less than 50 percent of the allowable emission rate of 0.002 lb/MMBtu. All stack tests performed to date on Units 4 and 6 have resulted in HCl emissions less than 50 percent of the emission limit and both units are nearing completion of the 3 year period that would qualify them for LEE status with reduced test frequency.

Additionally, in 2016 as a result of the 2010 1-hour SO2 National Ambient Air Quality Standard (NAAQS), Schiller Station submitted to DES modeling of actual existing emissions and proposed potential emissions showing compliance with the 1-hr SO2 standard. Existing local monitoring data also provided abundant evidence that the existing limits were adequate to prevent significant deterioration and to maintain the NAAQS in both New Hampshire and Maine. DES ultimately proposed a new daily SO2 limit for Schiller Station Units 4 and 6 of 0.83 lb/MMBtu. This current SO2 limit is achieved through a combination of low sulfur coal and operation of the DSI system.

Since the DSI system is already required to operate at a set minimum rate to reduce HCl emissions, the SO2 emissions are managed by automatically injecting incremental additional sorbent using emissions feedback from the SO2 CEMS.

Units 4 and 6 comply with the most current and strict federal standards for acid gases: MATS HCl limit and 1-hr SO2 NAAQS. Schiller station implements the most effective use of the existing control technology, which is year-round operation of the DSI system, as applicable, targeting reduction of multiple acid gases. Due to operational and cost considerations, the DSI system is operated effectively, to comply with strict federal standards without over-injecting sorbent material. For instance, Schiller Station works diligently to balance operation of the DSI system with operation of other emission controls to avoid adverse impacts on mercury capture or overloading the electrostatic precipitator with particulate matter.

ii. Unit 5

Unit 5 was converted to a wood-fired boiler in 2006. Since Unit 5 is also permitted to burn coal, DES has requested that GSP evaluate the most effective use of limestone injection to reduce SO2 emissions from coal combustion. Unit 5 has only fired coal for the purpose of collecting performance test data in 2006 during commissioning of the boiler. Since the initial testing was limited and Unit 5 has not fired coal for approximately 12 years, GSP is unable to evaluate the most effective use of the limestone injection system for SO2 emission reductions from coal combustion.

However, GSP does assert that the current daily permit limit of 0.12 lb SO2/MMBtu for coal firing based on New Source Performance Standards for EGU's (40 CFR 60.43Da(a)) is sufficiently stringent to assist DES with meeting the state's reasonable progress goals for regional haze in the event of coal firing on Unit 5. The existing limit is even more stringent than other current federal standards for acid gases from coal-fired EGUs (i.e., MATS 0.2 lb/MMBtu SO2 proxy for HCl limit).

IV. Merrimack Station

Merrimack Station is a fossil fuel-fired electricity generating facility owned and operated by GSP Merrimack LLC, a wholly owned subsidiary of Granite Shore Power. Merrimack Station is comprised of two bituminous coal-fired utility boilers (designated as Unit 1 and Unit 2) and two combustion turbines operating as load shaving units. Each boiler duct is equipped with a CEM system to measure NOx, SO2, CO2, stack flow, and opacity. The common stack (for Units 1 and 2) is equipped with a CEM system to measure NOx, SO2, CO2, stack flow, and also a sorbent trap monitoring system to measure Hg.

A. NOx Control Strategies

DES has requested that GSP evaluate the most effective use of the current NOx control strategies for Unit 1 and to perform a four-factor analysis for reasonable installation or upgrade to emission controls for Unit 2 and the two combustion turbines (MKCT1 and MKCT2).

i. Unit 1

Unit 1 is equipped with a selective catalytic reduction ("SCR") system to control NOx emissions. DES recently reviewed historical performance data for Unit 1 and revised the NOx RACT rules in Env-A 1300 with more stringent daily NOx emission limits on both a rate basis and a mass basis. The new daily NOx limits, effective August 15, 2018, for Unit 1 are 0.22 lb/MMBtu when SCR temperature permissive parameters are met for all operating time in the day, or 4.0 tons per day when any startup, shutdown, or low-load conditions occur in the day (flue gas temperatures below SCR operating temperature). These recently revised NOx RACT limits represent the most effective use of the SCR, given that the system must be operated year-round at or above its design capacity to demonstrate compliance.

ii. Unit 2

Unit 2 is equipped with a selective catalytic reduction ("SCR") system to control NOx emissions. DES recently reviewed historical performance data for Unit 2 and revised the NOx RACT rules in Env-A 1300 with more stringent daily NOx emission limits on both a rate basis and a mass basis. The new daily NOx limits, effective August 15, 2018, for Unit 2 are 0.22 lb/MMBtu when SCR temperature permissive parameters are met for all operating time in the day, or 11.5 tons per day when any startup, shutdown, or low-load conditions occur in the day.

Unit 2 is also still subject to the provisions of Env-A 2300 for the mitigation of regional haze, which established a Best Available Retrofit Technology (BART) control strategy to limit NOx to 0.30 lb/MMBtu on a 30-day rolling average basis for all hours of operation. BART is defined as "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility." The BART emission limitation was established on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

The BART control strategy combined with recently revised NOx RACT limits represent the most effective use of the SCR, given that the system must be operated year-round at or above its design capacity to demonstrate compliance.

Further, a four-factor analysis for installation or upgrade to emission controls is unnecessary because Unit 2 has been operating the most effective control technology for nearly 20 years. GSP has already stated in its May 25, 2018 comment letter on the proposed NOx RACT rule revisions that Unit 2 would not be a viable candidate for retrofit with additional NOx controls. Control mechanisms, such as fuel switching or over-fire air cannot be technologically or economically justified, as the additional reductions achievable from these strategies are minimal when installed after the SCR. Moreover, these controls cannot be physically added to the units at Merrimack Station because they would cause operational issues and reduce the efficiency of other pollution control devices. For example, fuel switching for Merrimack Station would mean firing sub-bituminous coal. Although the units are not permitted to burn sub-bituminous coal, if this lower rank fuel was used, it would result in a loss of boiler efficiency and a probable increase in heat rate. This would require Merrimack Station to burn more fuel, causing an increase in emissions. It would also impact Merrimack Station's mercury capture and the efficiency of the precipitator. Overall, this fuel would not provide reliable unit operations and would not be considered a viable alternative to the current use of bituminous coal.

Over-fire air also poses several issues and is an unacceptable solution. The negative impacts include reduced boiler performance, potential boiler modifications to boiler surface areas, increased fouling, boiler tube erosion, and cyclone wear. Any installation is complicated by, if not impossible, due to the engineering and design challenges of the windbox configuration and screen tubes at Merrimack. In addition, the installation of an OFA system after the installation of an SCR is likely to produce little to no improvement in NOx reductions. Any of these changes would also have the potential to negatively impact the removal capability of the FGD and the collection capability of the ESPs.

iii. MKCT1

A four-factor analysis for reasonable installation or upgrade to NOx emission controls was performed for MKCT1. The analysis is included as Attachment B. The analysis indicated that there were no technologically and economically feasible control options available for the combustion turbine. Alternatively, GSP will continue to look for opportunities to employ good combustion practices, such as the recently upgraded control system with improved fuel control valve and routine inspections in accordance with manufacturer recommendations.

iv. MKCT2

A four-factor analysis for reasonable installation or upgrade to NOx emission controls was performed for MKCT2. The analysis is included as Attachment B. The analysis indicated that there were no technologically and economically feasible control options available for the combustion turbine. Alternatively, GSP will continue to look for opportunities to employ good combustion practices, such as the recently upgraded control system with improved fuel control valve and routine inspections in accordance with manufacturer recommendations.

