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May 30, 2006

Mr. J. Wick Havens, Chief
Division of Air Resource Management
Bureau of Air Quality
PA Department of Environmental Protection (PA DEP)
Rachel Carson State Office Building
P.O. Box 8468
Harrisburg, PA 17105-8468

Re: Exelon Comments Pursuant to 36 Pa.B. 2071 regarding Ozone Transport Commission (OTC) Candidate Control Measures for Electric Generating Units (EGUs), EGU Peaking Units, and Industrial, Commercial, Institutional Boilers

Dear Mr. Havens:

Exelon Corporation appreciates the opportunity to provide comments to PA DEP regarding the OTC Candidate Control Measures for Electric Generating Units (EGUs), EGU Peaking Units, and Industrial, Commercial, Institutional Boilers. Exelon Generation Company, LLC (hereafter all references will be to "Exelon" unless otherwise noted) owns approximately 8,500 megawatts of capacity in Pennsylvania, including nuclear, coal, gas, oil and pumped storage plants.

We commend PA DEP for soliciting Pennsylvania stakeholder comments on the various actions and emissions modeling scenarios that are currently being considered by the northeast Ozone Transport Commission (OTC). As you may be aware, Exelon has previously submitted comments to the OTC, both directly and as part of several industry coalitions. We are attaching our previous comments in several appendices for your reference as follows:

Appendix A: March 31, 2006 letter from Mr. Bruce Alexander (Exelon) to Mr. Chris Recchia, *Re: Ozone Transport Commission (OTC) Electric Generating Peaking Unit Candidate Control Measure*

Appendix B: March 20, 2006 letter from Joe Miakisz (M.J. Bradley & Associates) on behalf of eight northeast electric generating companies to Mr. Chris Recchia, *Re: OTC Electric Generating Peaking Unit Control Strategy Evaluation*

Appendix C: March 31, 2006 letter from Joe Miakisz (on behalf of the Clean Energy Group) to Mr. Chris Recchia, *re: Clean Energy Group Comments on OTC's Strawman Control Strategy for Electric Generating Units*

In addition to providing you with copies of our previous comments to the OTC, we would like to offer you the following additional comments:

EGU Peaking Units

As per our previous written comments to the OTC, we continue to believe that industry should have an opportunity to review and comment upon the datasets and assumptions that are being used by the OTC to establish baseline and future NOx emissions for "peaking units" and that a clear definition of such units should be developed if emission reductions from peaking generation are to be modeled. In particular, in the absence of a publicly available dataset, we do not know the extent to which the OTC's view of peaking units may be influenced by conservative "default" emission rates used by some units to report emissions where CEMS or stack tests are unavailable/uneconomic, as well as due to other factors. Industry could provide the OTC with valuable comments regarding its data and assumptions based on its primary role in managing these units.

Should the definition of peaking units extend to internal combustion engines, we have the same request that we expressed to PA DEP when it developed its Small Source NOx regulation that emergency diesel generators (EDGs) at nuclear power plants should be exempted from additional regulation, particularly regulation that would require prescriptive emission rates or additional pollution control equipment that could affect critical response time. Nuclear EDGs are prohibited under Nuclear Regulatory Commission (NRC) regulations from supplying power to the electric grid since these EDGs' sole purpose is to provide emergency power for the safe management of the nuclear plants' systems during emergency conditions. Therefore, there is no correlation, other than happenstance, between nuclear EDG operations (emergency or infrequent testing conditions) and peak ozone periods.

With regard to system reliability, we are very pleased that the OTC met with some of the regional Independent System Operators (ISOs), and industry, on May 16, 2006. We encourage these discussions to continue and, perhaps, they could be expanded to include our request that industry have an opportunity to provide constructive comment to the OTC regarding peaking unit emissions, economics, emission reduction incentives, operations and OTC baseline/modeling assumptions.

Control Measures for Industrial, Commercial, Institutional Boilers

Exelon's fossil affiliate, Exelon Power, is particularly concerned about this candidate control measure since it operates three (3) auxiliary boilers, each with a capacity greater than 100 mmBtu/hr. The OTC assumed, for modeling purposes, a 60% reduction in NOx emissions through the installation and operation of Low NOx Burners and Selective Non-Catalytic Reduction (SNCR) technologies. The furnaces of Exelon Power's auxiliary boilers are completely water cooled except the front wall. The exit temperature from each boiler is approximately 690°F. Optimum NOx reductions through the use of SNCR systems occur in the temperature window of 1400°F to 2200°F. Therefore, implementation of SNCR on Power's auxiliary boilers is technically infeasible. All three units currently utilize Low NOx Burners.

