design characteristics, a separate NSPS subcategory specific to IGCC should be established. Issues that this subcategory would have to consider include:

- operating scenarios when coal-based syngas is not consumed by the combustion turbines, but by other process systems, such as a flare, thermal oxidizer, etc.
- operating scenarios when the combustion turbines are firing only natural gas or co-firing natural gas and coal-based syngas
- operating scenarios when the combustion turbines are consuming coal-based syngas and natural gas is combusted in duct burners in the heat recovery steam generator
- operating scenarios when coal and other carbonaceous compounds (petcoke, biomass, municipal solid waste, etc.) are simultaneously being gasified to produce a syngas
- combustion turbines that use synthetic natural gas (coal-based syngas) that is produced offsite by another facility

G. EPA has incorrectly assessed the performance capabilities of new coal-based generating technologies that are designed with CCS

EPA uses a single NETL report[327] from 2010 to assess the performance capabilities of new coal-based generation technologies.[328] This report was discredited at length in comments above regarding the flawed CCS cost analysis performed by the agency. Likewise, the report is unreliable for assessing the performance of highly efficient generation technologies due to (i) a narrow reliance on dated vendor supplied conceptual designs for coal-based generation technologies that have **never** been constructed, operated, or proven; and (ii) an evaluation that is restricted to generation technologies that only use bituminous coals, with **no consideration** given to the use of lower rank coals.

In fact, no data has been found that validates the related emission rates from this report that EPA purports has been or are capable of being demonstrated. EPA blindly accepts the information without any consideration of the actual performance of operating units. Such operating data is readily available through the EPA Clean Air Markets Division (CAMD) database. At a minimum, EPA should thoroughly analyze operating data from the CAMD database to inform their assessment of what emission rates are being demonstrated in practice. The agency should then expand this analysis by engaging operators, vendors, and equipment manufactures to evaluate performance drivers and to determine emission rates that are representative and sustainable for various coal-based generation technologies.

[327] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev 2, DOE/NETL–2010/1397 (Nov 2010)
[328] 79 Fed. Reg. 1468 (January 8, 2014)

H. The BSER determination for fossil fuel-fired boilers and IGCC units must be based on highly efficient generating technologies

EPA made no attempt to seriously evaluate the current status and future prospects of highly efficient generation technologies. Across the world, significant progress is occurring to successfully develop more highly efficient technologies that are establishing new standards for the performance of coal-based generating technologies. EPA's decision to eliminate highly efficient technologies on the basis of insufficient emission reductions and the lack of future technology development is incorrect and should be replaced with an honest, objective review of such technologies. Clearly, high efficient technologies have the potential to yield significant emission reductions. The prospects for significant advancements in high efficiency technologies is widely recognized and would be more aggressively pursued if such technologies were determined to be the BSER.

In evaluating highly efficient generation technologies, EPA should:

- review prior EPA evaluations of highly efficient generation technologies;[329]
- perform a detailed evaluation of operating data that are readily available in databases maintained by the agency;
- evaluate the demonstrate performance of international efforts and current research and development program so that the current and long-term capabilities of highly efficient generating technologies be more accurately quantified;

From these evaluations, informed conclusions can then be made regarding any differences in the performance capabilities of specific generation technologies and/or for specific fuel characteristics that would drive decisions regarding the appropriate subcategories and corresponding emission rates that represent the best system(s) of emission reduction. The result will be technically proven and legally acceptable standards based on the use of highly efficient generating technologies for at least the following subcategories: (i) non-IGCC coal-based generating units; (ii) fossil-fuel fired IGCC generating units; and (iii) natural gas-fired boiler generating units.

[329] For example, EPA evaluated efficiency in the following reports: (a) "PSD and Title V Permitting Guidance for Greenhouse Gases" March 2011; (b) "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units" October 2010; and (c) "Environmental Footprints and Costs of Coal-Based IGCC and Pulverized Coal Technologies" July 2006

XI. Flaws in the Regulatory Impact Analysis and Supporting Economic Analyses

EPA's methodology for assessing the costs and benefits of this proposed rule is incomplete and factually disconnected from scientific and economic realities. EPA has not effectively accounted for the potential impacts of this rule under a full range of possible future market conditions and thus has hidden the true potential costs of this regulation. Instead of robust scenario analysis, EPA has overly relied upon "one-off" calculations and comparisons. Policymakers and the general public need to be fully informed of the potential costs of this proposed rule through a comprehensive and well-informed analysis.

A. Cost Analysis

EPA erroneously concluded that the proposed rule will have negligible costs or impacts on society based on the flawed premise that no new coal plants will be built absent this rule. This is inconsistent with EIA scenarios showing new unplanned coal additions prior to 2020[330] and significant additions of new coal generation under certain model scenarios in later years. EPA arbitrarily examined the costs of the rule only through 2022, based on the eight-year review cycle for Section 111(b) regulations. This is a significant and glaring omission in the analysis in that truncation of the regulatory period in question hides the true potential cost of the regulation. Furthermore, even with an eight-year regulatory review cycle, this regulation is likely to set a *de facto* emission rate limit for future review periods.

New baseload generating capacity takes a number of years to plan, permit, engineer and construct. Some generating assets coming online after 2022 will have to be planned and permitted prior to 2022, and thus will be subject to the proposed standard. EPA's argument that reviewing the NSPS within eight years renders post-2022 analysis irrelevant is incorrect. Truncating the analysis based on a presumed future regulation is also at odds with previous EPA assertions that it will not speculate on future rulemakings in its modeling efforts. EPA states in the documentation for the IPM results that the base case represents "a projection of electricity sector activity that takes into account only those Federal and state air emission laws and regulations whose provisions were either in effect or enacted and clearly delineated at the time the base case was finalized."[331]

---

[330] www.eia.gov/oiaf/aeo/tablebrowser/

[331] www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter1.pdf

Equally troubling is EPA's reliance upon a single forecast of projected new generation using coal and natural gas prices that run out to only 2022. It is impossible to say that new coal-fired generation is not going to be cost-effective in the future based on a single modeled outcome or without considering potential coal and gas prices in the post-2022 time period. Other scenarios recently developed by EIA indicate that, under varying market conditions projected in the past, some new generation may be built prior to 2022 (~300 MW) and many other new coal units may in fact be built post-2022.[332] EPA made little effort to quantify the impacts of these alternative scenarios due to the arbitrarily truncated period for which it chose to analyze impacts. Furthermore, EPA failed to examine any additional combination of scenarios beyond those previously published. As an example, under a scenario where natural gas resources are less economically developed and the Climate Uncertainty Adder (to be discussed later) is removed dramatically more coal builds would occur.

Trends in planned and projected generation tend to oscillate substantially, largely due to the volatility in fuel commodity markets. As an example, less than six years ago, in the 2008 Annual Energy Outlook, EIA forecast 89,000 MW of new unplanned coal additions by 2030. Just eight years ago, in the 2006 Annual Energy Outlook, EIA forecast 145,000 MW of unplanned coal additions. Immediately prior to those forecasts, however, there was an unprecedented build-out of new natural gas combined cycle capacity, with the belief that those facilities could displace existing coal generation. Thirty years prior to the natural gas build-out, there was a similar boom with nuclear power, accompanied by the prediction that nuclear energy would be "too cheap to meter." These previous forecasts and historical build cycles illustrate that future generation options and projections are extremely sensitive to future commodity pricing, regulatory requirements, and external events. A myopic view of these influences leads to wasteful and disruptive boom and bust cycles in generation development.

The electric utility industry is currently in a unique period in which material (*e.g.*, steel and concrete) and fuel costs for coal-fired generation have seen dramatic increases at the same time that natural gas prices have reached record lows not seen in the past decade, and the demand for electricity has been suppressed due to the prolonged recession and benign weather. However, many analysts expect natural gas prices to rise significantly in the future, as the near term glut of natural gas eventually dissipates. Recent spikes in natural gas pricing due to cold weather and

[332] www.eia.gov/oiaf/aeo/tablebrowser/

high levels of consumption have illustrated that this effect can and will occur. This situation could be exacerbated in the near future as the Mercury and Air Toxics Standards rule will force retirement of otherwise economical coal-fired capacity that can only be replaced with NGCC technology, which will sharply increase natural gas demand in a compressed time period.

Natural gas pricing has historically been extremely volatile and is the largest determinant of what type of new electric capacity will be built, due to its strong correlation with power pricing. EPA's RIA states on page 4-31 that:

> "*The natural gas market in the United States has historically experienced significant price volatility from year to year, between seasons within a year, and can undergo major price swings during short-lived weather events (such as cold snaps leading to short-run spikes in heating demand). Over the last decade, gas prices (both Henry Hub prices and delivered prices to the power sector) have ranged from below $3 to nearly $10/mmBtu on an annual average basis.*"

AEP agrees and notes that domestic and international natural gas prices have historically experienced seasonal and annual volatility that resulted in significant spikes for periods of time. The extreme volatility in natural gas pricing should lead to the logical conclusion that structuring the cost benefit/analysis for this rule on a single gas forecast extending through only 2022, with prices near the lowest levels of the past decade, is not a rational or prudent approach. Instead, multiple natural gas price trajectories should be examined in conjunction with the cost analysis for the rule.

While EIA has examined the role that higher electricity sales and lower yields from shale gas could have on new capacity decisions, there are other factors that could have even more dramatic impacts on natural gas pricing and new build economics. For example, a move to gas liquefaction and export within either the U.S. or Canada has the potential to drive up domestic natural gas prices to levels seen internationally, which can be three to four times higher than current domestic prices.[333] EPA's IPM model does not take into account the development of these facilities, even though announced facilities and current market conditions suggest they will be developed. Additionally, a drop in world oil prices could slow down oil and natural gas liquids production activities, reducing the supply of associated gas and increasing the price of natural gas.

---

[333] www.forbes.com/sites/energysource/2012/06/13/theu-s-has-a-natural-gas-glut-why-exporting-it-as-lng-is-a-good-idea

Furthermore, EPA's economic modeling used in this rulemaking has not appropriately assessed the impacts of the final MATS rule and other pending regulations, which will lead to the retirement of many coal-fired generating units, further increasing the demand and hence the price for natural gas. The associated reduction in coal use will also influence coal pricing (and reduce coal prices), making new coal fired generation more viable economically. Notably, when spreads between gas and coal prices reach approximately $4 per MMBtu, coal plants become economic to build relative to combined cycle gas plants. Historically there have been many periods where these spreads have existed between gas and coal prices, such as the period from 2003 to 2008. Thus, shale gas recovery levels are only one of many factors that can influence natural gas pricing. A broader range of scenarios needs to be explored within the cost-assessment. For each scenario, the cost of this regulation should be assessed, using at least a 30-year time horizon.

B. Levelized Cost Analysis

Numerous comparisons are made using the Levelized Cost of Electricity (LCOE) within the RIA and the proposed rule, in an attempt to illustrate that (a) new coal is not the currently preferred choice for new generation and (b) coal with carbon capture is of a similar cost to new nuclear as second baseload power option. While the LCOE of electricity is often used within the electric industry as a comparative tool, the results of LCOE analysis can be easily biased by incorrect or misleading assumptions, as is the case as presented with the proposed rule. In addition, as discussed above in comments on the cost analysis performed in the BSER, the reports that EPA relies upon for LCOE information are insufficient for performing reliable analyses.

Underlying the LCOE analysis is EPA's broad assumption that new NGCC units can meet its proposed standard of performance, which is 1,000 lb CO_2/MWh of electricity generated on a gross basis. However, one study has indicated that many smaller plants will not be able to meet this standard.[334] Additionally, even efficient units could have trouble meeting the standards if gas prices should increase, changing the duty cycle of the units, and creating additional

[334] See Matthew J. Kotchen and Erin T. Mansur, How Stringent is the EPA's Proposed Carbon Pollution Standard for New Power Plants?, at 9 (Apr. 25, 2012), available at www.dartmouth.edu/~mansur/papers/kotchen_mansur_co2standards.pdf (finding that "71 percent of the [combined cycle gas turbine] units scheduled to come on line through 2017 would have CO2 emission rates that meet the target").

inefficiencies associated with cycling or ramping of output. EPA should include in its LCOE analysis the additional costs of having to build larger and more efficient units to cope with temporary, intermittent, or unexpected operating conditions. EPA should also conduct a detailed analysis of the effect of unit cycling on meeting the standard. If units must be forced to run even if their cost of operation exceeds the power price to meet the efficiency standard, the increased operational cost should be considered in the cost analysis.