B. SO2 Control Strategies

DES has requested that GSP evaluate the most effective use of the current SO2 control strategies for Unit 1 and to perform a four-factor analysis for reasonable installation or upgrade to emission controls for Unit 2.

v. Unit 1 and Unit 2 (common SO2 control)

A common wet limestone-based flue gas desulfurization (FGD) system controls mercury with a co-benefit of acid gas emissions reductions from Unit 1 and Unit 2. The FGD system is equipped with an emergency cooling pump engine which powers a cooling water pump to provide cooling water to the FGD system during emergency situations such as loss of station power or circulating water system failure.

DES indicated in its response to Federal Land Managers' June 26, 2009 Comments on NH's draft final Regional Haze SIP, that the wet FGD is currently being optimized for mercury emission reductions required by state law and that it is unreasonable to require state-of-the-art performance for SO2 removal as if it were the only pollutant of interest.

The temporary permit (TP-0008) for installation of the FGD required a minimum of 90 percent SO2 reduction. The permit also included provisions to reset the required SO2 percent reduction to the maximum sustainable rate after an initial operating period.

On September 1, 2016, DES issued Temporary Permit TP-0189 which established the maximum sustainable rate of SO2 reduction from the FGD. The rate was established based on a comprehensive review of actual FGD performance data. TP-0189 also established additional SO2 emission rates to ensure compliance with the 2010 1-hour SO2 NAAQS. These emission limitations established in TP-0189 represent the maximum performance of the state-of-the-art FGD system and compliance with strict federal

standards for SO2. Therefore, year-round use of the FGD is considered the most-effective use of controls for SO2 on Units 1 and 2.

C. Particulate Matter Control Strategies

DES has requested that GSP evaluate the most effective use of the current particulate matter (PM) control strategies for Unit 1 and to perform a four-factor analysis for reasonable installation or upgrade to emission controls for Unit 2.

vi. Units 1 and 2

Units 1 and 2 are each equipped with two electrostatic precipitators in series for the control of PM. Both the original and supplemental electrostatic precipitators are operated year-round in accordance with permit conditions to control PM emissions. The Title V permit (TV-0053) requires a minimum number of ESP sections in service during startup and normal operation of both Units 1 and 2. It is suspected that the wet FGD provides additional PM control, though PM reductions from the FGD have not been quantified.

Units 1 and 2 are subject to a BART emission control strategy established in Env-A 2300 for Mitigation of Regional Haze. EPA's June 26, 2009 Comments on NH's draft final Regional Haze SIP indicated that it is reasonable to consider the use of two currently installed ESPs as BART for Unit 2. EPA also indicated that the MANE-VU recommended level of BART control for non-CAIR EGUs is 0.02-0.04 lb/MMBtu. In response, DES established by rule a sustainable performance level of 0.08 lb/MMBtu for TSP emissions for both Unit 1 and Unit 2 even though Unit 1 was not a BART-eligible unit. By including Unit 1 in the rule, DES reduced allowable combined TSP emissions from the two coal-fired units at Merrimack Station to less than the total emissions that would be allowed if Unit 2 were set at the MANE-VU recommended level of 0.04 lb/MMBtu and the Unit 1 emission limit was unchanged.

DES indicated in its response to Federal Land Managers' June 26, 2009 Comments on NH's draft final Regional Haze SIP, that "the existing ESPs were previously upgraded to include state-of-the-art electronic controls and that further upgrading would require either major equipment substitutions or the addition of a third ESP in series with the two existing units. Adding a third ESP might be physically impossible because of sever spatial limitations following past improvements to emission control systems. To undertake either major equipment replacement or installation of a third ESP, if it could be done at all, would require a major capital expenditure. Typical equipment replacement costs for ESP upgrades may be in the range of $10,000 to $30,000 per MW. For Unit 2, additional costs of this

magnitude are not easily justified when weighed against the visibility improvement (less than 0.01 dv on the 20 percent worst visibility days) that would be realized."

Subsequent to establishing BART emission limits for TSP in Env-A 2300, Units 1 and 2 became subject to a MATS PM emission limit of 0.03 lb/MMBtu, which is even less than the MANE-VU recommendation for BART-eligible sources. GSP performed 3 years of quarterly stack testing for PM as required by the rule in order to achieve Low Emitting EGU (LEE) status. LEE status is achieved after 3 consecutive years of required quarterly tests are performed with resulting emissions less than 50 percent of the allowable emission rate of 0.03 lb/MMBtu. Units 1 and 2 have completed all quarterly testing required to demonstrate LEE status and are now subject to reduced stack testing frequency.

The current control strategy is considered the most-effective use of controls for PM emissions, given the year-round operation of ESPs on Units 1 and 2 and the magnitude of emissions (consistently less than 50 percent of the stringent federal 0.03 lb/MMBtu MATS limit).

V. Newington Station

Newington Station is a fossil fuel-fired electricity generating facility owned and operated by GSP Newington LLC, a wholly owned subsidiary of Granite Shore Power. The facility is comprised of one oil- and natural gas-fired EGU designated as Unit 1.

A. NOx Control Strategies

DES has requested that GSP evaluate the most effective use of the current NOx control strategies for Unit 1.

i. Unit 1

Newington Station already reduces its NOx emissions with combustion control technologies. Unit 1 is equipped with low NOx burners for oil combustion and an overfire air system for use during oil and natural gas combustion. These controls are used year-round in accordance with manufacturers recommendations. The overfire air system is separately optimized for oil and gas operation to meet daily NOx RACT limits of 0.35 lb/MMBtu for oil combustion and 0.25 lb/MMBtu for oil and gas combustion.

Unit 1 is subject to MATS as an existing EGU. Based on historical operating data, Unit 1 qualifies as a "limited-use liquid oil-fired EGU". Limited-use units are subject to tune-up requirements only. In the event that the annual capacity factor when burning oil exceeds 8

percent as averaged on a 24-month block period, Unit 1 would no longer qualify as a limited-use EGU, and instead be considered a "continental liquid oil-fired EGU" subject to emission limits. DES has included in Newington Station's Title V Permit (TV-0054) a requirement to conduct a NOx RACT analysis pursuant to Env-A 1315 within six months of submitting the notification of a MATS subcategory switch. At such time, Newington Station would evaluate technical and economic feasibility of additional NOx controls.

DES indicated in its response to EPA's June 26, 2009 comments on NH's draft final Regional Haze SIP Revision that the MANE-VU BART Workgroup draft presumptive control levels found in Appendix C of NESCAUM's "Five-Factor Analysis of BART Eligible Sources: Survey of Options for Conducting BART Determinations" are generally applicable to BART facilities having greater than 750 MW capacity and may not be representative of smaller EGUs like Newington Station Unit 1. DES also indicated that the workgroup's draft recommendations for EGUs do not take into account the effects of scale when a facility operates at very low utilization rates and capacity factors. DES went on to specifically state that the capital costs associated with SCR or SNCR to achieve a control level of 0.1 to 0.25 lb/MMBtu cannot be justified for Unit 1, especially on a visibility benefit basis. DES ultimately found that the existing NOx RACT limits reasonably represent the sustainable performance capabilities of this unit and are sufficient as BART control levels for NOX on a 30-day averaging basis.