Exelon suggests that the OTC examine the option for Industrial, Commercial, Institutional Boilers to surrender NOx allowances for compliance rather than being forced to prescriptive controls. With regard to an allowance compliance sensitivity, the Pennsylvania Small Source NOx regulation provides one model of an option that could be modeled. Specifically, it provides for an actual/allowable test with the option for units to surrender NOx allowances equal to the amount that actual emissions exceed allowable emissions. Should the OTC determine to model this option as a sensitivity, it should be mindful of the fact that units < 25MW in size have received "zero" NOx allowances under CAIR and emission rates used to calculate allowable emissions should be reasonably based on unit fuel type, similar to the approach used in the Pennsylvania Small Source Regulation.

Thank you for considering these comments. Please feel free to call me at 215-841-5687 with any questions.

Sincerely,

Bruce Alexander

Bruce Alexander
EH&S Strategy Manager

Appendices

Appendix A

March 31, 2006 letter from Mr. Bruce Alexander (Exelon) to Mr. Chris Recchia, *Re: Ozone Transport Commission (OTC) Electric Generating Peaking Unit Candidate Control Measure*

Exelon Corporation
2301 Market Street
Philadelphia, PA 19101

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March 31, 2006

Mr. Chris Recchia
Executive Director
Ozone Transport Commission
444 North Capitol Street, Suite 638
Washington, DC 20001

Re: Ozone Transport Commission (OTC) Electric Generating Peaking Unit Candidate Control Measure

Dear Mr. Recchia:

Thank you for the opportunity to provide comments to the OTC regarding candidate control strategy options that the Commission is currently modeling and considering as possible additional, regional emission control measures beyond the requirements of the federal Clean Air Interstate Rule (CAIR). Our comments in this letter are limited to the OTC's work to evaluate peaking unit nitrogen oxide (NOx) emissions and emission reduction strategies for peaking units. Exelon is particularly concerned about this issue since Exelon Generation operates 42 peaking combustion turbines in the OTC states, representing approximately 978 MW of generating capacity.

Our current understanding of the OTC's "Control Measure Summary for Electric Generating Peaking Units" is that the candidate measures under consideration would require water injection retrofits at existing peaking combustion turbines in 2009 and the replacement of existing aeroderivative combustion turbines with dry low NOx combustion turbines in 2012. We are unclear what definition the OTC is using for "peaking combustion turbines". While Exelon realizes that the peaking unit control candidate measures identified by the OTC have been developed for modeling purposes and do not represent a final OTC position, we are very concerned that the current evaluation process, assumptions and data sets being used by the OTC are not completely transparent to the regulated community and do not incorporate valuable insights into peaking unit operations and emissions that the regulated community may be able to offer. Towards this end, you should have recently received a letter, dated March 20, 2006, from Joe Miakisz, submitted on behalf of Conectiv Energy, ConEdison, Constellation, Keyspan Energy, Exelon, NRG Energy, PSEG and PPL ("Ad Hoc Utility Group"). This letter specifically requests the opportunity to review the data being used by the OTC to evaluate EGU peaking units. Our hope is that the Ad Hoc Utility Group can effectively work with the OTC to provide constructive comment on the data and assumptions being used by the Commission to assess peaking units.

Based on the historic and expected future operations of Exelon Generation's portfolio of peaking combustion turbines, however, we do not believe that further regulation of these units is warranted for the following reasons:

Why Additional OTC Regulation of Peaking Units Are Not Warranted

- **CAIR and State Regulations Already Regulate These Units.** The Clean Air Interstate Rule (CAIR) already regulates combustion turbines greater than 25 MW in size. The vast majority of NOx emissions from peaking combustion turbines, in Exelon's case, occur at units that will be regulated by CAIR and that are currently regulated by the NOx SIP Call. Also, combustion turbines in southeastern Pennsylvania nominally rated at between 10MW and 25 MW in size are already currently regulated under the Commonwealth's Chapter 129.202 Small Source NOx Regulation (We believe that other OTC states were to have adopted similar small source NOx regulations several years ago pursuant to a previous OTC memorandum of understanding). Further, all of Exelon's combustion turbines are subject to permit conditions that limit capacity factors to low levels of operation. In terms of recent historic operations, during the period December 2002 to December 2005, rolling 12-month capacity factors at all of Exelon Power's combustion turbines in southeastern Pennsylvania, regardless of capacity rating, ranged from zero to three percent, with most units below 1 percent capacity factor. This suggests that further regulatory requirements are not necessary to limit emissions from these units.