The cost and performance data used by EPA on NGCC is overly optimistic. EPA cites capital cost for advanced combined cycle of $821/kW in 2012$ and an efficiency of 50.2% based on a NETL report. However, AEP's experience suggests total installed capital costs of 40+% higher. Furthermore, NGCC operating experience indicates that average achievable efficiency over the course of a year are several percentage points less than EPA is assuming due to the startup, shutdown, and cycling of equipment. Additionally, the EPA/NETL VOM cost of $1.8/MWh (2011$) is substantially less than the $3.27/MWh (2012$) EIA is currently using.[335]

There is also an unfair bias against new supercritical coal within the LCOE calculations based on the assumed operation and maintenance costs. The values used by EPA from NETL for FOM and VOM of $70.6/kW-yr and $7.70/MWh (2011$) respectively are significantly higher than the $31.18/kW-yr and $4.47/MWh (2012$)[336] being used by EIA. This further skews the comparison of natural gas versus conventional coal.

The LCOE also assumes an 85% capacity factor for all technologies being analyzed. This is factually disconnected with how new generation types will operate. Within the U.S., generators typically dispatch on variable cost, with lower cost sources dispatching more frequently. Over the long run, coal generation will dispatch more frequently than gas generation due to fuel costs approximately 50% less (on a MWh basis) than natural gas, as presented in LCOE analysis. Thus, EPA and EIA's assumption that new coal units and new natural gas units will have the same operation and capacity factors is incorrect. NGCC will not run at 85% of their capacity over the course of a year. Even with the historically low natural gas prices of 2012 and 2013, AEP's combined cycles ran substantially less. EPA should revise the levelized cost calculations to include more reasonable assumptions for natural gas plant operation. Results from broader electric sector modeling could be used to provide the appropriate basis for this

[335] http://www.eia.gov/forecasts/aeo/assumptions/pdf/table8_2_2014er.pdf
[336] Id.

number. The misrepresentation of the capacity factor results in vast underestimation of the fixed capital charges needed to be recovered from a NGCC unit per MWh of operation and incorrectly skews the cost downward.

Based on the aforementioned errors, the differences in levelized cost between NGCC and SCPC units is dramatically overstated and is particularly compounded by the use of a Climate Uncertainty Adder (CUA) within several of the comparisons, as discussed later in the comments. Therefore, EPA's statement that "it is only when natural gas prices reach $10.94/MMBtu on a levelized basis (in 2011 dollars) that new coal-fired generation without CCS becomes competitive in terms of its cost of electricity"[337] is patently false. Underestimation of NGCC capital and operational costs, overstatement of NGCC operational hours, and overstated operational costs for new coal units make the breakeven number significantly lower. This is demonstrated by the EIA analysis, which identifies new coal as being built in various sensitivity cases; even though EPA states that "none of the EPA sensitivities or AEO2013 scenarios approach this natural gas price level on either a forward looking 20-year levelized price basis or on an average annual price basis at any point during the analysis period."[338] These new coal builds occur within the model due to more accurate input data being used and the model correctly calculating the effect cost of new generation based on actual operation.

The RIA also assumes the levelized cost of coal with CCS are similar to nuclear power to determine that they represent similar options for non-natural gas low-carbon baseload power. As discussed above in comments on the cost evaluation performed for the BSER analysis, significant concerns exist regarding accuracy and representativeness of the CCS related cost estimates. For example, with the relatively high operating cost of a coal unit with carbon capture these types of units should not be modeled as baseload units with an 85% capacity factor. Adjusting for this factor alone, coal with CCS is likely to be much more expensive than new nuclear. Therefore, any position that the proposed emission limitation is justified from a cost comparison basis with nuclear is erroneous.

---

[337] RIA at 5-48
[338] Id.

C. IPM Modeling

EPA made several critical errors in the development of the IPM model and the runs used in support of the cost analysis. One major flaw in the IPM model is the double counting of CO_2 risk exposure. As stated in the RIA on page 5-15, "*both EIA and EPA include a capital charge rate adder (3 percent) for new conventional coal-fired generating capacity without CCS, which reflects the additional cost of raising capital that is currently reflected in the marketplace, related at least in part to uncertainty surrounding future greenhouse gas emission reduction requirements.*" Because this proposed NSPS removes much of the uncertainty regarding GHG emission reduction requirements by setting a standard, this penalty should be reduced or removed altogether in the modeling of the reference case for comparison purposes. The use of this penalty in the reference case is an inappropriate bias against new coal generation.

The IPM model also uses outdated capital cost inputs associated with new generation sources. EPA estimates that new NGCC will cost $976/kW in 2007 dollars.[339] This is substantially lower than estimates by the Electric Power Research Institute (EPRI) of $1275–1375/kW in 2010 dollars.[340] Even correcting for inflation, EPA's capital cost is ~20 to 25% lower than EPRI's estimate. Conversely, EPA projects that a new pulverized coal plant will cost $2,918 – $3,008/kW, in comparison to EPRI's cost of $2,400 – $2,760/kW. In this case, EPA's cost of new coal generation is ~15 to 30% higher than EPRI's estimates. In both cases, these flawed cost estimates artificially bias the model to new gas generation in lieu of coal generation by overstating the cost of coal capacity and understating the cost of gas capacity. This discrepancy should be corrected within IPM going forward.

D. Benefit Analysis

It is arbitrary for EPA to propose a rule with no substantive quantifiable benefits. As stated on page 1-4 of the RIA, "*EPA anticipates that the proposed EGU New Source GHG Standards will result in negligible CO_2 emission changes, energy impacts, quantified benefits, costs, and economic impacts.*"

EPA ineffectively tries to qualitatively describe potential tangential benefits that "*may*" occur, such as reducing regulatory uncertainty. However, this proposal will create even *greater*

[339] www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter4.pdf
[340] EPRI, Program on Technology Innovation: Integrated Generation Technology Options - Technical Update (June 2011).

uncertainty because of its novel treatment of existing modified and reconstructed sources. As an example, EPA is relying on its purported authority to promulgate a "new source" standard that does not apply to "modified" units (notwithstanding the controlling definition of "new source" in Section 111(a)(2) of the CAA) during a period when other EPA regulatory initiatives will require existing coal plants to undertake physical and operational changes in order to achieve reductions in criteria pollutant emissions that are known to increase the hourly rate of CO_2 emissions from coal-fired steam generators. EPA claims that such sources will be protected by the "pollution control project" exclusion in 40 CFR § 60.14(e)(5). EPA acknowledges that this exclusion (dating to 1975 in the NSPS program) is similar to a provision subsequently promulgated under the new source review regulations in Part 51, and that the D.C. Circuit Court's decision in *New York v. EPA*, 413 F.3d 3, 40 (D.C. Cir. 2005), invalidated that similar provision in the new source review program. The questionable continuing validity of the pollution control exclusion may well force additional coal unit retirements, beyond the 38,000 MW already announced, even though EPA has acknowledged that it has insufficient information to develop standards that could apply to existing sources.

Even if a source were willing to undertake such a risk and accept that installation of additional criteria pollutant controls would eventually require the capture and storage or sequestration of CO_2, uncertainty persists regarding the availability of adequate sequestration sites within reach of existing units, the actual performance of available capture technologies, the actual performance of long term sequestration operations, and the long-term regulatory framework for liability. EPA touts the use of DOE funding for CCS projects. However, the DOE has repeatedly pulled funding from its FutureGen project. DOE funding alone has been insufficient to allow half of the award recipients to continue with planned projects and depends upon an appropriation system that is subject to the federal budgeting process.

EPA also presents calculations using a benefit per ton reduced for NO_x and SO_2 that suffer from additional flaws. National Ambient Air Quality Standards are designed to protect the human and ecological health with an adequate margin of safety. Additional reductions of these pollutants well below these standard levels should not have **any** quantifiable health benefit. Additionally, the modeling and calculations presented by EPA ignore the projected impacts of the MATS Rule on air quality, which in many cases will drive emissions below the Lowest Measured Levels in the studies used to support the health claims, thus invalidating the

applicability of the studies to a benefit calculation. Furthermore, the Krewski et al. and Lepeule et al. studies which underpin the health benefit calculations that EPA estimates[341] use data from the 1980s and 1990s that do not take into account current air quality emission levels or trends. For example, air emissions post-MATS implementation are going to be significantly lower than the years used in these studies. Additionally, these studies fail to differentiate health response between various components of particulate matter even though more recent studies show associations between locally produced carbonaceous compounds but *NO* associations between utility produced SO_2 and NO_x emissions.[342] There is also concern with EPA's continued use of the Value of a Statistical Life calculated from willingness to pay survey results as these results do not appropriately value premature mortality that could be measured in days. A more robust measure needs to be developed that appropriately values premature mortality with consideration to temporality.

Given the acknowledged limitations of the analyses presented, EPA should not include any discussion of health benefits within the RIA as any such benefits are indirect and speculative. Furthermore, EPA should update its calculations of health benefits to include use of a broader range of scientific literature, including peer-reviewed studies showing no association with PM and mortality and significant issues with health benefit calculation methodologies.[343]

E. Social Cost of Carbon

EPA uses the Social Cost of Carbon (SCC) to characterize potential carbon benefits associated with the rule, with even though it is widely acknowledged that these cost estimates are inaccurate, uncertain, and highly speculative. [344] EPA acknowledges in the RIA that "*any effort to quantify and monetize the harms associated with climate change will raise serious questions of science, economics, and ethics and should be viewed as provisional.*" As such, these

[341] (see, e.g., RIA at 5-42)
[342] Examples include: (1) Grahame TJ. 2009. Does improved exposure information for PM2.5 constituents explain differing results among epidemiological studies? Inhal .Toxicol. 21: 381-393; (2) Lipfert FW, Wyzga RE, Baty JD, Miller JP. 2009. Air pollution and survival within the Washington University-EPRI veterans cohort: risks based on modeled estimates of ambient levels of hazardous and criteria air pollutants. J Air Waste Manag Assoc. 2009 Apr;59(4):473-89; and (3) Grahame T, and Hidy GM. 2007. Pinnacles and Pitfalls for Source Apportionment of Potential Health Effects From Airborne Particle Exposure. Inhal .Toxicol. 19: 727-744.
[343] Graven et al. An Approach to the Estimation of Chronic Air Pollution Effects Using Spatio-Temporal Information. Journal of the American Statistical Association. 2011
[344] (see RIA 5-36 through 5-39)

calculations cannot form the basis of an adequate RIA. AEP has submitted comments on the SCC in its development and use and they are attached as Appendix F to this document.

F. Climate Uncertainty Adder

Both EPA and EIA make use of a climate uncertainty adder (CUA) within integrated economic modeling and in presenting the LCOE for new electric generating options. The premise behind the CUA is to represent the fact that risks associated with future climate policy are likely to impact choices for new generation. While in practice the carbon policy risk does factor into planning decisions, the CUA is being improperly used. For example, many utilities use a carbon price in their planning decisions, however this price is typically back loaded within the planning period given policy uncertainty and the regulatory development period necessary for such a variable to have practical effect. Therefore, the 3% WACC adder as currently employed is artificially high.

Furthermore, within generation planning processes, carbon policy assumptions are typically applied across all fossil fuel choices and are coupled with a market response to energy pricing, if modeled within an integrated electric sector and/or economy-wide model. Therefore, inclusion of the CUA only with respect new coal does not provided the appropriate perspective or feedback on true carbon risk as it would suggest there is no carbon risk associated with other fossil fuels, namely natural gas.

Carbon risk should be accounted for outside of a LCOE comparison, and thus the CUA should not be included as part of LCOE. When modeling the electric sector as a whole, it may be appropriate to characterize carbon risk, but to provide a true "apples to apples" LCOE comparison, the CUA should never be included. A number of external factors play into generation investment decisions, which are also not "monetized" within the LCOE. Removing the CUA adder from the LCOE would dramatically reduce the breakeven natural gas price necessary to favor new coal. Any future analysis by either EPA or EIA should not use a CUA in evaluation of technology.