VI. White Lake Station

The White Lake Combustion Turbine is located in the town of Tamworth, New Hampshire. White Lake serves primarily as a peaking unit, operating during the periods of highest seasonal peak demand. Additionally, this unit is called upon when a quick response is needed for additional generation to maintain electrical system stability.

A. NOx Control Strategies

DES has requested that GSP perform a four-factor analysis for reasonable installation or upgrade to NOx emission controls for the combustion turbine (WLCT).

i. WLCT

A four-factor analysis for reasonable installation or upgrade to NOx emission controls was performed for WLCT. The analysis is included as Attachment B. The analysis indicated that there were no technologically and economically feasible control options available for the combustion turbine. Alternatively, GSP will continue to look for opportunities to employ good combustion practices, such as the recently upgraded control system with

improved fuel control valve and routine inspections in accordance with manufacturer recommendations.

VII. Lost Nation Station

The Lost Nation Combustion Turbine is located in the town of Northumberland, New Hampshire. Lost Nation serves primarily as a peaking unit, operating during the periods of highest seasonal peak demand. Additionally, this unit is called upon when a quick response is needed for additional generation to maintain electrical system stability.

A. NOx Control Strategies

DES has requested that GSP perform a four-factor analysis for reasonable installation or upgrade to NOx emission controls for the combustion turbine (LNCT).

i. LNCT

A four-factor analysis for reasonable installation or upgrade to NOx emission controls was performed for LNCT. The analysis is included as Attachment B. The analysis indicated that there were no technologically and economically feasible control options available for the combustion turbine. Alternatively, GSP will continue to look for opportunities to employ good combustion practices, such as the recently upgraded control system with improved fuel control valve and routine inspections in accordance with manufacturer recommendations.

VIII. Conclusion

GSP appreciates the opportunity to provide this discussion to inform DES' response to the MANE-VU "Ask" and support its reasonable progress goals for regional haze. As explained above, GSP already operates its existing control technologies in the most effective manner to reduce emissions as required by stringent federal emission standards. Separately, a four-factor analysis for the addition of NOx controls on the combustion turbines revealed that only SCR technology is technically feasible, however SCRs are not economically feasible given the high installation and maintenance costs for units with limited opportunity for NOx reduction.

If you have any questions regarding this submittal please contact Melissa A. Cole, P.E., Environmental Engineer at 603-230-7917 or Melissa.Cole@graniteshorepower.com.

Sincerely,

GRANITE SHORE POWER

Elizabeth H. Tillotson

Elizabeth H. Tillotson
Executive Director of Administration & Regulatory Affairs

ATTACHMENT A

RACT/BACT/LAER CLEARINGHOUSE DATABASE REVIEW

Granite Shore Power
183-110
EPA Database Review[1]

Facility	NOX Control	Primary Fuel(s)	Unit Rating	Units	First Emissions Limit			Second Emissions Limit			Conversion to lb/MMBtu	
BOISE WHITE PAPER	LOW NOX BURNERS	WOOD	435	MMBtu/hr	0.3	LB/MMBTU	3 H	130.5	LB/H	3 H	0.3	lb/MMBtu
DEL TIN FIBER LLC	LOW NOX COMBUSTORS AND SNCR	WOOD WASTE	291	MMBtu/hr	87.2	LB/H		386.1	T/YR		0.3	lb/MMBtu
SIERRA PACIFIC INDUSTRIES-LOYALTON	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	WOOD	335.7	MMBtu/hr	102	PPM	@12% CO2, 8-HR ROLLING AVG	65	LB/H	8-HR ROLLING AVG	0.19	lb/MMBtu
SIERRA PACIFIC INDUSTRIES-LOYALTON	SELECTIVE NON-CATALYTIC REDUCTION (SNCR)	WOOD	335.7	MMBtu/hr	80	PPM	@12% CO2, 8-HR ROLLING AVG	50.75	LB/H	8-HR ROLLING AVG	0.15	lb/MMBtu
PLAINFIELD RENEWABLE ENERGY, LLC	SNCR	Wood	523.1	MMBtu/hr	0.075	LB/MMBTU		45.3	PPMVD @7% O2	24 HR BLOCK	0.075	lb/MMBtu
WHEELABRATOR SHERMAN ENERGY COMPANY	GOOD COMBUSTION PRACTICES	WOOD	315	MMBtu/hr	0.25	LB/MMBTU	30 day avg	345.8	T/YR		0.25	lb/MMBtu
DISTRICT ENERGY ST. PAUL, INC	SELECTIVE, NON-CATALYTIC REDUCTION, SNCR	WOOD	550	MMBtu/hr	0.15	LB/MMBTU		0.11	LB/MMBTU, GAS		0.15	lb/MMBtu
SOUTH POINT BIOMASS GENERATION	SELECTIVE CATALYTIC REDUCTION	WOOD	318	MMBtu/hr	27.98	LB/H		122.55	T/YR	PER ROLLING 12 MONTHS	0.09	lb/MMBtu
GP ALLENDALE LP	NOX EMISSIONS CONTROLLED THROUGH A COMBINATION OF STAGED COMBUSTION AND FLUE GAS RECIRCULATION.	WOOD	334	MMBtu/hr	119.28	LB/H		408.95	T/YR		0.36	lb/MMBtu
GP ALLENDALE LP	NOX EMISSIONS CONTROLLED THROUGH A COMBINATION OF STAGED COMBUSTION AND FLUE GAS RECIRCULATION.	WOOD	334	MMBtu/hr	119.28	LB/H		408.95	T/YR		0.36	lb/MMBtu
GP ALLENDALE LP	NOX EMISSIONS CONTROLLED THROUGH A COMBINATION OF STAGED COMBUSTION AND FLUE GAS RECIRCULATION.	WOOD	197	MMBtu/hr	119.28	LB/H		408.95	T/YR		0.61	lb/MMBtu
GP CLARENDON LP	NOX EMISSIONS CONTROLLED THROUGH A COMBINATION OF STAGED COMBUSTION AND FLUE GAS RECIRCULATION.	WOOD	334	MMBtu/hr	119.28	LB/H		408.95	T/YR		0.36	lb/MMBtu
GP CLARENDON LP	NOX EMISSIONS CONTROLLED THROUGH A COMBINATION OF STAGED COMBUSTION AND FLUE GAS RECIRCULATION.	WOOD	197	MMBtu/hr	119.28	LB/H		408.95	T/YR		0.61	lb/MMBtu
GP CLARENDON LP	NOX EMISSIONS CONTROLLED THROUGH A COMBINATION OF STAGED COMBUSTION AND FLUE GAS RECIRCULATION.	WOOD	334	MMBtu/hr	119.28	LB/H		408.95	T/YR		0.36	lb/MMBtu
LUFKIN GENERATING PLANT	Selective Catalytic Reduction	wood	693	MMBtu/hr	0.075	LB/MMBTU	ROLLING 30-DAY AVERAGE	0			0.075	lb/MMBtu
DARRINGTON ENERGY COGENERATION POWER PLANT	SNCR	WOOD WASTE	403	MMBtu/hr	0.12	LB/MMBTU	24-HR	0			0.12	lb/MMBtu
SIMPSON TACOMA KRAFT COMPANY, LLC	PROPER COMBUSTION CONTROLS WITH OVERFIRE AIR	WOOD WASTE	595	MMBtu/hr	0.2	LB/MMBTU	30 DAY ROLLING AVERAGE	522	T	12 MONTH ROLLING	0.2	lb/MMBtu
BOISE WHITE PAPER LLC	OVERFIRE AIR SYSTEM ADDED TO IMPROVE BOILER COMBUSTION SYSTEM. BOILER HAS AN ESP.	WOOD/BARK	343	MMBtu/hr	0.3	LB/MMBTU	30 DAY ROLLING	0			0.3	lb/MMBtu
RIPLEY HEATING PLANT	SELECTIVE NON-CATALYTIC REDUCTION (SNCR) FOR OXIDES OF NITROGEN	WOOD & COAL	185	MMBTU/H	0.1	LB/MMBTU		89.8	T/YR		0.1	LB/MMBTU