- **Additional Controls Are Not Cost Effective.** Eighteen of the thirty-three combustion turbines operated by Exelon in southeastern Pennsylvania in 2002 (the year we understand that the OTC is modeling as a baseline) emitted less than 2 tons of NOx during the ozone season, with most of these units operating less than 50 hours during the ozone season (2002 was one of the highest generation years for Exelon's combustion turbines in the last five years). Whether water injection or dry low NOx technology, costs per ton for new technology at these low emission units would come at a cost of tens of thousands of dollars per ton ($44,000/ton for water injection alone based on discussion in the OTC straw proposal); far in excess of the cost effectiveness standards used by EPA in its CAIR. In fact, the two-staged proposal of requiring water injection retrofits at existing combustion turbines first, and then replacement of existing turbines with new equipment three years later would, on a combined basis, cost 10's of millions of dollars per combustion turbine when the cost of the replacement turbine is considered.

- **Regional Combustion Turbine Emissions May be Over-Stated.** Some peaking combustion turbine unit owners have elected to use default emission factors in reporting NOx emissions as provided for in 40 CFR 75. Exelon currently utilizes emission rates based on stack tests. The OTC should work with industry to determine the extent to which industry emissions may have been historically over-reported (e.g. in the 2002 base period the OTC is reviewing), as well as to understand the status of current reporting. Over-reporting of historic emissions may have a direct and significant effect on OTC projections of environmental benefit and cost effectiveness of controls. As previously indicated, Exelon is willing to work with the Ad Hoc Utility Group to offer the OTC input into combustion turbine emissions inventories.

- **Reliability and Fuel Diversity.** Peaking combustion turbines are vital to system reliability and black start capability. Exelon Power's combustion turbines operate almost exclusively on distillate oil, with only a few units capable of firing alternative fuels (two already operate on landfill gas, one can fire natural gas if needed). In considering reduced emissions from Dry Low NOx combustion turbine technologies, the OTC should not assume that units that currently use distillate as their primary fuel will switch to natural gas so that they can utilize DLN NOx combustion turbine technology to achieve lower NOx emission rates. In many cases, there is limited or no access to natural gas at Exelon Power's combustion turbine locations and building gas infrastructure would either be cost prohibitive or impractical; further, maintaining fuel diversity at units that may be called upon for black start support is very important to maintaining system reliability. We would suggest that any OTC modeling assumes continued use of existing primary fuel types.

- **Modeling Sensitivities.** While Exelon does not believe that further regulation of peaking combustion turbines is warranted, we suggest that the OTC examine two sensitivities as part of its modeling: 1) a program exemption for low capacity factor peaking units, and 2) the option for peaking combustion turbines to surrender NOx allowances for compliance rather than being forced to prescriptive controls, or unit replacement. With regard to an allowance compliance sensitivity, the Pennsylvania Small Source NOx regulation provides one model of an option that could be modeled. Specifically, it provides for an actual/allowable test with the option for units to surrender NOx allowances equal to the amount that actual emissions exceed allowable emissions. Should the OTC determine to model this option as a sensitivity, it should be mindful of the fact that units < 25MW in size have received "zero" NOx allowances under CAIR and emission rates used to calculate allowable emissions should be reasonably based on unit fuel type, similar to the approach used in the Pennsylvania Small Source Regulation.

Finally, a number of stakeholders have requested that the OTC work with the regional power pools and state public utility commissions to understand the role of peaking combustion turbines in the operations and reliability of regional power grids. We encourage the OTC to meet with these organizations to discuss these issues. It would also be useful for the OTC to ensure that it considers how any of its proposals would interact with the regional power pool economic market structures. As an example, peaking combustion turbines receive capacity payments from the regional power pools based on combustion turbine availability to operate. It is important to power generation owners that the economic consequences of any new emission requirements are considered by the OTC before finalizing any new program requirements. For example, efforts to further limit capacity factors at peaking combustion turbines could result in incremental lost revenue to generators, with potentially no incremental environmental value. In Exelon's case, our peaking combustion turbines have typically operated at well below their already low permit capacity factor limits. Further limits on capacity factor at these units would likely simply erode Exelon's financial position with little or no additional emission reductions.

Thank you for considering these comments. Please feel free to call me at 215-841-5687 with any questions.