XII. Comments on the Structure of the Proposed NSPS

A. Adequacy of Proposed Fossil Fuel-fired Boiler and IGCC NSPS

As discussed previously, CCS clearly does not qualify as the BSER within the meaning of section 111(a) of the Clean Air Act. EPA requested comment on whether the proposed standard of 1,100 lb/MHh should more appropriately be set within the range of 1,000 to 1,200 lb/MWh.[345] These rates have not been proven to be technically feasible and have certainly not been adequately demonstrated for coal-based electric generation technologies. AEP recently completed construction of an ultra-supercritical unit, which is employing state-of-the-art advanced coal technology. Based on the subbituminous fuel used, the projections for load fluctuation and periodic unit startups, operations to date, and available information regarding equipment degradation over a units operational life, AEP estimates that an annual gross CO_2 emission rate of 1,900 lb/MWh would incent the development of more highly efficient generation technologies, while properly balancing the other factors (including costs) associated with the determination of the BSER.

B. Adequacy of Proposed Natural Gas Combustion Turbine NSPS

EPA requested comment on whether the proposed standard of 1,000 lb/MWh should more appropriately be set within the range of 950 and 1,100 lb/MWh for the large turbine subcategory.[346] There are a number of factors that result in variability of emissions that have not been adequately considered by EPA: operating at part load, use of backup fuel, startup and shutdowns, performance degradation, and other factors. Also, increased cycling of NGCC to support integration of variable renewable resources is expected, as well as higher capacity factors of new NGCC units. In light of all these factors and considering the lack of commercially available CO_2 control technologies for fossil-fired generation, it is recommended that a more appropriate standard for new, large NGCC units is 1,100 lb/MWh or more.

[345] 79 Fed. Reg. at 1470.
[346] Id. at 1437.

C. Applicability Requirements – Low Capacity Factor Stationary Turbines Should Be Clearly Exempted[347]

The original proposal explicitly did not apply to simple cycle turbines and AEP supports that exemption for simple cycle turbines instead of the current proposal. EPA's current proposal is that simple cycle turbines not be exempted if the facility supplies more than one-third of its potential electric output and more than 219,000 MWh net electric output to the grid per year. EPA requests comments on a range of 20 to 40 percent of potential electric output sales on a three-year basis for the capacity factor exemption. EPA also requests comment on whether applicability for stationary combustion turbines should be defined on a single calendar year basis, similar to the current subpart Da applicability for criteria pollutants, instead of a three-year basis. Notwithstanding our comment that simple cycle turbines should be clearly exempted as originally proposed, if EPA retains the applicability criteria approach, AEP supports a 40 percent of potential electric output sale for a capacity factor exemption measured as a three-year rolling average for the capacity factor exemption. Additionally, in the case where simple cycle turbines are constructed with the intent to operate prior to the future construction of a heat recovery steam generator (HRSG), such turbines should be exempted from the proposed rule under these same criteria until such time that construction of the HRSG and related equipment is completed and the unit commences operation in a combined cycle mode.

D. Before Establishing a Net-Output-Based Standard, EPA Must Conduct a Much More Detailed Technical Analysis

EPA requested comment on the use of net-output based standards either as a compliance alternative for, or in lieu of, gross-output based standards, including whether there should be a different approach for different subcategories.[348] In the NSPS for Subpart Da criteria emissions, EPA did not require a net output approach "[d]ue to the lack of net-output-based emission rates for multiple types of EGUs with various control configurations over a range of operating conditions."[349] EPA should be consistent in the use of gross-based output standards in this rulemaking. Generally, AEP supports the use of gross output-based standards, however, the use of gross-based generation results in a number of complex technical and operational considerations that can influence emission rates and unit efficiencies. These issues warrant a

[347] Id. at 1459.
[348] Id. at 1447.
[349] 73 Fed. Reg. 33,642 at 4.

much greater technical analysis, which further supports that finalization of these standards is premature and that the proposed rule should be changed to an advanced notice of proposed rulemaking so that the agency can fully evaluate the implications and design of gross-based output standards.

E. In Regard to Startup, Shutdown, and Malfunction Requirements; An Affirmative Defense Is Necessary at a Minimum, But Standards Should Not Apply During Startup and Shutdown Periods[350]

Units that operate at lower capacity factors than those associated with baseload operations will have more startups and shutdowns and thus increased CO_2 emissions. Not accounting for the lower capacity units and more frequent startups and shutdowns punishes NGCC for that operational flexibility. Instead of including these periods, EPA should provide for work practice standards to minimize emissions during startup and shutdowns. If that change isn't adopted, then the proposed NSPS standard should be raised as discussed in paragraph B above. AEP supports the affirmative defense as the minimum necessary to protect EGU rights. The affirmative defense to civil and penalties for violation of emission limits that are caused by malfunctions, should apply to both the 12-operating-month standard and the 84-operating-month rolling average compliance option.

XIII. Response to Miscellaneous EPA Requests for Comment

A. AEP Supports an Exemption for the Coal Refuse Subcategory

EPA solicits comments on establishing a subcategory for coal refuse-fired EGUs.[351] AEP supports a subcategory that would exempt such units from the proposed NSPS requirements due to the environmental benefits of remediating coal refuse piles. Further, AEP supports additional fuel-specific subcategorization that establishes a coal-specific standard *that reflects the best demonstrated performance of existing advanced coal technologies.*

B. Emergency Conditions – AEP Agrees that Net Sales During Emergencies Should Not Be Counted When Determining Applicability

EPA requests comment on excluding electricity generated as a result of a grid emergency declared by the RTO, ISO or control area Administrator as counting as net sales when

[350] 79 Fed. Reg. 1448 – 1450.
[351] Id. at 1496.

determining applicability as an EGU.[352] AEP supports the position that emergency conditions do occur and may require that all available operable EGUs interconnected to the electrical grid supply power to the grid.

C. AEP Supports the Exclusion of Non-CO_2 GHG Emissions from the Rule

EPA requests comments on the appropriateness, technique, and frequency of measurement of and reporting of CH_4 and N_2O emission from fossil fuel-fired EGUs as part of the proposed emissions standard. AEP supports EPA's proposal to not include these other GHGs because their emissions from EGUs are negligible when compared to CO_2. Because existing EGUs have been calculating and reporting N_2O and CH_4 emissions under the GHG Reporting Rule since 2011, using emissions factors, additional measurement and reporting is not justified.

D. AEP Supports EPA's Proposal to Not "Double Count" Rolling Violations When Additional Violations Occur Directly Following a 12-operating Month or 84-operating Month Averaging Period[353]

EPA proposes that the calculation of the number of daily violations within an averaging period be determined such that if a violation occurs directly following the previous 12-operating-month or 84-operating-month averaging period (during which the emission rate exceeds the standard), daily violations would not double count operating days that were determined as violations under the previous averaging period. AEP objects to the automatic imposition of penalties for exceedances without some exercise of discretion. There may be valid reasons, such as sustained periods of extremely cold weather that would support the need for exercise of enforcement discretion in cases of small exceedances of the CO_2 standards. These objections aside, AEP agrees that violations should not be "double counted."

[352] Id. at 1497.
[353] Id. at 1498.

Appendix A

Analysis of CCS Projects Referenced by EPA in the Proposed Rule

Appendix A: Analysis of CCS Projects Referenced by EPA in the Proposed Rule

EPA Referenced CCS "development" or "demonstration" Projects

EPA Reference	Unit Type[354]	CCS[355]	Project Status[356]	Comments
Kemper (Southern Co)	IGCC 582 MW (net)[357]	3,000,000 tonnes/yr EOR Amine-based capture	Under Construction Startup late 2014[358]	▪ Final Air Permit = No CO_2 Limits[359] ▪ PSC Certificate = No CO_2 Limits[360] ▪ EIS Mitigation Action Plan[361] ➢ "The purpose of DOE's action....is to demonstrate the feasibility of this selected IGCC technology at a size that would be attractive to utilities for commercial operation." (p. 3) ➢ Demonstration period = 54 months (p. 4) ➢ "Use best efforts to achieve 67% carbon capture during the demonstration period" (p. 7)
SaskPower BoundaryD am[362] (Canada)	PC (rebuild) 160 MWg 110 MWn[363]	1,000,000 tonnes/yr EOR	Construction Startup 2014	▪ FOAK – Integrated CCS

[354] Unless noted CCS data from: Ackiewicz, M. (Jan. 23, 2014) "Update on Status and Progress in the DOE CCS Program." U.S. DOE. 2014 UIC Conference. New Orleans, LA. www.gwpc.org/sites/default/files/event-sessions/Ackiewicz_Mark.pdf
[355] Unless noted CCS data from: Ackiewicz
[356] Unless noted Project Status from: Ackiewicz.
[357] Kemper County IGCC Project. Mitigation Action Plan. (DOE/EIS-0409). U.S. Department of Energy. September 2010. p. 4
[358] Kemper County IGCC Fact Sheet. MIT. https://sequestration.mit.edu/tools/projects/kemper.html (accessed February 24, 2014)
[359] Air Permit #1380-00017 (October 24, 2012). Mississippi Department of Environmental Quality.
[360] Mississippi Public Service Commission Order. RE: CPCN Petition from Mississippi Power Company. Docket 2009-UA-14. May 26, 2010.
[361] Kemper County IGCC Project. Mitigation Action Plan. (DOE/EIS-0409). U.S. Department of Energy. September 2010. p.
[362] Unless noted, all data for Boundary Dam project from: www.saskpowerccsconsortium.com/ccs-projects/saskpower-initiatives/carbon-capture-project/
[363] Boundary Dam CCS Project Fact Sheet. MIT. https://sequestration.mit.edu/tools/projects/boundary_dam.html (accessed February 24, 2014)

Appendix A: Analysis of CCS Projects Referenced by EPA in the Proposed Rule

EPA Referenced CCS "development" or "demonstration" Projects

EPA Reference	Unit Type[364]	CCS[365]	Project Status[366]	Comments

Texas Clean Energy Project (Summit)	IGCC (polygen) 400 MWg 130-212 MWn[367] (low net due to polygen design)	2,200,000 tonnes/yr EOR Rectisol Capture[368]	Securing Financing No Construction Startup 2017	▪ Power Purchase Agreement with CPS Energy expired Dec 31, 2013[369]
				▪ Latest update on project website was September 16, 2012.[370]
				▪ Final Air Permit = No CO_2 Limits[371]
				▪ No evidence that Class VI UIC permit has been obtained[372]
				▪ EIS Record of Decision[373]
				  ▪ "DOE's purpose...is to demonstration the commercial-readiness of CO_2 capture and geologic sequestration fully integrated with a power plant"
				  ▪ Demonstration period = startup until July 15, 2017 (p. 60479)
				  ▪ "use best efforts to achieve at least a 90 percent capture rate during the demonstration period" (p. 60480)

Hydrogen Energy California	IGCC (polygen) 405-431 MWg 151-266 MWn[374] (low net due to polygen design)	2,570,000 tonnes/yr EOR	FEED Ongoing No Construction Startup ~ 2019	▪ EIS has not been finalized ▪ California Energy Commission Certificate has not issued ▪ When considering ASU and EOR related power, net output = 52.5 MW ▪ At maximum fertilizer production, plant is a net consumer from grid = 61.8MW[375] ▪ Final Air Permit = Limits operation if EOR operator is out of service[376] ▪ Agreement has not be finalized with EOR Operator ▪ Class VI UIC permit has not been obtained

[364] Unless noted CCS data from: Ackiewicz, M. (Jan. 23, 2014) "Update on Status and Progress in the DOE CCS Program." U.S. DOE. 2014 UIC Conference. New Orleans, LA. www.gwpc.org/sites/default/files/event-sessions/Ackiewicz_Mark.pdf
[365] Unless noted CCS data from: Ackiewicz
[366] Unless noted Project Status from: Ackiewicz.
[367] 76 Fed. Reg. 60478 (Sept 29, 2011). EIS Record of Decision, Texas Clean Energy Project.
[368] www.netl.doe.gov/publications/proceedings/11/co2capture/presentations/4-Thursday/25Aug11-Kirksey-Summit-Carbon%20Capture%20using%20Rectisol.pdf
[369] http://newsroom.cpsenergy.com/blog/traditional-fuels/coal-traditional-fuels/cps-energys-ppa-texas-clean-energy-project-expired-dec-31/ (accessed Feb 24, 2014)
[370] www.texascleanenergyproject.com/news-room/ (accessed Feb 24, 2014)
[371] Air Permit #92350 and PSDTX1218 (2010). Texas Commission on Environmental Quality
[372] Based on a review of project and agency websites
[373] 76 Fed. Reg (Sept 29, 2011). EIS Record of Decision, Texas Clean Energy Project.
[374] HECA Preliminary Staff Assessment, Draft EIS. p.1-7. June 2013. http://energy.gov/sites/prod/files/2013/07/f2/EIS-0431-DEIS-2013v2.pdf
[375] HECA Preliminary Staff Assessment, Draft EIS. p.1-7. June 2013. http://energy.gov/sites/prod/files/2013/07/f2/EIS-0431-DEIS-2013v2.pdf
[376] Final Air Permit. (2013). San Joaquin Valley APCD.