1 - Technology Transfer Network, Clean Air Technology Center, RACT/BACT/LAER Clearinghouse database review - Utility and Large Industrial-Size (>250 MMBtu/hr) and Industry Boilers (>100 MMBtu/hr) firing biomass, dated August 27, 2018

Identified as CFBs

Wood boiler w/SCR control

ATTACHMENT B

FOUR-FACTOR ANALYSIS FOR REASONABLE INSTALLATION OR UPGRADE TO EMISSION CONTROLS

REASONABLE PROGRESS REPORT

WHITE LAKE GENERATING STATION – TAMWORTH, NEW HAMPSHIRE
LOST NATION GENERATION STATION – NORTHUMBERLAND, NEW HAMPSHIRE
MERRIMACK STATION – BOW, NES HAMPSHIRE
SCHILLER STATION – PORTSMOUTH, NEW HAMPSHIRE

PREPARED FOR:

GRANITE SHORE POWER LLC

PREPARED BY:

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CEC PROJECT 183-110

AUGUST 2018

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Appendix A Summary of NO_X Control Technologies

Appendix B SCR Cost Effectiveness at 73 Hours Per Year

1.0 INTRODUCTION

Granite Shore Power LLC ("GSP") submits the following in response to the Mid-Atlantic/Northeast Visibility Union's (MANE-VU) *Statement of MANE-VU States Concerning a Course of Action Within MANE-VU Toward Assuring Reasonable Progress For the Second Regional Haze Implementation Period (2018-2028)*, dated August 25, 2017. As the owner and operator of four generating stations with five peaking combustion turbines in New Hampshire: White Lake Generating Station, Lost Nation Generating Station, Merrimack Station, and Schiller Station; GSP appreciates the opportunity to be involved in the response to MANE-VU.

Based on the results of the analyses for reasonable installation or upgrade to emissions controls conducted, GSP anticipates that the current requirements and nitrogen oxide (NO_X) emissions levels will be retained for each of the five peaking combustion turbines.

2.0 BACKGROUND

In accordance with the MANE-VU statement:

> The federal Clean Air Act (CAA) and Regional Haze rule requires States that are reasonably anticipated to cause or contribute to impairment of visibility in mandatory Class I Federal areas to implement reasonable measures to reduce visibility impairment within the national parks and wilderness areas designated as mandatory Class I Federal areas.

Furthermore:

> According to the Regional Haze rule (40 CFR 51.308 (f)(2)(i) through (iv)), all states must consider, in their Regional Haze SIPs, the emission reduction measures identified by Class I States as being necessary to make reasonable progress in any Class I area. These emission reduction measures are referred to as "Asks." If any State cannot agree with or complete a Class I State's "Ask," the State must describe the action taken to resolve the disagreement in their Regional Haze SIP…
>
> To address the impact on mandatory Class I Federal areas within the MANE-VU region, the Mid-Atlantic and Northeast State will pursue a coordinated course of action designated to assume reasonable progress toward preventing any future, and remedying any existing impairment of visibility in mandatory Class I Federal areas and to leverage the multi-pollutant benefits that such measure may provide for the protection of public health and the environment…

SIPs are to be submitted between July 2018 and July 2021. With the objective of meeting the 2028 reasonable progress goal for regional haze, five different "emission management" strategies were developed. Strategy 5 applies to the five peaking combustion turbines operated by GSP.

5. Where emission rules have not been adopted, control NO_X emissions for peaking combustion turbines that have the potential to operate on high electric demand days by:

    a. Striving to meet NO_X emission standard of no greater than 25 ppm at 15% O_2 for natural gas and 42 ppm at 15% O_2 for fuel oil but at a minimum meet NO_X emissions standard of no greater than 42 ppm at 15% O_2 for natural gas and 96 ppm at 15% O_2 for fuel oil, or

    b. Performing a four-factor analysis for reasonable installation or upgrade to emission controls, or

    c. Obtaining equivalent alternative emission reductions on high electric demand days.

3.0 DESCRIPTION OF GENERATING STATIONS

GSP owns and operates five peaking combustion turbines at their four generating stations in New Hampshire that are associated with this Ask. The combustion turbines are all classified as small turbines (<25 megawatts, MW) and given their vintage (1968-1970), there are no existing NO_X controls other than good combustion practices.

3.1 WHITE LAKE GENERATING STATION

The White Lake Generating Station is located in Tamworth, New Hampshire, and is operated under State-Only Operating Permit No. SP-0216. Emission Unit EU01 is a Pratt & Whitney simple-cycle combustion turbine, installed in 1968. Its maximum heat input is 300 million British Thermal Units per hour (MMBtu/hr), which is equivalent to 2,222 gallons per hour (gal/hr), based on a heating value of 135,000 Btu/gal of kerosene-1 fuel. Fuel consumption is permit-limited to 908,270 gallons of kerosene in any consecutive 12-month period and emissions are subject to a facility-wide emissions limit of 50 tons per year (tpy) of NO_X. Based on stack testing conducted in 2015, the average NO_X emission rate for EU01 is 0.642 lb/MMBtu.

3.2 LOST NATION GENERATING STATION

The Lost Nation Generating Station is located in Northumberland, New Hampshire, and is operated under State-Only Operating Permit No. SP-0217. Emission Unit EU01 is a General Electric simple-cycle combustion turbine, installed in 1969. Its maximum heat input is 315 MMBtu, which is equivalent to 2,250 gal/hr, based on a heating value of 140,000 British Thermal units per gallon (Btu/gal) of #2 fuel oil. Fuel consumption is permit-limited to 981,100 gallons of No. 2 fuel oil in any consecutive 12-month period and emissions are subject to a facility-wide emissions limit of 50 tpy of NO_X. Lost Nation is also permitted to operate a starter engine with 4 MMBtu/hr rated heat input. Based on stack testing conducted in 2015, the average NO_X emission rate for EU01 is 0.641 lb/MMBtu.