Sincerely,

Bruce Alexander

Bruce Alexander
EH&S Strategy Manager

Cc: Ms. Joyce Epps, Director, PA DEP Bureau of Air Quality

Appendix B

March 20, 2006 letter from Joe Miakisz (M.J. Bradley & Associates) on behalf of eight northeast electric generating companies to Mr. Chris Recchia, *Re: OTC Electric Generating Peaking Unit Control Strategy Evaluation*

M. J. Bradley & Associates, Inc.

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March 20, 2006

Mr. Chris Recchia
Executive Director
Ozone Transport Commission
444 North Capitol Street, Suite 638
Washington, DC 20001

Re: OTC Electric Generating Peaking Unit Control Strategy Evaluation

Dear. Mr. Recchia:

I am writing this letter to you on behalf of the following electric generating companies—Conectiv Energy, Con Edison, Constellation, Keyspan Energy, Exelon, NRG Energy, PSEG and PPL ("the Companies"). These companies own and operate a large number of combustion turbines in the OTR that are used to meet peak electricity demands in the region (for this reason they are referred to as "peaking units"). These units often serve other important purposes in maintaining reliability of the electric system such as providing spinning reserve capacity with the ability for rapid load pick-up in the event of a system contingency, and voltage support.

Since peaking units play such an important role in maintaining reliability of the electric system, the Companies are concerned that these units have been targeted by the OTC as a potential control strategy option to assist the region in achieving attainment with the 8-hour ozone standard. The strawman control strategy that the OTC is considering for peaking units consists of the retrofit of water injection technology in Phase 1 (2009) and the replacement of these units with newer dry low NOx-based simple-cycle turbines in Phase 2 (2012).

The Companies have several concerns with the strawman proposal being considered for peaking units, which we will identify in detail in subsequent comments we plan to file prior to the end of this month. However, we would like to bring to your attention an initial concern that could bear significantly upon the OTC's evaluation of this control strategy option.

The Companies' concern is that the OTC may not be using representative emission rates for combustion turbines. The reason that we say this is that the emissions data that has been submitted by the Companies and others to EPA and the states under the OTC NOx Budget Program and EPA NOx SIP call is based on specific requirements of 40 CFR Part 75 that allow the use of a very conservative generic default emission rate or a lower, but still inflated "unit specific" emission rate based on stack tests. These generic emission factors are generally more than 50% higher than actual emissions, while the unit specific rate, based on conservative test and statistical requirements, is 10-25% higher than the actual rate, especially on the peak, hot humid days (high specific humidity lowers NOx emissions) that the OTC is focusing on. Stack test data is available for certain units that provide a more representative and accurate reflection of actual emissions.

In order that the OTC may perform a representative assessment of the costs and air quality benefits associated with the strawman control strategy for EGU peaking units, the Companies believe it would be useful at this early stage in the evaluation process to have the opportunity to review the current emissions inventory for EGU peaking units that the OTC is using and to provide the OTC with feedback on the representativeness of the inventory. Accordingly, we request a copy of the emissions inventory for EGU peaking units that has been developed for the OTC. We would also like to know how these units are being modeled in cost and air quality assessments. For example, how many days and hours during the ozone season are these units assumed to run in the future? Are any new units being assumed for installation in the future that would displace the operation of the existing units? Also, if not already planned by OTC, we recommend that any controls proposed for peaking units be modeled independent of reductions from other source categories to isolate the effects of peaking units on ozone levels.

So that we are all on the same page in terms of the control strategy being considered, we also request that the OTC define exactly what it means by an "EGU peaking unit."

Your consideration of the above requests would be most appreciated.

If you have any questions or would like to discuss this matter, representatives of the above-cited companies would be happy to meet with you and/or your staff. I can be reached at (978) 369-5533.

Sincerely,

Joseph A. Miakisz
Senior Consultant
M.J. Bradley & Associates

Xc: OTC Air Quality Directors

Dan Cunningham (PSEG)
Cathy Waxman (Keyspan)
Tom Keller (PPL)
Tom Hmiel (Con Edison)
Gary Helm (Conectiv)
Bruce Alexander (Exelon)
Orlando Cartagena (NRG)
Edwin Much (Constellation)

Appendix C

March 31, 2006 letter from Joe Miakisz (on behalf of the Clean Energy Group) to Mr. Chris Recchia, *re: Clean Energy Group Comments on OTC's Strawman Control Strategy for Electric Generating Units*