Appendix A: Analysis of CCS Projects Referenced by EPA in the Proposed Rule

EPA Referenced CCS "development" or "demonstration" Projects

EPA Reference	Unit Type[377]	CCS[378]	Project Status[379]	Comments
W.A. Parish (NRG Energy)	PC (retrofit) Capture from 250MWe[380]	1,400,000 tonnes/yr EOR	Securing Financing Startup 2016	▪ Air Permit = No CO_2 Limits[381] ▪ EIS Record of Decision[382] ➢ "DOE's [purpose is]...to demonstrate the feasibility of advanced coal-based technologies at a commercial-scale that capture and geologically sequester CO2 emissions." (p. 30902) ➢ "The data would be used to help DOE evaluate whether the deployed technologies could be effectively and economically implemented at a commercial scale" (Id) ➢ "use best efforts to achieve at least 90 percent capture during the demonstration period" (p. 30905) ▪ 35 month demonstration project for EIS requirements[383] ▪ No evidence that Class VI UIC permit has been obtained[384]
FutureGen 2.0 (Illinois)	PC oxy-combustion (retrofit) 168 MWg[385]	1,000,000 tonnes/yr Geologic Storage	FEED Ongoing No Construction Startup ~ 2017	▪ No air permit has been issued. Unclear if application has been filed ▪ Negotiations not finalized to purchase parts of existing unit[386] ▪ Class VI UIC permits has not been issued.[387] ▪ EIS Record of Decision[388] ▪ "DOE's [purpose is]...to demonstrate the commercial feasibility of an advanced coal-based technology (oxy-combustion) that may serve as a cost-effective approach to implementing carbon capture at new and existing power plants." (p. 3578)

[377] Unless noted CCS data from: Ackiewicz, M. (Jan. 23, 2014) "Update on Status and Progress in the DOE CCS Program." U.S. DOE. 2014 UIC Conference. New Orleans, LA. www.gwpc.org/sites/default/files/event-sessions/Ackiewicz_Mark.pdf
[378] Unless noted CCS data from: Ackiewicz
[379] Unless noted Project Status from: Ackiewicz.
[380] Final EIS Summary: W.A. Parish Post-Combustion CCS Project (DOE/EIS-0473). U.S. Department of Energy. February 2013. p. 3
[381] Review of Related Air Permits. Texas Commission on Environmental Quality. (https://webmail.tecq.state.tx.us accessed Feb 24, 2014)
[382] 78 Fed. Reg (Sept 23, 2013). EIS Record of Decision, W.A. Parish Post-Combustion CCS Project.
[383] Final EIS Summary: W.A. Parish Post-Combustion CCS Project (DOE/EIS-0473). U.S. Department of Energy. February 2013. p.3
[384] Based on a review of project and agency websites
[385] 79 Fed. Reg 3578. (January 22, 2014). EIS Record of Decision, FutureGen 2.0 Project
[386] "FutureGen: A Brief History and Issues for Congress." Folger, P. (February 10, 2014). Congressional Research Service. R43028. p. 3
[387] www.epa.gov/r5water/uic/index.htm
[388] 79 Fed. Reg (January 22, 2014). EIS Record of Decision, FutureGen 2.0 Project.

Appendix A: Analysis of CCS Projects Referenced by EPA in the Proposed Rule

EPA Referenced CCS "development" or "demonstration" Projects

EPA Reference in Proposed Rule	Comments
Mountaineer CCS Program (AEP)	▪ Validation-scale (1.5% slip stream) project completed 2009-2011 ▪ Not an integrated commercial scale electric generation CCS project ▪ See Section VIII.A. of AEP comments for more information ▪ Air permit has no CO_2 limits
Plant Berry CCS Program[389] (Southern Company)	▪ Validation-scale (25MWe) CCS project ▪ Air permit has no CO_2 limits ▪ Not an integrated commercial scale electric generation CCS project
AES Warrior Run (Maryland)	▪ "Warrior Run...has been capturing a small portion of its CO_2 emissions for use in the food and beverage industry since 2000.... [T]hese existing capture technologies are energy-intensive, making their application to coal-fired power plants and other industrial sources potentially costly. Scaling these existing processes up to a commercial level and integrating them with fossil fuel-based power generation currently poses technical, economic, and regulatory challenges."[390] ▪ Air permit has no CO_2 limits ▪ Not an integrated commercial scale electric generation CCS project
AES Shady Point (Oklahoma)[391]	▪ CO_2 capture from a "small slip stream" to supply food industry ▪ Air permit has no CO_2 limits ▪ Not an integrated commercial scale electric generation CCS project
Searles Valley Minerals Soda Ash[392]	▪ Not an integrated commercial scale electric generation CCS project
Vattenfall Plant (Germany)	▪ 10 MWe oxy-combustion demonstration ▪ Not an integrated commercial scale electric generation CCS project
Captain Clean Energy Plant (Summit Power) /(Scotland)[393]	▪ Proposed integrated coal-based generation/CCS project ▪ Currently only a conceptual project, at best
"another poly-generation plant" (Summit Power)	▪ EPA references a news article quoting Summit Power as saying it "will also plan on announcing its second poly-generation IGCC capture project... following TCEP's financial close"[394] ▪ Currently only a conceptual project, at best
"one NGCC unit" with CCS	▪ Not an integrated commercial scale electric generation CCS project ▪ See Section VIII.E. of AEP comments for more information
Global CCS Institute Database of CCS Projects	▪ 60 Power Generation CCS projects listed: Only 2 are actively being constructed (Boundary Dam and Kemper); The balance are planned[395]
DOE/NETL CCUS Database[396]	▪ Does not list any noteworthy CCS efforts beyond those specifically identified in the proposed rule. Much of the data appears dated.

[389] Data from https://sequestration.mit.edu/tools/projects/plant_barry.html
[390] "Summary of Potential Carbon Capture, Use, and Storage (CCUS) Options for the State of Maryland." Maryland Department of Natural Resources. (May 2013) p. ES-1 to ES-2.
[391] Data from "As Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009." Dooley, et.al. Pacific Northwest National Laboratory. PNNL-18520. p. 9
[392] Data from "As Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009." Dooley, et.al. Pacific Northwest National Laboratory. PNNL-18520. p. 9
[393] Data from http://sequestration.mit.edu/tools/projects/captain.html
[394] http://ghgnews.com/index.cfm/summit-even-without-uk-demo-funding-project-will-move-forward/?mobileFormat=true
[395] www.globalccsinstitute.com/projects/browse (accessed February 24, 2014)
[396] http://www.netl.doe.gov/technologies/carbon_seq/global/database/

Appendix A: Analysis of CCS Projects Referenced by EPA in the Proposed Rule

Other EPA Referenced CCS-related "development" or "demonstration" Projects:

EPA Reference in Proposed Rule	Comments
Great Plains Synfuels Facility (Dakota Gasification Company) (North Dakota)[397]	▪ Coal gasification plant that produces natural gas and other products ▪ Supplies CO_2 to Weyburn and Midale EOR ▪ Not an integrated commercial scale electric generation CCS project
Weyburn EOR Project (Canada)[398]	▪ CO_2 geologic storage began in 2000 ▪ 1,000,000 tonnes/yr CO_2 stored ▪ Concerns have been raised regarding CO_2 leakage from storage site ▪ Not an integrated electric generation CCS project
Sleipner (North Sea - Norway)[399]	▪ CO_2 geologic storage began in 1996 ▪ 1,000,000 tonnes/yr CO_2 stored ▪ CO_2 produced by natural gas processing unit ▪ CO_2 capture and storage project to avoid Norwegian CO_2 tax ▪ Not an integrated electric generation CCS project
Snohvit (Barents Sea - Norway)	▪ CO_2 geologic storage began in 2008 ▪ 700,000 tonnes/yr CO_2 stored ▪ CO_2 produced by natural gas processing unit ▪ Not an integrated electric generation CCS project
In Salah[400] (Algeria)	▪ CO_2 geologic storage began in 2004; Suspended in 2011 due to concerns regarding the integrity of the seal ▪ 1,200,000 tonnes/yr CO_2 stored ▪ CO_2 produced by natural gas processing unit ▪ Not an integrated electric generation CCS project
SACROC[401] (Texsa)	▪ Injection of primarily of anthropogenic CO_2 since 1972 for EOR ▪ Recycling of some CO_2 for additional EOR ▪ Not an integrated electric generation CCS project
Gorgon CO_2 Injection Project (Australia)[402]	▪ Project under construction; Startup estimated in 2015 ▪ 4,100,000 tonnes/yr CO_2 stored from natural gas processing plant ▪ Not an integrated electric generation CCS project
Collie-South West CO_2 Geosequestration Hub (Australia)	▪ Potential project to geological store CO_2 from multiple sources ▪ Design work continues; No estimate for when/if project will start ▪ Not an integrated electric generation CCS project

[397] Data from www.dakotagas.com/About_Us/index.html
[398] Data from http://sequestration.mit.edu/tools/projects/weyburn.html
[399] Data from https://sequestration.mit.edu/tools/projects/sleipner.html
[400] Data from https://sequestration.mit.edu/tools/projects/in_salah.html
[401] "An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009." Dooley, et.al. Pacific Northwest National Laboratory. PNNL-18500. pp. 15
[402] Data from http://sequestration.mit.edu/tools/projects/gorgon.html

Appendix B

Examples of Major Public and Private Assessments of CCS Development

Appendix B – Examples of Major Public and Private Assessments of CCS Development

Report/Organization	Date	State of CCS	Barriers to Commercially Acceptable CCS	Prospects for CCS Development
President Obama's Interagency Task Force on Carbon Capture and Storage. Report of the Interagency Task Force[403]	Aug. 2010	"Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation because they have not been demonstrated at the scale necessary to establish confidence for power plant application." (p.50) "CCS technologies...are not likely to be widely deployed at coal-fired power plants....without additional knowledge generated by research, development, and demonstration activities." (p.87)	"Though CCS technologies exist, "scaling up" these existing processes and integrating them with coal-based power generation poses technical, economic, and regulatory challenges." (p.9) "..barriers hamper near-term and long-term demonstration and deployment of CCS technology." (p.14) "A concerted effort to properly address financial, economic, technological, legal, institutional, and social barriers will enable CCS to be a viable climate change mitigation option..." (p.8)	"Administration analyses of proposed climate change legislation suggest that CCS technologies will not be widely deployed in the next two decades..." (p.8) "The focus of CCS RD&D is....to facilitate widespread cost-effective deployment after 2020." (p.9)
The National Coal Council (a Federal Advisory Committee to Secretary of Energy Chu). *Expedited CCS Development: Challenges & Opportunities*[404]	Mar. 2011	"..a range of issues must be addressed before CCS processes are commercially acceptable for coal-based electric generating units. ...key development concerns include the fact that commercial-scale CCS processes have *not yet* been demonstrated on a coal-fired generating unit" (p.1)	"...the current CCS demonstration program in the [U.S.]...is not on pace to significantly advance CCS development in the near-term due to technical and equally non-technical obstacles.... Challenges to CCS development...can be broadly categorized into technical, financial, and regulatory areas." (p.1)	"At the current [development] rate, CCS technologies will continue to be in an early development stage by 2020." (p.64) "Ongoing and planned CCS projects for coal-based generation are advancing the development of the technology, but not at the pace necessary to support an expedited and broad-based deployment of CCS by 2050." (p.14)
DOE / NETL Advanced Carbon Dioxide Capture R&D Program: Technology Update[405]	May 2011	"...in their current state of development [the CO_2 capture technologies being used in industrial applications] are not ready for implementation on coal-based power plants" (p.4)	"[CO_2 capture] technologies are not ready for implementation on coal-based power plants [because] (1) they have not been demonstrated at the larger scale necessary for power plant application; (2) the parasitic loads (steam and power) required to support CO_2 capture would decrease power generating capacity...; and (3) if successfully scaled-up, they would not be cost effective at their current level of process development." (p.4)	"It is anticipated that successful progression from laboratory- to full-scale demonstration will result in several of these [CO_2 capture] technologies being available for commercial deployment by 2030." (p.10)
DOE / NETL CO_2 Capture and Storage RD&D Roadmap[406]	Dec. 2010	"...cost-effective and efficient CCS technologies will need to be developed and demonstrated at full-scale prior to their availability for widespread commercial deployment." p. 5 "...at their current state of development these [CO_2 capture] technologies are not ready for implementation on coal-based power plants." (p.21)	"...advanced technologies developed in the CCS RD&D effort need to be tested at full scale in an integrated facility before they are ready for commercial deployment." (p.11)	"....the overall timeline for RD&D....involves pursuing advanced CCS technology from the fundamental / applied stage through pilot-scale so that full-scale demonstrations can begin by 2020. The RD&D effort will produce the data and knowledge needed to establish the technology base, reduce implementation risks by industry, and enable broader commercial deployment of CCS to begin by 2030." (p.10)
DOE / NETL Carbon Sequestration Program: Technology Program Plan[407]	Feb. 2011	"The overall objective of the Carbon Sequestration Program is to develop and advance CCS technologies that will be ready for widespread commercial deployment by 2020." (p. 10)	"To accomplish widespread [commercial] deployment [of CCS by 2020], four program goals have been established: (1) [reduce CCS related costs]; (2) [improve the] ability to predict CO_2 [geologic] storage capacity; (3) develop technologies to demonstrate that...CO_2 remains in the injection zones; (4) complete Best Practices Manuals...for site selection, characterization, site operations, and closure practices." (p. 10)	"Only by accomplishing these goals [of the DOE Carbon Sequestration Program] will CCS technologies be ready for safe, effective commercial deployment both domestically and abroad beginning in 2020 and through the next several decades." (p.10)