3.3 MERRIMACK STATION

The Merrimack Station is located in Bow, New Hampshire, and is operated under Title V Operating Permit No. TV-0055. Emission Units MKCT1 and MKCT2 are both Pratt & Whitney simple-cycle combustion turbines, installed in 1968 and 1969, respectively. Each combustion turbine has a maximum fuel consumption permit limit of 2,279 gal/hr (19.96 million gallons during any 12-month consecutive period) based on a fuel heating value of 140,000 Btu/gal. The combustion turbines can fire either No. 1 fuel oil or jet fuel (JP-4). The combustion turbines are subject to a NO_X limit of 0.09 pounds per million British Thermal unit (lb/MMBtu) on an hourly average, which is the existing Reasonably Available Control Technology (RACT) limit. Based on stack testing conducted in 2016, the average NO_X emission rate for MKCT1 is 0.827 lb/MMBtu and MKCT2 is 0.857 lb/MMBtu.

Merrimack is also permitted to operate two steam generating units, a primary coal crusher, a secondary coal crusher, an emergency generator, an emergency boiler, and an emergency cooling pump.

3.4 SCHILLER STATION

The Schiller Station is located in Portsmouth, New Hampshire, and is operated under Title V Operating Permit No. TV-0053. Emission Unit SRCT is a Pratt & Whitney simple-cycle combustion turbine, installed in 1970. Its maximum heat input is 290 MMBtu, which is equivalent to 2,070 gal/hr of distillate fuel (#2 fuel oil, JP-4, kerosene) or 290,000 cubic feet per hour (cf/hr) of natural gas. Fuel oil consumption is limited to 13,900,000 gallons in any consecutive 12-month period. The fuel consumption rates are based on the following assumed heating values: 12,700 Btu/lb (bituminous coal), 150,000 Btu/gal (No. 6 fuel oil), 140,000 Btu/gal (distillate oil), 4,275 Btu/lb (wood), 1,000 Btu/ft^3 (natural gas), and 94,000 Btu/gal (propane). The combustion turbine is subject to a NO_X limit of 0.09 lb/MMBtu on an hourly average, which is the existing RACT limit. Based on stack testing conducted in 2016, the average NO_X emission rate for SRCT is 0.8 lb/MMBtu.

Schiller is also permitted to operate two steam generating units, a fluidized bed boiler, a primary coal crusher, a secondary coal crusher, an emergency generator, and a heating system boiler.

4.0 REASONABLE PROGRESS EVALUATION PROCESS

The reasonable progress evaluation requested for the five peaking combustion turbines is an assessment of the applicable control technologies capable of reducing emissions of a pollutant and is conducted using a “top-down” approach taking into account feasibility and cost effectiveness, as well as, economic, environmental, and energy impacts. These assessments are conducted on a case-by-case basis using site-specific information, as available. The result of the analysis may not result in emissions of a pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Part 60 or 61.

The reasonable progress evaluation generally follows U.S. EPA-developed guidance for Best Available Control Technology (BACT) as outlined in Chapters B and G of the U.S. EPA Draft *New Source Review Workshop Manual* (OAQPS, October 1990). The five-step process includes:

Step 1: Identify Available Control Technologies;

Step 2: Eliminate Technically Infeasible Options;

Step 3: Rank Remaining Control Technologies by Control Effectiveness;

Step 4: Evaluate Economic, Environmental, and Energy Impacts of Technically Feasible Control Technologies; and

Step 5: Select BACT.

However, the reasonable progress evaluation essentially combines steps 4 and 5 into one – "Evaluate Factors and Present Determination." The four factors to be evaluated are: the cost of compliance, the time necessary for compliance, energy and non-air quality impacts, and the remaining useful life. The reasonable progress evaluation also incorporates guidance provided by the New Hampshire Department of Environmental Services (DES).

4.1 STEP 1 – IDENTIFY AVAILABLE CONTROL TECHNOLOGIES

The first step in the reasonable progress evaluation analysis is to identify "available" control options. Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and pollutant under evaluation, with a focus on technologies that have been demonstrated to achieve the highest levels of control for the pollutant in question, regardless of the source type in which the demonstration has occurred.

4.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

In the second step of the reasonable progress evaluation, any available control technique listed in Step 1 may be eliminated from further consideration if it is not technically feasible for the specific source under review. A demonstration of technical infeasibility must be documented and show, based on physical, chemical, or engineering principles, that technical difficulty would preclude the successful use of the control option on the emissions unit under review. U.S. EPA generally considers a technology to be technically feasible if it has been demonstrated and operated successfully on the same type of emissions unit under review or is available and applicable to the emissions unit type under review. If a technology has been operated on the same type of emissions unit, it is presumed to be technically feasible. An available technology from Step 1, however, cannot be eliminated as infeasible simply because it has not been used on the same type of source that is under review. If the technology has not been operated successfully on the type of source under review, then questions regarding "availability" and "applicability" to the particular source type under review should be considered for the technology to be eliminated as technically infeasible.

4.3 STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

Step 3 of the reasonable progress evaluation calls for the remaining control technologies to be listed in order of overall control effectiveness for the pollutant under review. The most effective control alternative (i.e., the option that achieves the lowest emissions level) should be listed at the top and the remaining technologies ranked in descending order of control effectiveness. The ranking of control options in Step 3 determines where to start the "top-down" selection process in Step 4. In determining and ranking technologies based on control effectiveness, facilities should include information on each technology's control efficiency (e.g., percent pollutant removed, emissions per unit product), expected emission rate (e.g., tpy, pounds per hour [lb/hr], pounds per unit of product, pounds per unit of input, parts per million [ppm]), and expected emissions reduction (e.g., tpy). The metrics chosen for ranking should best represent the array of control technology alternatives under consideration.

4.4 STEP 4 – EVALUATE FACTORS AND PRESENT DETERMINATION

Under Step 4 of the reasonable progress evaluation, facilities must consider the cost of compliance, time necessary for compliance, energy and non-air quality impacts, and remaining useful life of each option remaining options under consideration. Accordingly, after available and technically feasible control options have been ranked in terms of control effectiveness (Step 3), facilities should consider these four factors when presenting the determination for reasonable installation or upgrade of emission controls. If the most stringent control option (based on the ranking of controls under Step 3) is eliminated from further consideration for reasonable installation, then the next most stringent alternative is considered, and so on, until a final determination of all controls is completed.

5.0 REASONABLE PROGRESS EVALUATION FOR NO_X

NO_X is primarily formed by two mechanisms: the combination of elemental nitrogen and O_2 in the combustion air within the high temperature environment of the combustor (thermal NO_X) and the oxidation of nitrogen contained in the fuel (fuel NO_X). NO_X emissions from combustion turbines when firing fuel originate primarily as thermal NO_X. The rate of formation of thermal NO_X is a function of residence time and free oxygen, and is exponential with peak flame temperature. Fuel oil has a higher flame temperature and produces more NO_X than natural gas.