The Clean Energy Group

Michael J. Bradley
Director
The Clean Energy Group
47 Junction Square Drive
Concord, MA 01742
978-369-5533
978-369-7712

March 31, 2006

Mr. Chris Recchia
Executive Director
Ozone Transport Commission
444 North Capitol Street, Suite 638
Washington, DC 20001

Subject: Clean Energy Group Comments on OTC's Strawman Control Strategy for Electric Generating Units

Dear Mr. Recchia:

The Clean Energy Group (CEG) is pleased to offer the following comments regarding the Ozone Transport Commission's (OTC's) strawman control strategy for the electric generating unit (EGU) sector. CEG is a coalition of electric generating and electric distribution companies that share a commitment to responsible environmental stewardship. Members include Calpine; Conectiv Energy; Consolidated Edison, Inc.; Entergy Corporation; Exelon Corporation; KeySpan; the New York Power Authority; NiSource, Inc.; Public Service Enterprise Group, Inc.; Sacramento Municipal Utility District and Sempra Energy.

With plants in operation or under development within the Northeast Ozone Transport Region and throughout the country, member companies have a generation mix of more than 120,000 MW that includes substantial coal-, oil-, and gas-fired generation, as well as nuclear, hydroelectric and renewable assets. Thus, CEG has a substantial interest in the control strategies being considered by the OTC to comply with the 8-hour ozone and $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS), particularly those involving EGUs and EGU peaking units.

The CEG companies offer the following comments for your consideration:

1. The OTC should not adopt a CAIR-Plus program for EGUs unless a similar program is adopted by other states in the East.

At the special meeting of the OTC convened on February 22-23, 2006 it was reported that representatives of the OTC states have been meeting on a collaborative basis over the past few months with representatives of certain Midwest states (e.g., Ohio, Indiana, Illinois, Michigan and Wisconsin) to explore the possibility of a "super-regional" CAIR-Plus program, and that future meetings are planned. In CEG's view, the only way that a CAIR-Plus program might be justified in the OTC states is if a comparable program is also implemented in other eastern states.

Based on the modeling of the potential air quality benefits associated with various control strategy options performed by the OTC thus far, it appears that a CAIR-Plus program governing EGUs implemented only in the OTC states would result in limited benefits in terms of reductions in ozone levels in the Northeast and Mid-Atlantic states. In fact, a majority of the benefits would occur over the Atlantic Ocean, as opposed to populated land areas.

In contrast, the modeling suggests that a CAIR-Plus program implemented on a super-regional basis would result in fairly substantial and widespread ozone reduction benefits across the super-region.

In terms of cost and potential economic impacts, a CAIR-Plus program implemented only in the OTC states would impose additional costs on electric generators in the Northeast and Mid-Atlantic states and increase the price of electricity in the region. Electric generators in these states are already at a competitive disadvantage in these states relative to certain electricity producers in the Midwest due to disparities in current environmental control requirements and anticipated air quality programs (e.g., RGGI, states' legislation, etc.). The competitive advantage held by certain Midwest generators allows them to sell more power in wholesale markets such as PJM than they would otherwise be able to. Perversely, not only does the competitive advantage enjoyed by certain Midwest generators due to less stringent environmental requirements allow them to increase their market share in the Northeast and Mid-Atlantic regions, but the greater utilization of their higher emitting fossil fuel-fired electric generating units results in more air pollution being transported to the Northeast and Mid-Atlantic regions. As one air quality regulator from New Jersey recently remarked in a survey conducted by NARUC:

> "Since New Jersey is an area where energy is supplied by a regional market, which has less stringent and weaker federal standards, this can result in more supply being provided from out of state sources. Currently between 20-30% of energy is supplied by out-of-state facilities, but these facilities can represent 60-75% of the CO_2 load from electrical use in the state."

If the OTC states were to adopt a CAIR-Plus program governing EGUs, without other eastern states doing something similar, not only would the ozone reduction benefits in the region be minimal, but the unlevel playing field that currently exists between generators in the OTC states and certain Midwest generators would become more tilted in favor of the Midwest, resulting in more economic hardship for the OTC states and more air pollution being transported into the region from the Midwest. Such a policy, in CEG's view, makes no sense for the OTC states to consider.