[403] "Report of the Interagency Task Force on Carbon Capture and Storage." Aug 2010. www.fe.doe.gov/programs/sequestration/ccs_task_force.html
[404] "Expediting CCS Development: Challenges and Opportunities." Mar 2011. Library of Congress Catalog #2011926623. www.nationalcoalcouncil.org
[405] Department of Energy / National Energy Technology Lab. May 2011. www.netl.doe.gov/technologies/coalpower/ewr/pubs/CO2Handbook/
[406] Department of Energy / National Energy Technology Lab. Dec 2010. www.netl.doe.gov/technologies/carbon_seq/refshelf/CCSRoadmap.pdf
[407] Department of Energy / National Energy Technology Lab. Feb 2011. www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf

Appendix B - Examples of Major Public and Private Assessments of CCS Development

Report/Organization	Date	State of CCS	Barriers to Commercially Acceptable CCS	Prospects for CCS Development
2014 DOE/NETL Carbon Capture website[408]	Accessed April 2014	"Commercially available first-generation CO_2 capture technologies are currently being used in various industrial applications. However, in their current state of development, these technologies are not ready for implementation on coal-based power plants..." (home page of website)	"[Commercial-scale CCS technologies for coal-based power plants]...have not been demonstrated at appropriate scale, require approximately one-third of the plant's steam and power to operate, and are cost prohibitive." (home page of website)	"The success of...[current R&D efforts] in developing these technologies will enable cost-effective implementation of carbon capture and storage (CCS) throughout the power-generation sector..." (home page of website)
"Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy" Congressional Research Service[409]	Feb 2014	"To date...there are no commercial ventures....that capture, transport, and inject industrial-scale quantities of CO_2 solely for the purposes of carbon sequestration" (summary page)	"The challenge of reducing the costs of CCS technology is difficult to quantify, in part because there are no examples of currently operating commercial-scale coal-fired power plants equipped with CCS. Nor is it easy to predict when lower-cost CCS technology will be available for widespread deployment in the United States." (p. 6) "Development Phase projects will provide a better understanding of regulatory, liability, and ownership issues associate with commercial scale CCS. These nontechnical issues are not trivial, and could pose serious challenges to widespread deployment of CCS even if the technical challenges of injecting CO_2 safely and in perpetuity are resolved." (p. 23)	"..the coal RD&D program is focused on achieving results that would allow for an advanced CCS technology portfolio to be ready by 2020 for large-scale demonstration." (pp 6-7)
"A Summary of Potential Carbon Capture, Use, and Storage Options for the State of Maryland" Maryland Department of Natural Resources[410]	May 2013	"CCUS is not fully developed to a commercially available scale" (p. 1-1) "Current and emerging technologies may be considered to capture CO_2 from new and existing fossil energy power plants.... However, these technologies have not been demonstrated at the scale necessary to establish confidence for widespread power plant application." (p. 3-7)	"Scaling these existing [carbon capture] processes up to a commercial level and integrating them with fossil-fuel power generation currently poses technical, economic, and regulatory challenges" (ES-2) "..because CCUS has not been widely deployed, there is uncertainty about how environmental statutes will apply...and if the current framework is adequate for both near- and long-term deployment of CCUS." (p. 2-7) "developing a transportation infrastructure to accommodate future CCUS projects may encounter challenges regarding technology, cost, regulation, policy, right-of-way, and public acceptance." (p. 4-1)	"Carbon capture technologies necessitate additional research, development, and demonstration to reach commercial scale" (p 6-1)
"Opportunities Exist for DOE to Provide Better Information on the Maturity of Key Technologies to Reduce Carbon Dioxide Emissions"[411] U.S. Government Accountability Office	June 2010	"while components of CCS have been used commercially in other industries, their application remains at a small scale in coal power plants" (p. 2)	"Use of [CCS] is...contingent on overcoming a variety of economic, technical and legal challenges. In particular, with respect to CCS, stakeholders highlighted the large costs to install and operate current CCS technologies, the fact that large scale demonstration of CCS is needed in coal plants, and the lack of...a legal framework to govern liability for permanent storage of large amounts of CO_2" (p. 2)	"Commercial deployment of CCS is possible within 10 to 15 years" (p. 2)
"Carbon Capture: A Technology Assessment" Congressional Research Service[412]	Nov 2013	"at present there are still no full-scale applications of CO_2 capture on a coal-fired or gas-fired power plant" (p.2)	"the major drawbacks of current [CO_2 capture] processes are their high cost and the large energy requirements for operation." (p. 2)	"Technology roadmaps developed by governmental and private-sector organizations...anticipate that CO_2 capture will be available for commercial deployment at power plants by 2020.... Such projections acknowledge, however, that this will require aggressive and sustained efforts to advance promising concepts to commercial reality." (p. 2)

[408] www.netl.doe.gov/research/coal/carbon-capture
[409] "Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy" Feb 10, 2014. Folger, P. Congressional Research Service.
[410] "A Summary of Potential Carbon Capture, Use, and Storage Options for the State of Maryland." May 2013. Power Plant Research Program. Maryland DNR. DNR Publication No. 12-5162013-645.
[411] www.gao.gov/products/GAO-10-675
[412] "Carbon Capture: A Technology Assessment" (Nov 2013). R41325. Congressional Research Service. www.fas.org/sgp/crs/misc/R41325.pdf

Appendix C

CCS Lessons Learned Report AEP Mountaineer CCS II Project Phase 1

CCS LESSONS LEARNED REPORT
American Electric Power
Mountaineer CCS II Project
Phase 1

Prepared for

The Global CCS Institute

Project # PRO 004

January 23, 2012

Guy L Cerimele, PE, PMP
American Electric Power Service Corporation
1 Riverside Plaza
Columbus, Ohio 43215

Copyright © 2012 American Electric Power Inc. All Rights Reserved

ACKNOWLEDGEMENT

This material is based upon work supported by the US Department of Energy Award Number DE-FE0002673.

The Author would like to thank all who contributed to this report, both directly and indirectly (via incorporation of select content from various work products). The integrated project team involving AEP, Alstom, Battelle and WorleyParsons personnel successfully melded together to form a cohesive project team to deliver on the Phase I requirements of the Department of Energy Cooperative Agreement. The good work of the project team is attributable to many individuals, too numerous to mention herein. The open communications and rapport developed by the team during Phase I is reflected in the many inputs/suggestions of lessons learned, process improvements and exemplary practices that were documented and complied at the end of Phase I- Project Definition Phase.

Copyright © 2012 American Electric Power Inc. All Rights Reserved

DISCLAIMERS

US Department of Energy: This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

American Electric Power: This report is provided "as-is" and with no warranties, express or implied, whatsoever for the use or the accuracy of the information contained therein. Use of the report and the information found therein is at the sole risk of the recipient. American Electric Power Company, its affiliates and subsidiaries, shall not be liable in any way for the accuracy of any information contained in the report, including but not limited to, any errors or omissions in any information content; or for any loss or damage of any kind incurred as the result of the use of any of the information.

Copyright © 2012 American Electric Power Inc. All Rights Reserved

TABLE OF CONTENTS

1. SYNOPSIS 1
2. EXECUTIVE SUMMARY 1
3. INTRODUCTION 2
   - 3.1 About Lessons Learned 2
   - 3.2 Lessons Learned Process 3
   - 3.3 Historical Evolution to Current Project 3
   - 3.4 Project Objectives & Scope 4
   - 3.5 Scope of Lessons Learned 5
4. LESSONS LEARNED, INSIGHTS and EXEMPLARY PRACTICES 5
   - 4.1 Organization of Discussion 5
   - 4.2 Overall Project 5
     - 4.2.1 Lessons Learned 5
     - 4.2.2 Insights 7
     - 4.2.3 Exemplary Practices 7
   - 4.3 Carbon Dioxide Capture 8
     - 4.3.1 Lessons Learned 8
     - 4.3.2 Insights 11
     - 4.3.3 Exemplary Practices 11
   - 4.4 Carbon Storage 12
     - 4.4.1 Lessons Learned 12
     - 4.4.2 Insights 13
     - 4.4.3 Exemplary Practices 14
   - 4.5 Other Miscellaneous 15
5. CONCLUSIONS 15
6. APPENDICES 17
   - 6.1 Compilation of Miscellaneous Technical Lessons Learned for CO_2 Storage 17

Copyright © 2012 American Electric Power Inc. All Rights Reserved

LIST OF REFERENCES

1. CCS INTEGRATION REPORT TO GLOBAL CCS INSTITUTE
2. CO2 COMPRESSION REPORT TO GLOBAL CCS INSTITUTE
3. CO2 STORAGE REPORT TO GLOBAL CCS INSTITUTE
4. FRONT-END ENGINEERING & DESIGN REPORT TO GLOBAL CCS INSTITUTE

Copyright © 2012 American Electric Power Inc. All Rights Reserved

1. SYNOPSIS

The purpose of this report is to share select lessons learned, insights and exemplary practices from American Electric Power's Phase I – Project Definition activity associated with the Carbon Capture and Storage (CCS) system planned for installation at the company's Mountaineer Plant, located in New Haven, West Virginia, USA under US Department of Energy Cooperative Agreement No. DE-FE002673. Notwithstanding American Electric Power's (AEP) decision to dissolve the existing cooperative agreement and postpone project activities, AEP and its integrated project team successfully completed the Phase I effort for the Mountaineer Commercial Scale CCS project.

The front-end engineering and design package developed within Phase I incorporated knowledge gained and lessons learned (construction, operations, and process related) from the 20 MWe pilot Product Validation Facility (PVF) project for both the carbon dioxide (CO_2) capture and storage systems. The design package also established the fit, form, and function of the project including design criteria, mass and energy balances, plot plans, general arrangement drawings, electrical one-lines, process flow diagrams, P&IDs, etc.

The work completed in Phase I continues the advancement of Alstom's CAP technology toward commercial demonstration at the intended scale. The completed front-end engineering and design package also provides a sound basis for completion of the project when conditions warrant the continuation of this or a similar project elsewhere. The lessons learned, insights, and exemplary practices shared within this report should benefit other CCS projects.