5.1 STEP 1 - IDENTIFY AVAILABLE CONTROL TECHNOLOGIES

The scope of potentially applicable control options was determined based on a review of the U.S. EPA RACT/BACT/LAER Clearinghouse (RBLC) database for entries within the last 10 years for simple-cycle combustion turbines, as well as other publically available information such as the Air Pollution Training Institute[1] or other recently permitted combustion turbines. RBLC entries that were not representative of the emissions unit, proposed fuel, or operating condition were excluded

[1] https://www.apti-learn.net/lms/register/display_document.aspx?dID=39

from further consideration. In addition, entries that were proven to not meet an emissions limit were also excluded from further consideration. A summary table is presented in Appendix A. Given there are essentially two ways to reduce NO_X emissions—primary (or in-combustor) methods that minimize the production of NO_X in the turbine and secondary methods (or add-on controls) that reduce the NO_X that has been formed—controls have been identified as such. In addition, while not a technology per se, use of good combustion practices is a common baseline approach to optimizing the emissions profile for combustion turbines so it has been included here as well.

5.1.1 Primary Controls - Water or Steam Injection

Water or steam injection is an example of an "in-combustor" NO_X control technology. The addition of an inert diluent, such as water or steam, into the high temperature region of the combustion turbine flame controls NO_X formation by quenching peak flame temperatures.

5.1.2 Primary Controls - Dry Low-NO_X/Dry Low-Emission (DLN/DLE) Combustors

DLN/DLE combustors are also an example of an "in-combustor" NO_X control technology. The combustors limit peak flame temperature and excess oxygen with lean, pre-mix flames that achieve NO_X control equal to or better than water or steam injection. Each combustion turbine vendor has their own version of this technology—Siemens (ULN), General Electric (DNL 2.6+), Pratt & Whitney (TALON X, previously known as rich burn quick mix, lean burn (RQL) [2]), etc. These combustors are generally built into the original design of the combustion turbine, but can be retrofitted for certain models.

5.1.3 Secondary Controls - XONON™ Catalytic Combustor

The XONON™ catalytic combustor system is a NO^X control technology developed by Catalytica Energy Systems, Inc. It works by avoiding high temperatures caused by combustion. By integrating a catalyst into the combustor, XONON™ limits combustion temperatures to below the level where NO_X is formed. The XONON™ catalytic combustor system is a module that is installed inside the main component of the combustor. The module consists of a channel where pre-mixed fuel and air passes through the catalyst. It eliminates the fuel being combusted in a flame by combusting it using a catalyst at a lower temperature. Thus, NO_X formation is reduced. The XONON™ catalytic combustor system is now owned by Kawasaki Heavy Industries, Ltd. which is in the process of making the control technology available for gas turbine generators in the 1-1.4 MW range.

5.1.4 Secondary Controls - SCONOX™ Process (aka EMx™)

The SCONOX™ process is a NO_X control technology developed by Goal Line Environmental Technologies (GLET). It uses a coated oxidation catalyst to oxidize and remove NO_X (as well as carbon monoxide, CO) without using a reagent such as NH_3 or NH_3(aq). The technology is now

[2] https://www.researchgate.net/publication/266595753_Rich_Burn_Quick-_Mix_Lean_Burn_RQL_Combustor

on its second generation, called EMx™, and is distributed by EmeraChem (formerly GLET). The technology is made of a platinum-based catalyst coated with potassium carbonate (K_2CO_3) and works by oxidizing CO to carbon dioxide (CO_2) and nitrogen oxide (NO) to nitrogen dioxide (NO_2). The CO_2 is then exhausted from the system and the NO_2 absorbs onto the K_2CO_3 catalyst to form potassium nitrite (KNO_2) and potassium nitrate (KNO_3). The K_2CO_3 is regenerated by running hydrogen gas (H_2) across the catalyst. Consistent operations can be maintained using four out of five catalyst modules in a rotating fashion while the fifth module is regenerated.

A pitfall of the control technology is its potential to deactivate when exposed to sulfur oxides (SO_X). In order to prevent this issue, an additional catalytic oxidation/absorption system known as SCOSOX™ is installed upstream of the SCONOX™ catalyst to first oxidize sulfur dioxide (SO_2) to sulfur trioxide (SO_3). Also, both the SCONOX™ and SCOSOX™ catalysts are required to be washed every six to 12 months, which involves removing the catalysts from the modules. Using a fuel with low sulfur content decreases the frequency of washes required.

5.1.5 Secondary Controls - Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a control technology used to convert NO_X into diatomic nitrogen (N_2) and water (H_2O) using a catalyst. The reduction reactions used by SCR require oxygen, so it is most effective at oxygen levels above 2-3%. Base metals such as vanadium or titanium are often used for the catalyst due to their effectiveness as a control technology for NO_X and cost-effectiveness for use with natural gas combustion. In addition, a gaseous reductant such as anhydrous ammonia (NH_3) or aqueous ammonia (NH_3(aq)) is added to the flue gas and absorbed onto the catalyst. The optimal temperature range for most SCT catalyst range from 600 degrees Fahrenheit (°F) to 800°F.

5.1.6 Secondary Controls - Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is a post-combustion control technology for NO_X emissions that uses a reduction-oxidation reaction to convert NO_X into nitrogen (N_2), water (H_2O), and carbon dioxide (CO_2). Like SCR, SNCR involves injecting ammonia (or urea) into the flue gas stream, which must be between approximately 1,400 and 2,000°F for the chemical reaction to occur. SNCR is more economically desirable due to the lack of catalyst required and, in theory, SNCR can control NO_X emissions with an efficiency similar to that of SCR (i.e., 90%). However, operating constraints on temperature, reaction time, and mixing often lead to less effective results when using SNCR in practice.

5.1.7 Alternative Controls - Good Combustion Practices

Good combustion practices are a method of controlling NO_X emissions from a combustion turbine. Maintaining optimum combustion efficiency or implementing appropriate maintenance procedures are examples of good combustion practices.

5.2 STEP 2 - ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

5.2.1 Primary Controls

GSP contacted Turner EnviroLogic, Inc.[3], a reputable provider of air pollution control equipment and systems for industrial and power generation businesses. It is their opinion that only the original manufacturer would be in the position to retrofit combustion turbines of this vintage with primary controls. GSP then contacted Pratt & Whitney (P&W) engineering to discuss the potential for retrofitting this vintage (1968-1970) combustion turbine with their low emissions combustor, TALON X (formerly known as Rich-Quench Lean (RQL) combustion. P&W said that they no longer support these model combustion turbines. GSP also contacted General Electric (GE) engineering to discuss the potential to retrofit a 1969 model combustion turbine with their DLN 2.6+ technology, but as of the date of this report, there has not been a response. However, research conducted on-line regarding DLN 2.6+ indicates that it is only available for newer model combustion engines. Based on the on-line research and discussions with P&W, it has been determined that retrofitting with primary controls should not be considered technically feasible for these combustion turbines. Therefore, water or steam injection and DLN/DLE combustors have been eliminated from further analysis.

5.2.2 Secondary Controls - XONON™ Catalytic Combustor

Although developments to the XONON™ control technology are underway for gas turbines, such that it may become effective in gas turbine generators in the 1-1.4 MW range, this technology has not yet become available for application to larger turbine units. The current XONON™ catalytic combustor system has not been used on larger (i.e., greater than 1.4 MW) combined-cycle turbines and therefore, it is not considered technically feasible.