2. The OTC should limit its efforts to evaluating additional control strategies to reduce ozone levels in the region

Based on modeling performed to date by EPA and the OTC which shows that even after all "on-the books" (OTB) and "on-the-way"(OTW) emission controls are implemented several highly populated areas of the region will not be able to achieve attainment with the 8-hour ozone NAAQS, CEG understands the rationale for considering additional control strategies aimed at achieving compliance with the 8-hour ozone standard. However, notwithstanding charter issues associated with the Northeast *Ozone* Transport Commission, CEG does not understand why the OTC also appears to be committed to evaluating additional control strategies related to $PM_{2.5}$ and mercury.

When this issue has been raised by certain stakeholders at OTC meetings the response was that the environmental commissioners representing the states comprising the OTC wear different hats and that addressing $PM_{2.5}$ and mercury is part of their responsibilities. It has also been said that reductions in SO_2 emissions, for example, are not only beneficial in terms of reducing ambient $PM_{2.5}$ levels but these reductions are also beneficial in reducing visibility impairment, acid rain, etc.

The OTC was formed under the Clean Air Act because Congress recognized that the Northeast ozone problem in the Northeast is a regional phenomenon and needed a regional focus, which led to the OTC cap and trade program. Subsequently, the Ozone Transport Assessment Group (OTAG) process heightened the attention to transport and the necessity to reduce transport for progress to attainment in eastern U.S. Individual states, acting alone on a parochial basis, could not be counted on to take sufficient action to effectively address the problem.

The fine particulate problem is similar to the ozone problem in that, to a large degree, it is caused by the transport of secondary precursor emissions (i.e., SO_2 and NOx). Unlike the situation with the 8-hour ozone standard, however, the modeling performed to date by EPA (OTC has not shared with stakeholders the results of any $PM_{2.5}$ modeling that it has performed), indicates that the OTR will be in attainment with the $PM_{2.5}$ standard once all OTB and OTW emission controls are implemented (with the exception of one small area in Western Pennsylvania that is impacted by local sources of $PM_{2.5}$).

For this reason, CEG does not believe that the OTC should pursue a CAIR-Plus program that includes stricter SO_2 caps than required under the federal CAIR. In terms of other potential benefits that additional SO_2 reductions may provide such as improvements in visibility and reductions in acid rain, there is already a regional process in place to address emission control strategies to comply with the federal Clean Air Visibility Rule (also referred to as the Regional Haze Rule) and BART requirements, namely the work of Regional Planning Organizations such as MANE-VU.

A similar situation exists with respect to mercury. Many states do not feel that the federal Clean Air Mercury Rule (CAMR) goes far enough, or quickly enough, in terms of reducing emissions from coal-fired power plants. On this basis, several states, both within and outside the OTC, have proposed stricter mercury rules. Additional states are considering taking similar steps. The CAMR is also being litigated in federal court. Accordingly, CEG sees no reason why the OTC should be considering adopting a policy on mercury emissions.

For the reasons cited above, CEG recommends that the OTC focus its efforts on evaluating the efficacy of additional control strategies to achieve attainment with the 8-hour ozone standard via NOx and VOC reductions, and not further evaluate additional reductions of SO_2 and mercury reductions from the EGU sector.

3. The OTC should abandon, or at least substantially modify, its strawman proposal for EGU *peaking units*

The OTC strawman proposal for EGU peaking units calls for the installation of water injection technology on these units by 2009 and the replacement of all existing aeroderivative turbines with newer Dry-Lo NOx based simple-cycle turbines at some point thereafter (e.g., 2012). CEG believes that the strawman proposal is extremely unreasonable, in some respects may be illegal and, if implemented in its current form, could seriously undermine the reliability of the electric system in the region.

Most existing peaking units are simple-cycle frame or aeroderivative turbines. These units are generally the last units dispatched during periods of peak load when electrical demand is the highest but are the first units dispatched in an emergency due to their quick start capability. Many of these units are needed to meet spinning reserve requirements to ensure an adequate power supply. The quick start capability of these peaking units also assists in grid stabilization.

By OTC's own estimates, the capital cost of retrofitting water injection on a typical single-cycle combustion turbine is about $1 million per engine. On a typical unit, the marginal cost-effectiveness of this strategy would be approximately $44,000 per ton of NOx reduction. *This is about an order of magnitude higher than what EPA considers cost-effective reductions of NOx emissions from EGUs represented in its CAIR rule.* Additionally, this estimate could increase significantly depending on actual emissions from a particular unit and the number of engines serving each a particular generator.