2. EXECUTIVE SUMMARY

With a long historical record of delivering many electric utility industry innovations, coupled with a predominantly coal-fired electric generation fleet, AEP took an early leadership role in exploring the feasibility of retrofitting its coal-fired fleet with CO_2 capture and storage technologies. AEP undertook a measured approach in its leadership role that tracked the emergence of dialogue around future CO2-limiting policies in the US and abroad. Among other things, AEP engaged in a cost sharing agreement with the US Department of Energy (DOE) in 2003 to determine the geologic feasibility of storing CO_2 in deep saline reservoirs in the Ohio Valley. Based on the favorable results of the geologic characterization project, AEP selected the Alstom's Chilled Ammonia Process in 2007 for testing of their CO_2 capture technology at a 20 MWe pilot scale. Known as the Product Validation Facility, the project included carbon dioxide injection and deep saline storage. The 2009 proposed scale up of Alstom's Chilled Ammonia Process to a commercial scale project and AEP's financial commitment appeared to be in-sync with emerging US policy aimed at curbing CO_2 emissions. Key for AEP and its ratepayers, was the need to understand both the technical and financial viability of retrofitting coal-fired generation with CCS technology, given the impending emergence of federal legislation.

With the Mountaineer Commercial CCS II project, AEP and the DOE planned a phased approach to its execution with key decision points and phase gate off-ramps inserted at the end of each of Phases I & II. The decision points allowed for reflection of the work performed (e.g. technical and financial feasibility) within the phases and decisions on whether to proceed with subsequent project phases. Given the diminished prospects for future regulatory support and cost recovery due a lack of federal legislation, AEP informed DOE at the Phase I decision point of its intention to dissolve the project agreement and suspend

Copyright © 2012 American Electric Power Inc. All Rights Reserved

further work following the completion of Phase I. At the time of the communication, AEP noted that when the original grant application was submitted by AEP in response to DE-FOA-0000042, AEP believed it important to advance the science of CCS due to pending action regarding climate change legislation and/or regulations concerning CO_2 emissions at its coal-fired power plants. Various bills in Congress were introduced to limit emissions that also provide funding for early CCS projects. AEP also believed that regulatory support for the remaining cost recovery beyond the DOE or legislative support was probable given the potential for emission reduction requirements on an aggressive timetable. While AEP still believes the advancement of CCS is critical for the sustainability of coal-fired generation, the regulatory and legislative support for cost recovery simply does not exist at the present time to fund AEP's cost share of the Mountaineer Commercial Scale Project.

With the completion and documentation of the Phase I work, AEP and DOE have a good understanding of the project's risks; capital costs; and expected operations and maintenance costs. The completed front-end engineering and design package provides a sound basis for completion of the project when conditions warrant the continuation of this or a similar project elsewhere.

As a part of any project close-out, projects and engineering groups within AEP's generation business unit routinely document lessons learned. Lessons learned may consist of activities that were known to have negatively impacted the execution of a project or the performance of an organization or may be activities or events that worked well and had a positive effect. While a number of lessons learned were documented during project execution, most of the lessons learned were documented and compiled at the end of Phase I in a lessons learned meeting that followed an advance survey of project team members for lessons learned inputs. Over 20 participants, representing AEP, Alstom, Battelle and WorleyParsons input and/or participated in the review. Project lessons learned, exemplary practices and recommended process improvement were reviewed for understanding and/or were updated as a result of the meeting discussions. Lessons learned inputs were aggregated into three broad categories: Overall Project General, CO_2 Capture Effort and CO_2 Storage Effort.

The lessons learned discussions contained herein primarily pertain to the Mountaineer commercial scale CCS project. However, given the historical work leading up to and inputting to the commercial scale project a number of discussions draw on AEP's earlier experiences.

While a select number of notable lessons learned, insights, and exemplary practices are highlighted in this presentation, numerous others are shown in an Appendix to this report. The documented lessons learned, insights, and exemplary practices should serve a future project team, if and when the project resumes, others working on DOE funded projects and other CCS projects in general.

3. INTRODUCTION

3.1 About Lessons Learned

Lessons learned may consist of activities that were known to have negatively impacted the execution of a project or the performance of an organization or may be activities or events that worked well and had a positive effect. The projects and engineering groups, within AEP's generation business unit, routinely utilize lessons learned processes in execution of their projects. Through documentation and dissemination of lessons learned, project teams and organizations learn from and avoid the reoccurrence of miss-steps. Additionally, and equally as important, lessons learned processes may extend to the

Copyright © 2012 American Electric Power Inc. All Rights Reserved

identification of exemplary practices and recommended process improvements that help mature performing teams and organizations, increasing their value to and contributing to the bottom lines of their companies.

3.2 Lessons Learned Process

As noted above, lessons learned are routinely documented in the execution of projects. Project teams may be asked to document lessons learned following a specific incident, action or activity. Alternatively, lessons learned are compiled following completion of a short term project of a year or less; or, in the case of a long term project performed over multiple years, they may be compiled following the completion of a project phase (e.g. initial front-end engineering and design, detailed engineering, construction, and start-up and commissioning). As a phased project, the Mountaineer Commercial Scale CCS project (MT CCS II) held a lesson learned meeting following a survey of project team members for inputs in advance of the meeting. Inputs were requested for lessons learned, exemplary practices and process improvements. Over 20 participants, representing AEP, Alstom, Battelle and WorleyParsons input to and/or participated in the review. Project lessons learned, exemplary practices and recommended process improvement were reviewed for understanding and/or were updated as a result of the meeting discussions. The lessons learned, exemplary practices, and recommended process improvements were distributed to the participants and input to AEP's lessons learned data base repository.

AEP also held a separate day-long lessons learned meeting with Battelle to review overall technical related lessons learned from Battelle's support and participation on related carbon storage projects that first started in 2003; descriptions of those projects are contained in Section 3.3.

3.3 Historical Evolution to Current Project

AEP has been actively involved in the development of CCS technology over the past eight years. AEP's initial involvement in the development of CCS began in 2003 with the Ohio River Valley CO_2 Storage Project; US DOE's National Energy Technology Laboratory (NETL) sponsored the project under Contract No. DE-AC26-98FT40418. The project included the drilling, sampling, and testing of a deep well combined with a 2D seismic survey to characterize local and regional geologic features at AEP's Mountaineer plant. The work completed within the project laid the groundwork for site selection of the PVF based on its very detailed geologic characterization study.

In March 2007, AEP signed an agreement with Alstom to validate its Chilled Ammonia Process (CAP) technology via scale up to a 20-MWe Product Validation Facility (PVF). Alstom had previously constructed and operated a 1.7-MWe pilot scale CAP capture facility at the We Energies Pleasant Prairie Power Plant. The flue gas volume of the slip stream for the PVF is equivalent to the flue gas generated from a 20 MWe coal fired power plant. The PVF was designed to capture and store approximately 100,000 metric tons of CO_2 annually.

Captured CO_2 from the PVF was injected via two onsite wells into two geologic formations (Rose Run sandstone and Copper Ridge dolomite) at a depth of approximately 1.5 miles below the plant site. One injection well and three deep monitoring wells were drilled within the power plant property between 2008 and 2009. The characterization well, previously drilled in 2003 was re-worked and transformed into one of the two injection wells. The PVF provided critical data to support the design and engineering of the MT CCS II project.

Copyright © 2012 American Electric Power Inc. All Rights Reserved

In August 2009, AEP submitted an application to Department of Energy (DOE) to demonstrate the commercial viability for retrofitting the Mountaineer plant with a 235-MWe nominal carbon capture and storage facility, building on the work of the DOE supported Ohio River Valley CO_2 Storage Project, and including the non-DOE funded PVF. In December 2009, DOE announced the selection of the Mountaineer Commercial Scale Carbon Capture and Storage Project for funding under Round Three of the DOE's Clean Coal Power Initiative.

3.4 Project Objectives & Scope

AEP's objective for the MT CCS II project is to design, build, and operate a commercial scale carbon capture and storage (CCS) system capable of treating a nominal 235 MWe slip stream of flue gas from the outlet duct of the Flue Gas Desulfurization (FGD) system at the Mountaineer Plant, a 1,300 MWe coal-fired generating station located in New Haven, West Virginia. The CCS system is designed to capture 90% of the CO_2 from the incoming flue gas using the Alstom's CAP and compress, transport, inject and store 1.5 million metric tons per year of the captured CO_2 into deep saline reservoirs.

AEP and its integrated project team, including Alstom, Battelle and WorleyParson successfully completed the Phase I effort for the Mountaineer Commercial Scale Carbon Capture and Storage Project in accordance with US DOE Cooperative Agreement No. DE-FE002673, which provided 50% cost sharing to the project. Phase I of the project's cooperative agreement called for, among other things: the completion of front-end engineering and design (FEED); the development of an Environmental Impact Statement in accordance with the National Environmental Process Act (NEPA); and the identification of exceptionally long lead time items.

The front-end engineering and design package developed within Phase I incorporated knowledge gained and lessons learned (construction and operations related) from the PVF and the design package also established the fit, form, and function of the project including design criteria, process flow diagrams, mass and energy balances, plot plans, general arrangement drawings, electrical one-lines, flow diagrams, P&IDs, etc.

Based on the work completed in the front-end engineering and design package, AEP and its integrated project team also:

- Developed a +/- 25% cost estimate,
- Developed a detailed Phase II project schedule,
- Provided DOE with all information it needed to complete the NEPA process,
- Developed a multi prime construction contracting strategy for Phase III,
- Drilled a deep well for characterization of subsurface geology at one of the remote CO_2 storage sites,
- Issued preliminary PFD and overall mass and energy balances, and
- Completed preliminary project design.

Copyright © 2012 American Electric Power Inc. All Rights Reserved

3.5 Scope of Lessons Learned

The lessons learned discussions contained herein primarily pertain to the MT CCS II project. However, given the historical work leading up to and inputting to the MT CCS II project a number of discussions draw on AEP's earlier experiences. Specifics of lessons learned relating to Alstom's Chilled Ammonia Process technology are not addressed in this report due to the proprietary nature of that information; generalities are however noted consistent with the referenced topical project reports previously prepared for the Global CCS Institute. Specifics of a number of lessons learned pertaining to the work on CO_2 storage systems are however shared in this report.

While this report is titled a CCS Lessons Learned Report, the discussions contained herein also include insights and advice and discussion of exemplary practices.

4. LESSONS LEARNED, INSIGHTS AND EXEMPLARY PRACTICES

4.1 Organization of Discussion

The lessons learned discussions, insights, exemplary practices and other advice shared within this section are organized along broad classifications of: Overall Project General, Carbon Dioxide Capture Systems, and Carbon Dioxide Storage Systems. Select lessons learned are noted and discussed, while other lessons learned are listed in appendices. Within the broad classifications, the lessons learned discussed that are listed in the appendices may be further subcategorized by subject area (e.g. engineering/technical, regulatory, environmental, construction, project management, communications, etc).

The format employed for presenting the subject mater includes:

- A statement or description of the lessons learned, insight or exemplary practice;
- A recommendation for any listed lesson learned; and
- Discussion, as applicable for understanding and context for the lesson learned, insight or exemplary practice.

The lessons learned insights and exemplary practices listed and discussed in the sections to follow are judged to be some of the more significant issues worthy of listing and discussion; they are however randomly listed within the broad categories and are not shown in any prioritized ranking.

4.2 Overall Project

4.2.1 Lessons Learned

4.2.1.1 LACK OF FEDERAL LEGISLATION RELATED TO CO_2 EMISSIONS

Recommendation - Dissolve the existing cooperative agreement at the appropriate project phase decision point and postpone project activities.

Discussion - At the Phase I decision point to DOE, AEP communicated its plans to dissolve the existing cooperative agreement and postpone project activities following the completion of Phase I. At the time of the communication, AEP noted that when the original grant application was submitted by AEP in

Copyright © 2012 American Electric Power Inc. All Rights Reserved

response to DE-FOA-0000042, AEP believed it important to advance the science of CCS due to pending action regarding climate change legislation and/or regulations limiting CO_2 emissions at its coal-fired power plants. Various bills in Congress were introduced to limit emissions but also provide funding for early CCS projects. The Waxman-Markey Bill even passed the House but later failed to pass the Senate. AEP also believed that regulatory support for the remaining cost recovery beyond the DOE or legislative support was probable given the potential for emission reduction requirements on an aggressive timetable. While AEP still believes the advancement of CCS is critical for the sustainability of coal-fired generation, the regulatory and legislative support for cost recovery simply does not exist at the present time to fund AEP's cost share of the Mountaineer Commercial Scale Project.