5.2.3 Secondary Controls - SCONOX™ Process (aka EMx™)

Although there have been developments to the SCONOX™ control technology, the current process has not been used on larger (i.e., greater than 1.4 MW) combustion turbines and therefore, it is not considered technically feasible.

5.2.4 Secondary Controls - Selective Catalytic Reduction

SCR has been used historically on combustion turbines and is considered technically feasible, and therefore is considered further in the evaluation.

5.2.5 Secondary Controls - Selective Non-Catalytic Reduction

SNCR is considered technically infeasible for the proposed combustion turbines due to the temperature at which the turbines will operate, the residence time of the technology, and the lack of historical use of SNCR on combustion turbines. Therefore, SNCR is not considered technically feasible.

[3] http://tenviro.com/

5.2.6 Alternative Controls - Good Combustion Practices

Good combustion practices are considered technically feasible, and therefore are considered further in the evaluation.

5.3 STEP 3 - RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

Control Type	Control Efficiency	Ranking
SCR	90%	1
Good Combustion Practices	10%	2

5.4 STEP 4 - EVALUATE FACTORS AND PRESENT DETERMINATION

Good combustion practices are already being employed by GSP for each of the combustion turbines; consequently, no cost of compliance analysis was conducted for this type of control. Therefore, presented below is the four-factor analysis (cost of compliance) for SCR.

5.4.1 Factor 1: Cost of Compliance

The cost of compliance, measured in terms of annual control costs (dollars) per air emissions reduced (tons), was calculated according to the U.S. EPA Air Pollution Control Cost Manual, sixth edition. The capital cost was provided by an air pollution control vendor (Turner EnviroLogic[4]) and annualized using a capital recovery factor. The annual operating and maintenance costs were estimated using EPA default values and site-specific data, as available. These two costs were then summed and divided by the tons of pollutant anticipated to be removed.

GSP's five combustion turbines are of the same vintage (installed 1968-1970), have similar unit ratings (290 MMBtu/hr - 319 MMBtu/hr), are operated in the similar manner (operate less 1% of the number of hours in a given year), and have similar NO_X emissions (ranging from 0.7 lb/MMBtu to 0.9lb/MMBtu). Therefore, a representative cost of compliance analysis was conducted for the unit at Schiller Station.

Since the combustion turbines are peaking units, the annual capacity factor is typically less than 1%. In fact, when GSP conducted a lookback of combustion turbine operation over the last ten years at Schiller Station, it was found that the year with highest hours of operations was 2010. In 2010, the combustion turbine operated a total of 73 hours, which equated to 3.4 tons of NO_X emissions for the year. Accordingly, the representative cost of compliance analysis was conservatively based on data from 2010. Results indicate that the average cost of compliance (dollar per ton reduced) would be in excess of $197,000 (see Table 1 below). The detailed cost of compliance is provides in Appendix B.

[4] http://tenviro.com/

Table 1. Cost of Compliance – Schiller Station Combustion Turbine

Control Type	NO_X Potential Emissions (tpy)	NO_X Reduced via Controls (tpy)[(a)]	Total Annualized Cost ($)	Average Cost of Compliance ($/ton reduced)
SCR @ 73 hours	3.4	3.1	604,428	197,525

(a) Assumes 90% control.

5.4.2 Factor 2: Time Necessary for Compliance

The minimal time necessary to install an SCR would be approximately 6 months.

5.4.3 Factor 3: Energy and Non-Air Quality Impacts

SCR catalysts must be disposed of properly. If not, non-air quality impacts could be realized. In addition, concerns related to the transportation, storage and use of ammonia should be considered as non-air quality impacts.

5.4.4 Factor 4: Remaining Useful Life

Based on the PSNH Generation Asset and PPA Valuation Report prepared for the New Hampshire Public Utilities Commission[5], dated March 31, 2014, the remaining useful life of each of the combustion turbines is 15 years. Please note this is a conservative assumption as the report stated a 15-year book life in March 2014.

6.0 CONCLUSION

GSP appreciates the opportunity to provide input in response to the MANE-VU Ask. As indicated by the results of the four-factor analysis for reasonable installation or upgrade to emission controls presented above, there are no additional NO_X controls that GSP could employ on the combustion turbines that are both technically and economically feasible. GSP already employs good combustion practices to optimize their NO_X emissions profile. Therefore, the current requirements and NO_X emissions levels will be retained for each of the five peaking combustion turbines.

[5] http://www.puc.state.nh.us/Electric/PUBLIC%20VERSION%20PSNH%20Asset%20Valuation%20Report_FINAL.pdf

APPENDIX A
SUMMARY OF NO_X CONTROL TECHNOLOGIES

Appendix A
Summary of NOx Control Technologies as Reported in the RBLC Database
Granite Shore Power LLC
183-110

Natural Gas

Facility Name	Process Name	Fuel	Throughput	Units	Pollutant	Control(s)	Emission Limit	Units	Averging Period
KENAI NITROGEN OPERATIONS	Five (5) Natural Gas Fired Combustion Turbines	Natural Gas	37.6	MMBTU/H	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	7	PPMV	3-HR AVG @ 15 % O2
HILLABEE ENERGY CENTER	COMBUSTION TURBINE	Natural Gas	2142	MMBTU/H	Nitrogen Oxides (NOx)	LOW-NOX BURNER, SCR	24.6	LB/H	
STERLINGTON COMPRESSOR STATION	COMPRESSOR TURBINE NO. 1	Natural Gas	79.1	MMBTU/H	Nitrogen Oxides (NOx)	DRY LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	0.057	LB/MMBTU	
STERLINGTON COMPRESSOR STATION	COMPRESSOR TURBINE NO. 2	Natural Gas	79.1	MMBTU/H	Nitrogen Oxides (NOx)	DRY LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	0.057	LB/MMBTU	
THETFORD GENERATING STATION	FGCCA or FGCCB--4 nat. gas fired CTG w/ DB for HRSG	Natural Gas	2587	MMBTU/H	Nitrogen Oxides (NOx)	Low NOx burners and selective catalytic reduction.	3	PPMV	24-H ROLLING AVERAGE
THETFORD GENERATING STATION	FGCCA or FGCCB: 4 nat gas fired CTG with DB for HRSG: Startup/shutdown events	Natural Gas	2587	MMBTU/H	Nitrogen Oxides (NOx)	Low NOx burners and selective catalytic reduction.	78.4	T/YR	12-MO ROLL TIME PERIOD FOR STARTUP/SHUTD
DTE GAS COMPANY--MILFORD COMPRESSOR STATION	FG-TURBINES	Natural Gas	10504	HP	Nitrogen Oxides (NOx)	Dry ultra-low NOx burners	15	PPM	TEST PROTOCOL
DTE GAS COMPANY - MILFORD COMPRESSOR STATION	FGTURNBINES (5 Simple Cycle CTs: EUTURBINE1, EUTURBINE2, EUTURBINE3, EUTURBINE4, EUTURBINE5)	Natural Gas	10504	HP	Nitrogen Oxides (NOx)	Dry ultra-low NOx burners.	15	PPM	
MGM MIRAGE	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	Natural Gas	4.6	MMBTU/H	Nitrogen Oxides (NOx)	LEAN PRE-MIX TECHNOLOGY AND LIMITING THE FUEL TO NATURAL GAS ONLY	0.178	LB/MMBTU	
BUFFALO CREEK PROCESSING PLANT	Small Combustion Turbines (<25MW)	Natural Gas	10179	Horsepower	Nitrogen Oxides (NOx)	Dry-Low NOx Combustion	15	PPMVD@15%O2	1-HR
ROSE VALLEY PLANT	TURBINES 9,443-HP SIEMENS SGT-200-2S	Natural Gas	9443	HP	Nitrogen Oxides (NOx)	DRY LOW-NOx COMBUSTION.	15	PPMVD @15% O2	1-HR
GUADALUPE GENERATING STATION	(2) simple cycle turbines	Natural Gas	190	MW	Nitrogen Oxides (NOx)	DLN burners, limited operation	9	PPMVD	@15% O2, 3 HOUR ROLLING AVG
ECHO SPRINGS GAS PLANT	TURBINES S35-S36	Natural Gas	12555	HP	Nitrogen Oxides (NOx)	SOLONOX	15	PPMV	
ECHO SPRINGS GAS PLANT	TURBINE S37	Natural Gas	16162	HP	Nitrogen Oxides (NOx)	GOOD COMBUSTION PRACTICES	15	PPMV	
ECHO SPRINGS GAS PLANT	TURBINE S34	Natural Gas	3856	HP	Nitrogen Oxides (NOx)	SOLONOX	25	PPMV	