As unreasonable as CEG views the OTC's first phase strawman control strategy for EGU peaking units, the second phase option of replacing all existing aeroderivative turbines with Dry-Lo NOx based simple-cycle turbines is even worse. First of all, CEG respectfully questions whether the states have the authority to impose such a requirement. It is one thing to establish emission limitations, even emission limitations where the cost of compliance would cause an owner to retire a particular unit, but requiring an existing electric generating unit to be replaced with a new unit appears unprecedented. Moreover, we do not believe that such a requirement could lawfully be imposed under existing state statutes.

Another serious concern CEG has with the second control strategy option is the potential cost. As indicated above, the marginal cost of achieving an approximate 40% reduction in NOx emissions from these units by retrofitting water injection is approximately $40,000 per ton. With only three years to amortize the costs of this investment (from 2009 to 2012), the strawman calls for these units to be replaced with Dry-Lo NOx turbines in Phase 2 at a cost as high as $1,200-$1,300/kW per unit. We have not calculated the costs associated with this option but it would certainly not be cost effective. This is not to mention the *feasibility* of replacing the literally hundreds of aeroderivative peaking turbines that exist in the OTC in this timeframe.

Furthermore, when contacted, Pratt and Whitney stated that the DLN combustor for the FT4 units is no longer offered due to flame stability problems.

Additional concerns that CEG has with the strawman control strategy for EGU peaking units include the following:

- While installing water injection technology on single-cycle combustion turbines will reduce NOx emissions, it will also increase carbon monoxide (CO) and likely $PM_{2.5}$. Water injection lowers the peak flame temperature and creates a non-homogeneous combustion region, thereby reducing overall complete combustion of the fuel, leading to higher CO, a product of incomplete combustion and higher particulate emissions.

  CEG is concerned not only with the potential environmental impacts associated with these increases in collateral emissions, but the distinct possibility that these increases in collateral emissions will trigger NSPS, NSR and/or CT MACT requirements. If this proves to be the case, even greater costs than outlined above could be faced by the owners/operators of peaking units, increasing the likelihood that these units would have to be shutdown.

- Most existing combustion turbines are not equipped with CEMS and use alternate monitoring methodologies as allowed in 40 CFR Part 75. To the extent that these units are required to install CEMs for compliance, they would incur significant additional monitoring costs. The estimated cost of a CEM is $200,000-$300,000 per unit or more. This estimate does not reflect the manpower to maintain and service the units. Many combustion turbines are located at unmanned sites so a crew is needed to maintain the systems.

- The nature of these facilities (i.e., unmanned) may also be a problem in terms of monitoring. If companies are required to install water injection and take a permit limit, they would have to monitor if the water injection is working properly. If the system went out of compliance and a company couldn't get a technician there quickly a system operator would be forced to shut the unit off, which could present a reliability issue.

- It should also be recognized that many existing peaking combustion turbines are located in areas without access to natural gas transmission and are fueled by distillate oil. For many of these locations, building natural gas transmission capacity to fuel very low capacity factor units would be cost prohibitive and, in some cases, practically just not feasible due to non-existent rights-of-way. While dry-low NOx combustion turbines may achieve greater NOx reductions versus some existing combustion turbines, the OTC should be careful not to assume that a DLN technology mandate would achieve the DLN NOx emission rates associated with natural gas. Many peaking units would need to continue operating on distillate oil at NOx emission rates higher than those that can be achieved when firing natural gas. In any analysis performed by the OTC, continued use of the existing unit's primary fuel should be assumed. As an aside, fuel diversity, particularly for "black start" peaking units, is critical to managing system reliability and forcing all units to natural gas would increase system risk.

With respect to the potential benefits side of the equation, CEG has not seen the results of any air quality modeling of the strawman proposal for EGU peaking units. Therefore, we cannot assess the potential ozone reduction benefits that may result from implementation of the proposal. Based on preliminary modeling results shared with stakeholders of other potential ozone reduction strategies implemented only in the OTR, however, it would not be unreasonable to conjecture that these benefits may be very limited in terms of magnitude and population exposure. If not already performed or planned, CEG recommends that the OTC conduct air quality modeling aimed at isolating the potential ozone reduction benefits associated with the strawman proposal for EGU peaking units.

Finally, if the OTC is intent on reducing emissions from EGU peaking units as part of a CAIR-Plus program, CEG strongly recommends that maximum compliance flexibility be afforded. The OTC states should identify the amount of mass NOx emissions from these units that is warranted and allow the owners/operators of the affected units to determine the most cost-effective way to achieve the reductions which may include reducing emissions at the peaking units, reducing emissions at other (non-peaking units), surrendering allowances, etc.