4.2.1.2 PREPARATION OF THE ENVIRONMENTAL IMPACT STATEMENT (EIS) REQUIRED MORE UPFRONT TECHNICAL OR ENGINEERING INFORMATION THAN WAS INITIALLY AVAILABLE

Recommendation - Start engineering and hire the National Environmental Policy Act (NEPA) contractor as soon as practicable. Build 18 to 24 months into the project schedule for the NEPA process.

Discussion - Compiling information and having an Environmental Impact Statement (EIS) prepared is an intensive effort that requires the completion of some engineering to start the EIS development process. Environmental Impact Statements written around processes that are somewhat first-of-a-kind or new can add challenges to the NEPA process as many of the analyses and evaluations in the EIS require significant information from the process or technology. Since commercial scale CCS had not yet been demonstrated in practice, much of the technical information was based on calculated values, modeled effects, and assumptions.

4.2.1.3 CARBON DIOXIDE CAPTURE RETROFIT SYSTEMS MAY NOT BE PRACTICABLE FOR PLANT SITES LACKING AVAILABLE AREA FOR THE PROCESS EQUIPMENT

Recommendation – Recognize that carbon capture retrofit installations require significant space for installation and operations.

Discussion – The design for the MT CCS II project covers about 13 acres of plant property adjacent the existing 1300 MW unit. As a first-of-a-kind (FOAK) retro-fit facility, the design for the project includes buildings for visitor presentations, administrative staff, a laboratory and added warehouse space. The need for the additional buildings may or may not be applicable to other installations, based on their site specific circumstances. That being said, the amount of space needed for the retrofit project was a significant revelation to AEP; fortunately the Mountaineer plant site is not constrained by a lack of available space.

4.2.1.4 THE PROJECT TEAM GAINED A GREATER APPRECIATION FOR THE BENEFITS OF PERFORMING EARLY HAZARDS ANALYSES AND CONSTRUCTABILITY REVIEWS

Recommendation - Incorporate hazards analyses and constructability reviews in FEED activities.

Discussion – AEP's Engineering, Projects and Field Services organization continually strives to improve its recognition of hazards and incorporation of safety into its designs. Additionally, efforts to involve construction personnel in constructability reviews during front end engineering & design has had limited

Copyright © 2012 American Electric Power Inc. All Rights Reserved

success, primarily due to limited resources availability. As a FOAK project with many perceived hazards and concerns for first time construction of such a project, AEP and its integrated project team focused significant effort and resources to identify and address hazards and constructability issues. The effort and time spent proved far more valuable than anticipated contributing to, among others: the early identification and the efficient addressing of hazards during the FEED process; early identification of constructability concerns that led to cost savings opportunities; and a more robust cost estimate and construction schedule.

4.2.2 Insights

4.2.2.1 IN A FOAK APPLICATION, TRY TO INNOVATE FROM PROVEN TECHNOLOGIES

Discussion – FOAK applications or projects inherently carry a number of unknown uncertainties or risks, or in other words you don't know what you don't know until it happens. It's important to limit uncertainties or risks associated with new or unproven technologies without track records. A significant portion of the process equipment making up the CAP is readily used in the petrochemical industry. While scaling up the equipment design often led to a multiple process "train" approach within the broader process, the equipment considered for MT CCS II was not un-proven in industrial or petrochemical applications.

4.2.2.2 THE GREATEST COST RISKS FOR CCS PROJECTS MAY LIE IN THE STORAGE SIDE OF SUCH PROJECTS

Discussion – AEP and its integrated project team performed a critical review of the MT CCS II project cost estimate for application of risk based project contingency. AEP examined the CO_2 capture system cost estimate, and generally felt that the estimate contained more opportunities for cost savings than risks of cost increases. The greatest uncertainties and corresponding risks for cost increases were in the carbon storage side of the project, principally due to uncertainties associated with interpretation and application of the new Class VI Underground Injection Control (UIC) permit regulations for injection, monitoring and post closure care of carbon storage sites. Additional detailed discussion for this insight is contained in the Front-end Engineering and Design report on the MT CCS II project prepared for Global CCS Institute at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project>.

4.2.3 Exemplary Practices

4.2.3.1 HIGH RISK AND FOAK PROJECTS AND/OR PROGRAMS NEED TO BE CAREFULLY MANAGED FROM INCEPTION THROUGH PILOT TESTING AND COMMERCIAL DEMONSTRATION WITH STRATEGICALLY PLACED DECISION POINTS AND PHASE GATE OFF-RAMPS

Discussion – With a long historical record of delivering many electric utility industry innovations, coupled with a predominantly coal-fired electric generation fleet, AEP took a leadership role in exploring the feasibility of retrofitting its coal-fired fleet with CO_2 capture and storage technologies. AEP undertook a measured approach in its leadership role that tracked the emergence of dialogue around future CO_2-limiting policies in the US. As noted in the introduction, AEP first engaged in a cost sharing agreement with the DOE to determine the geologic feasibility of storing CO_2 in deep saline reservoirs in the Ohio

Copyright © 2012 American Electric Power Inc. All Rights Reserved

Valley, home to a number of AEP coal-fired generating plants. Based on the favorable results of the geologic characterization project, AEP selected the Alstom CAP for pilot testing of carbon dioxide capture and included CO_2 storage in the PVF project. The scale up of Alstom's CAP to a commercial scale project and AEP's financial commitment appeared to be in-sync with emerging US policy on limiting CO_2 emissions. Key for AEP and its ratepayers, was the need to understand both the technical and financial viability of retrofitting coal-fired generation with CCS technology, given the impending emergence of federal legislation.

With the Mountaineer CCS II project, AEP and the DOE planned a phased approach to its execution with key decision points and phase gate off-ramps inserted at the end of each of Phases I & II. The decision points, allowed for reflection of the work performed (e.g. technical and financial feasibility) within the phases and collective decisions on whether to proceed with subsequent project phases. Given the diminished prospects for future regulatory support and cost recovery due a lack of federal legislation, AEP informed DOE at the Phase I decision point of its intention to dissolve the project agreement and suspend further work following the completion of Phase I.

With the completion and documentation of the Phase I work, AEP and DOE have a good understanding of the project's risks; capital costs; and expected operations and maintenance costs during planned Phase IV operations. The completed front-end engineering and design package provides a sound basis for completion of the project when conditions warrant the continuation of this or a similar project elsewhere.

4.2.3.2 COMMUNICATE OFTEN WITH THE PUBLIC

Discussion – Be sure to develop a communications plan for your project and ask plant employees that live in nearby communities to review and comment on it before rolling it to the public. Plan for and conduct meetings with local government and public officials before the start of major work on site; include public open houses and/or town hall meetings to describe the project and address any concerns. AEP held annual town hall meetings to update community leaders on project status and plans for the upcoming year. Example presentations or discussions might include among others, an exhibit showing the type of truck and geophone used to perform 2D seismic studies (e.g. noise from pounding the ground and tracking energy waves) and a heads-up of crew schedules for walking down proposed CO_2 pipeline transport corridors.

4.3 Carbon Dioxide Capture

4.3.1 Lessons Learned

4.3.1.1 CARBON DIOXIDE CAPTURE SYSTEMS ARE CHEMICAL PLANTS THAT HAVE A DIFFERING OPERATING PHILOSOPHY THAN ELECTRIC POWER PLANTS

Recommendation – The CO_2 capture technology provider and electric utility owner need to recognize and address operational philosophy differences and process dynamics limitations early in the design process.

Discussion - Power plants and chemical plants have differing operational philosophies. Examples include: 1) chemical plants produce a uniform product from a uniform feed stock whereas power plant

Copyright © 2012 American Electric Power Inc. All Rights Reserved

electrical energy production is based on demand closely tied to weather; 2) chemical plants have stable production rates with consistent production schedules whereas power plants have frequent power output adjustments based on time of day and load following; and 3) coal-fired power plants have a variable fuel feedstock whereas variability of feedstock to chemical plants is minimized to reduce impacts. Additional issues include: access, maintainability related to outage durations, and safety policies that added to cost; see the referenced CCS Integration report for additional detailed discussion at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project>.

4.3.1.2 SOURCING AND QUALITY OF STEAM IS IMPORTANT

Recommendation – Carefully consider the extraction source(s) of steam relative to the needs for the CO_2 capture retrofit system; depending on the size of the carbon dioxide capture system, a stand alone or independent steam supply source may be more desirable.

Discussion – As discussed at length in the CCS Integration Report at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project>, the project team decided to extract steam at two different pressure levels and utilize throttling valves for supply of steam to the carbon dioxide capture regeneration and process stripping systems. The selection points and quality of steam supply met the needs for the system at the intended scale-up size. However, if one were to design a commercial scale system capable of treating the entire flue gas discharge, and independent steam supply source would need to be considered. It must be understood that selection of the steam source is highly site-specific and project-specific. Because this was a slipstream demonstration project, AEP was reluctant to accept significant modifications to the steam turbine that could have impacted future operations once the CCS project was completed. That design criteria then factored into the overall decision of where to extract steam.

4.3.1.3 UNCLEAR CRITERIA FOR OPERATIONS VERSUS CAPITAL COSTS CAN LEAD TO REANALYSIS AND DELAY.

Recommendation - Establish criteria for operating versus capital costs early in the project.

Discussion – Early consideration of evaluation criteria (e.g. reliability, maintainability and availability) by owner and technology provider teams helps avoid later focus on the wrong driver for a design decision.

4.3.1.4 INSURE THAT PRELIMINARY EQUIPMENT SIZING CAN BE PRACTICABLY FABRICATED AND SHIPPED TO SITE.

Recommendation – Work with one or more potential equipment suppliers during initial design.

Discussion – FOAK system projects, in a scale-up stage will lead to new sizing or reconfiguration of equipment. Equipment suppliers will likely have insights regarding practical limitations of sizing and/or cost savings ideas for reconfiguration of equipment subsystems or components. The challenge to the FOAK technology and/or overall project owner is to determine when it may be in the best interests of the project to involve equipment suppliers in early design discussions, including the need to compensate them for resources utilized in providing the inputs.

4.3.1.5 A DEDICATED EXHAUST STACK MAY BE PREFERRED AND/OR REQUIRED

Copyright © 2012 American Electric Power Inc. All Rights Reserved

Recommendation – Carefully consider the need for a new dedicated exhaust stack, including the lead time needed for permitting.

Discussion – As discussed in more detail in the CCS Integration report at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project>, the project team considered use of the existing plant stack, construction of a new stack and also possible use of the existing plant hyperbolic cooling tower as an exit point for the treated gas stream. While the team initially recommended a new dedicated stack, uncertainties and lead times associated with modeling and permitting of a new stack became a disincentive. The team returned treated gas back to the existing plant stack as a basis for the project cost estimate. However, for treating higher percentages of flue gas, a dedicated exhaust point may be required as the technical difficulties surrounding mixing of flue gas streams and gas stream temperatures may become a concern.

4.3.1.6 GRAY WATER MANAGEMENT IS A SIGNIFICANT CHALLENGE

Recommendation – Turn gray water into a marketable product

Discussion – The gray water by-product bleed stream, containing ammonium sulfate, can be made into a marketable product as feedstock for manufacture of fertilizer. For Mountaineer's gray water to be considered desirable, the concentration of ammonium sulfate solution needed to be at least 40%. Contacting potential end users early in the design process to better understand the types of products they can utilize can prove beneficial. As an aside, fresh water make-up for evaporation and losses did not require additional make-up capacity at Mountaineer. Again this is project specific, but avoiding the expense and balance of plant related impacts of adding make-up water capacity were significant factor in the overall design process.

4.3.1.7 AEP EVALUATED A NUMBER OF REAGENTS FOR THE CHILLED AMMONIA PROCESS

Recommendation - Anhydrous Ammonia is the optimal reagent for the CAP.

Discussion – The project team evaluated a number of reagents for use in the CAP refrigeration system. The chilled ammonia process uses ammonia solution as chemical solvent to remove CO_2 from the flue gas. Ammonia is the single natural refrigerant being used extensively in industrial applications for its good thermodynamic and thermophysical characteristics. While ammonia is an excellent refrigerant, it is also a hazardous substance. Although hazardous, there are well established practices, common in industry, for the safe handling of anhydrous ammonia. The evaluation and comparisons carried out by the project team showed that an ammonia refrigeration system is optimal for the Mountaineer CCS II project. This system has the lowest energy consumption (highest efficiency) and the lowest installed capital cost, with minimal environmental impact with respect to ozone depletion, greenhouse effect, or global warming.