Fuel Oil

Facility Name	Process Name	Fuel	Throughput	Units	Pollutant	Control(s)	Emission Limit	Units	Averging Period
POINT THOMSON PRODUCTION FACILITY	Turbines	Fuel Gas	7520	kW	Nitrogen Oxides (NOx)	Dry Low NOx and SoLoNOx.	15	PPMV	15% OXYGEN

APPENDIX B
SCR COST EFFECTIVENESS AT 73 HOURS PER YEAR

Granite Shore Power - Schiller Station
Portsmouth, New Hampshire
Cost Effectiveness - Selective Catalytic Reduction - Combustion Turbine (SRCT)
73 hours per year
CEC Project #183-110

Prepared By: JLF | **Reviewed By:** JG
Date Prepared: 8/27/2018 | **Date Reviewed:** 8/28/2018

Item	Value	Basis[1]
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries[2] **[A]**	$2,000,000	**A**
Instrumentation	$200,000	0.10 x A
Freight	$160,000	0.08 x A
Total Purchased Equipment Cost **[B]**	**$2,360,000**	**B** = 1.18 x A
Direct Installation Costs		
Foundations and supports	$188,800	0.08 x B
Handling and erection	$330,400	0.14 x B
Electrical	$94,400	0.04 x B
Piping	$47,200	0.02 x B
Insulation for ductwork	$23,600	0.01 x B
Painting	$23,600	0.01 x B
Total Direct Installation Cost	**$708,000**	0.30 x B
Buildings (Bldg.)	**$118,000**	As required (5-18% B)
Total Direct Cost (DC)	**$3,186,000**	1.35 x B
Indirect Costs (Installation)		
Engineering	$236,000	0.10 x B
Construction and field expenses	$118,000	0.05 x B
Contractor fees	$236,000	0.10 x B
Start-up	$47,200	0.02 x B
Performance test	$23,600	0.01 x B
Contingencies	$70,800	0.03 x B
CEMs	$70,000	Assumption to purchase & install
		Assumption to prepare application & review draft
PSD Permit	$75,000	permit
Other	$0	As required
Construction period	0.5	Years
Interest Rate	7%	Percent
Interest during construction (Int.)	$111,510	DC * i *n
Total Indirect Cost (IC)	**$988,110**	0.31 x B + Int + PSD
Total Capital Investment (TCI) = DC + IC	**$4,174,110**	1.61 x B + Bldg. + Int. + CEMs + PSD

1 - EPA's OAQPS Cost Control Manual, Sixth Edition unless otherwise noted
2 - Estimate provided by Tom Turner, P.E. of Turner EnviroLogic, Inc., dated August 23, 2018.

Granite Shore Power - Schiller Station
Portsmouth, New Hampshire
Cost Effectiveness - Selective Catalytic Reduction - Combustion Turbine (SRCT)
73 hours per year
CEC Project #183-110

Prepared By: JLF | **Reviewed By:**
Date Prepared: 8/27/2018 | **Date Reviewed:**

Item	Value	Basis[1]
Direct Annual Costs (DC)		
Electricity		
Pressure Drop (in WC)	5	Pressure drop - catalyst bed
Power Output of Turbine (kW)	20,400	ISO Rating
Power Loss Due to Pressure Drop (%)	0.50%	0.1% for every 1" pressure drop
Power Loss Due to Pressure Drop (kW)	102	
Unit cost ($/kW)	$0.039	Estimated market value
Cost of Power Loss ($/yr)	**$290**	Based on operation of 73 hours/year
Operating Labor		
Catalyst labor req.	821	1/2 hr/shift of operation @ $60/hr
Ammonia delivery requirement (SCR)	1,440	24 hr/yr (3 deliveries per year) @ $60/hr
Ammonia recordkeeping and reporting (SCR)	2,400	40 hours per year @ $60/hr
Catalyst cleaning	2,400	40 hours per year @ $60/hr
Supervisor	123	15% Operating labor
Total Cost ($/yr)	**7,184**	
Ammonia		
Requirement (gal/hr)	51.3	19% aqueous ammonia
Hours of operation (per year)	73	hours/year
Unit Cost ($/gal)	$3.56	Default
Total cost ($/ton)	**13,344**	
Catalyst Maintenance		
Catalyst system maintenance labor	274	1/2 hr/operating day @ $60/hr
Ammonia system maintenance labor	21,900	1 hr/day @ $60/hr
Material	$22,174	100% x maintenance labor
Total cost ($/yr)	**44,348**	
Catalyst Replacement		
Catalyst Cost ($)	$193,282	Catalyst modules
Catalyst Disposal Cost ($)	-	Included in catalyst cost
Catalyst replacement labor	19,200	8 workers, 40hr, every 3 years @ $60/hr
Catalyst life (yrs)	3	n
Interest Rate (%)	7%	i
CRF	0.381	Amoritization of catalyst over 3 years
Total Cost ($/yr)	**80,967**	(Material + Labor Cost) * CRF
Indirect Annual Costs (IC)		
Overhead	$0	OAQPS SCR Assumption
Administrative charges	$0	OAQPS SCR Assumption
Annual Contingency	$0	OAQPS SCR Assumption
Property taxes	$0	OAQPS SCR Assumption
Insurance	$0	OAQPS SCR Assumption
Capital Recovery	$458,295	CRF * TCI (15 year life[3] @ 7% interest)
Total Indirect Costs ($/yr)	**458,295**	
Total Annualized Costs (TAC) ($)	**604,428**	
Total Pollutant Controlled (tons/yr) Natural Gas	**3.1**	Assume maximum of 3.4 tpy @ 90% reduction
Cost Effectiveness ($/ton)	**197,525**	

3 - *PSNH Generation Asset and PPA Valuation Report* , La Capra Associates, Inc, dated March 31, 2014