4. Establish separate SO_2 emission limitations for residual oil-fired units.

In Phase 1, the OTC strawman proposal for SO_2 calls for a cap based on an emission rate of 0.24 lbs/mmBtu. In Phase 2, the cap is reduced based on an emission rate of 0.14 lbs/mmBtu. As indicated in Comment #2 above, CEG does not believe that the OTC should be pursuing a CAIR-Plus program that includes stricter SO_2 caps than required under the federal CAIR. Notwithstanding this position, CEG would like to point out that these low limits would force most residual oil-fired steam units to burn lower sulfur fuel and co-fire natural gas to achieve compliance, reducing fuel diversity and driving up the cost of fuel. Further, at some generating station locations, natural gas is not available for co-firing.

Also, in contrast to coal-fired electric generating units, flue gas desulfurization (FGD) has not historically been used at oil-fired facilities to comply with SO_2 emission limitations. To CEG's knowledge, there are no existing oil-fired steam electric generating units in the U.S. equipped with FGD for control of SO_2 emissions. The cost of installing FGD on oil-fired units burning relatively low sulfur oil would not be cost-effective when viewed on a $/ton of SO_2 removed basis, particularly in view of the fact that the majority of oil-fired units are used for peaking or intermediate service which would drive up the $/ton removal costs. Based on a cursory analysis of installing FGD at one of the CEG member company's oil-fired units, it is estimated that the cost of installing FGD on an oil-fired unit would exceed $3,000 per ton of SO_2 removed. In addition, at many sites where residual oil-fired EGUs are located, space limitations would prohibit installation of an FGD unit.

For these reasons CEG suggests that if the OTC is to ultimately require additional SO2 emission reductions from EGUs beyond the federal CAIR requirements, it should not impose any additional requirements on oil-fired units beyond consideration of lower-sulfur oil.

5. Comments on modeling being performed

The OTC is using CALGRID (screening) and CMAQ (SIP) modeling to project reductions in 8-hour ozone levels associated with various local and regional control strategies. PROMOD is being used to evaluate the economic, energy and emissions impacts associated with various control strategy options. CEG offers the following comments related to these modeling activities.

CALGRID and CMAQ Modeling

- If the OTC is intent on pursuing a CAIR-Plus program for EGUs, regardless of whether or not a similar program is adopted by other Eastern states then the OTC should conduct a modeling run that assumes that the only additional control strategy that is adopted beyond OTB and OTW controls is a CAIR-Plus program implemented in the OTR. The modeling results shared with stakeholders to date shows the air quality benefits of a CAIR-Plus program implemented on a super-regional basis (OTR and LADCO) and the benefits of additional local/regional controls (not just CAIR-Plus) within the OTR. However, CEG believes that it would be very useful to attempt to isolate the potential benefits of implementing a CAIR-Plus program for EGUs only in the OTR.

- Based on the modeling results shared with stakeholders thus far, it appears that the modeling is being calibrated to only one or two high ozone episode periods in the past. Recognizing resource constraints on the number of modeling runs that can be reasonably performed, it seems to CEG that with so much at stake from the standpoint of the regulated community (in terms of potential compliance costs) that the air quality modeling should be based on multiple historic high ozone episodes.

- The potential ozone reduction benefits associated with implementation of the recently adopted RGGI program by seven states in the Northeast should be modeled (on the presumption that implementation of RGGI may result in NOx reduction co-benefits from EGUs)

- Also, the effect of state renewable portfolio standards should be included with the same deployment assumptions as used by the states to justify their programs.

PROMOD Modeling

- Considering that a CAIR-Plus program adopted for EGUs, along with the recently adopted RGGI program, could have substantial economic and energy impacts on the EGU sector, it is important that the *combined* impacts of these two programs be evaluated in the PROMOD modeling.

- PROMOD modeling results are sensitive to certain input parameters and assumptions used in the model such as fuel prices, electricity demand growth and response, and the cost and performance of emission control technologies. To ensure that the OTC's modeling results are robust, it is important that a range of input values and assumptions be evaluated for those parameters that the modeling results are most sensitive to. In addition, to ensure transparency of the evaluation process, the OTC should provide stakeholders with information on the key inputs and assumptions used in the modeling.

If you would like to discuss the comments above, representatives of the CEG member companies would be happy to meet with you and your staff. To arrange for such a meeting, or if you have any initial questions regarding the CEG comments, I can be reached at (978) 369-5533.

Sincerely,

Joseph A. Miakisz
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The Clean Energy Group