4.3.1.8 ASSUMPTION OF HIGH CO_2 INJECTION WELL PRESSURES

Recommendation – CO_2 compression to an intermediate pressure, followed by variable speed pumping to the final injection pressure offers the greatest flexibility and efficiency over the life of the system as compared to full compression to the maximum expected injection pressure.

Discussion – Injection well pressures in the range of 1200 – 1500 psi range are expected early in the life of the target injection wells. Maximum injection pressure into the geological formations targeted for this

Copyright © 2012 American Electric Power Inc. All Rights Reserved

project is expected to be 3000 psi. It should be noted that the allowable maximum injection pressure depends on the permitting agency and the fracture gradient of the reservoir and the cap rock. See the referenced CO2 Compression Report for additional discussion at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project>.

4.3.2 Insights

4.3.2.1 BUILD FLEXIBILITY INTO PLANT INTERFACE POINTS TO ALLOW FOR AND/OR ACCOUNT FOR UPSET CONDITIONS.

Discussion – The CCS integration report, furnished to Global CCS Institute at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project> discusses at length AEP's approach for integrating FOAK retro-fit technologies and the need to build flexibility into plant interface points. Design basis for plant interface points can be refined later based on operating experience.

4.3.3 Exemplary Practices

4.3.3.1 INVOLVE APPROPRIATE PLANT PERSONNEL IN ALL DISCUSSIONS SURROUNDING CRITICAL INTERFACE POINTS (E.G. STEAM TURBINE, RIVER WATER INTAKE, AND OTHER CRITICAL PROCESSES)

Discussion – Plant personnel have greater awareness for and key insights regarding operational flexibility of their plant systems. Involvement of plant personal from the onset of the project contributed to a higher confidence of the design basis, improved communication of ideas, and minimized obstacles to plant understanding and acceptance.

4.3.3.2 THE PROJECT TEAM'S USE OF A 3D MODEL DURING PRELIMINARY PROJECT DESIGN PROVIDED NUMEROUS BENEFITS

Discussion – The 3D model developed for the project proved to be invaluable to the integrated project team. As the model was developed, it was reviewed on a monthly basis by project team members representing, among others: construction, engineering, plant personnel, and project management. The model not only helped with understandings of equipment sizing and relationships to existing plant infrastructure, but it also helped the team develop a detailed materials list and robust cost estimate; as an example, the team was able to account for piping sizes down to a 2-1/2 inch (6.35 cm) diameter. The model also aided project constructability reviews. Overall, the project team felt that the use of the model increased everyone's confidence in the final project cost estimate.

4.3.3.3 AEP AND ALSTOM COLLOCATED ENGINEERING PERSONNEL AND UTILIZED INTEGRATED PROCESS DESIGN WORKSHOPS

Discussion – The start of design for the MT CCS II project overlapped with the operation of the PVF. As a result, lessons learned from the PVF were still being revealed and/or compiled during early MT CCS II design activity. AEP and Alstom decided to collocate engineering and plant personnel, alternating in offices both in the US and in Europe, to speed an in depth understanding and application of the lessons

Copyright © 2012 American Electric Power Inc. All Rights Reserved

learned from the PVF. The process design workshops helped speed the integrated project team's collective understanding of capture subsystems in a way that allowed for transparency and buy-in from plant personnel that ultimately would be tasked with operation of the systems. The process design workshops also contributed to a higher level of confidence for the overall system design.

4.4 Carbon Dioxide Storage

4.4.1 Lessons Learned

4.4.1.1 CO_2 INJECTION AND MONITORING WELLS ARE NOT "BUSINESS AS USUAL" FOR ANY REGULATOR.

Recommendation - Partner with regulators and others as needed early in the permitting process.

Discussion - Underground Injection Control (UIC) regulations, promulgated by the US Environmental Protection Agency (EPA) are new and may be unfamiliar to state regulators. States targeted for CCS projects will also need to develop their own regulations to comply with US EPA requirements before they can be authorized to process and permit CO_2 storage projects.

4.4.1.2 THE PROJECT TEAM DID NOT HAVE AN APPRECIATION FOR NECESSARY LEAD TIMES TO SECURE PROPERTY ACCESS RIGHTS FOR LOCATING CO_2 TRANSPORT PIPELINES.

Recommendation – Involve land management professionals early in the development of any project schedule.

Discussion – The project team did not have an appreciation for the lead times necessary to secure property access rights, causing some schedule delay. Land management personnel should be consulted when developing the Level I or II inputs to the overall project schedule. In a related matter, project team incorrectly assumed that the location of transport pipe lines within right-of-ways for transmission lines would lessen permitting needs.

4.4.1.3 THE DRILLING SCHEDULE DID NOT ACCOUNT FOR COMMON RISK FACTORS THAT CAN IMPACT THE PLANNED SCHEDULE OF COMPLETION.

Recommendation – Acknowledge risk factors in the drilling operation and incorporate them into the schedule.

Discussion – The drilling of the BA-02 characterization well proceeded on a tight schedule that in hind site was optimistic and did not consider common risk factors associated with drilling deep wells. Example risk factors might could include among others: failed parts and machinery and the need to maintain adequate spare parts onsite or in close proximity, encountering fluid when drilling on air, encountering excessive fluids in formations, loss of circulation during cementing, fishing tools out of a bore hole, etc. Project teams should work with their drilling crews to anticipate possible risk factors and their probabilities for occurrence and build an appropriate level of contingency into the overall schedule for drilling, and project schedule as applicable.

Copyright © 2012 American Electric Power Inc. All Rights Reserved

4.4.1.4 NEW GEOLOGIC HORIZONS MAY AVAIL THEMSELVES AS BONA FIDE CO_2 STORAGE TARGETS

Recommendation – Consider, to the extent practicable, the drilling of multiple characterization wells over an expanded area.

Discussion – Based on the drilling of the BA-02 characterization well and the subsequent down hole testing, the project team confirmed the Lower Copper Ridge zone was viable beyond the area immediately surrounding the Mountaineer Plant. Prior to work at Mountaineer, this zone was not previously understood to have characteristics suitable for CO_2 storage.

4.4.1.5 GEOPHYSICAL TECHNIQUES SUCH AS SURFACE SEISMIC HAVE RESOLUTION LIMITATIONS

Recommendation – Reservoir testing is crucial during the characterization process.

Discussion – Surface seismic techniques cannot resolve thin horizons. The formations in the Mountaineer plant area are only approximately 30 ft (10 m) thick. Detailed log analyses (which have high resolution of approximately 1ft) and subsequent hydrologic testing of the target reservoirs were crucial in calculating the storage potential of the formation.

4.4.2 Insights

4.4.2.1 INSURE THAT STATE LEVEL POLICIES ARE IN PLACE TO SUPPORT CO_2 INJECTION AND STORAGE; LEAD TIMES TO DO SO CAN SPAN MANY YEARS.

Discussion - CO_2 injection and storage could become cost prohibitive without state level policies, in the form of enabling legislation and regulations that frame the responsibilities and rights of the entities that inject CO_2 and adjacent property owners, respectively. State policies should address, from among other issues: financial responsibility, use of pore space, property rights, liability, eminent domain and permitting fees. Additionally, project teams need to consider the possible migration of injected CO_2 into other regulatory jurisdictions (i.e. adjacent states), as many coal-fired electric utility plants are located along rivers that form boundaries with other state regulatory jurisdictions.

The lead time necessary to develop state level policies, in the form of legislation and regulations can approach three to four or more years, depending on the extent of stakeholder interest and the overall priorities of state executive and legislative branches. For example, AEP has been working with West Virginia policy makers and other stakeholders on CCS issues for over four (4) years. During the 2009 legislative session, the West Virginia Legislature passed a bill acknowledging that it is in the public interest to advance the implementation of carbon dioxide capture and sequestration technologies into the state's energy portfolio. Recognizing the administrative, technical and legal questions involved in developing this new technology, the Code authorized the West Virginia Department of Environmental Protection Secretary to establish a Carbon Dioxide Sequestration Working Group (Working Group). The Working Group was charged with studying all issues related to the sequestration of carbon dioxide and to submit a preliminary report to the Legislature on July 1, 2010, followed up by a final report on July 1, 2011. The preliminary and final reports were delivered to the legislature. The final report, however, addresses, among other things recommended legislation to help encourage the widespread use of CCS

Copyright © 2012 American Electric Power Inc. All Rights Reserved

in West Virginia. Proposed legislation still needs to be introduced and considered by the legislative body; a process that can take one or more years to complete.

4.4.2.2 LEADING CCS PROJECTS NEED TO ACCOUNT FOR UNCERTAINTY WITH FIRST TIME APPLICATION OF UNDERGROUND INJECTION CONTROL (UIC) PERMITTING GUIDELINES.

Discussion – An initial Class VI UIC permit application for a CCS project has yet to be submitted and approved by any state regulatory jurisdiction within the US. Initial review and approval of first time permit applications in any state could become subject high stakeholder interest and prolonged agency review, leading to schedule delay. Additionally, uncertainty regarding the number of shallow, intermediate and deep monitoring wells that might be required by a first UIC permit issuance must be accounted for in project cost estimate assumptions and risks until such time that a UIC permit is received.

4.4.2.3 LOOK FOR OPPORTUNITIES TO PURCHASE PREVIOUSLY COMPLETED 2D SEISMIC STUDIES IN AN AREA OF INTEREST.

Discussion – AEP purchased two 2D seismic lines to enhance its understanding of the regional geology, at a cost savings to the project. AEP also began to appreciate the potential to partner with other area projects that may be drilling in the area (e.g. shale gas exploration). Example partnering arrangements might include exchanging logging data, funding additional drill rig time and effort to perform various optional characterization tests at other nearby drilling sites, etc.

4.4.2.4 CONSIDER THE NEED TO ESTABLISH SITE SELECTION CRITERIA TO EVALUATE PROPERTIES FOR THE WELLS AND PIPELINE CORRIDORS.

Discussion – AEP's selection of candidate well injection sites focused on: property owned by the company in West Virginia; locations which required minimal right-of-way interferences for pipelines and access to the sites; and sites within relative close proximity to the Mountaineer plant. In the course of building a cost estimate for the project, it became apparent that some sites, on closer inspection, had significant developmental costs for access. In retrospect, the project team may have benefitted from having developed site selection criteria based on input from a multi-discipline team (e.g. engineering, environmental, geology, legal, project management). Future projects should consider the need to establish site selection criteria and apply the criteria as early as possible in the conceptual design phase of the project.

4.4.3 Exemplary Practices

4.4.3.1 FORM AND UTILIZE A GEOTECHNICAL EXPERTS ADVISORY GROUP

Discussion - Public acceptance of carbon dioxide storage depends in part on a thorough characterization and assessment of the underlying geology, including the ability of target reservoir zones to receive and store CO_2 without impact to the groundwater resources. AEP expected that, not only would the project development be more robust, but also the public would be more accepting of the ultimate design for the CO_2 injection and monitoring program if a geotechnical advisory group was formed from a wide ranging group of interested and knowledgeable stakeholders (i.e. experts) to broaden and bolster

Copyright © 2012 American Electric Power Inc. All Rights Reserved

the resource expertise levels that were applied to the project, and include their input to the design philosophy and permitting strategy.

4.5 Other Miscellaneous

AEP also held a separate day-long lessons learned meeting with Battelle to review overall technical related lessons learned from Battelle's support and participation on AEP related carbon storage projects that first started in 2003; select technical lessons learned from the Battelle meeting were compiled and are shown in an Appendix 6.1.

5. CONCLUSIONS

Notwithstanding AEP's decision to dissolve the existing cooperative agreement and postpone project activities, AEP and its integrated project team successfully completed the Phase I effort for the Mountaineer Commercial Scale Carbon Capture and Storage Project, as outlined in the cooperative agreement. Within Phase I, the cooperative agreement called for:

- The resolution of outstanding conditions with the U.S. Department of Energy (DOE) cooperative agreement;
- Project specific developmental activities (i.e., front-end engineering and design);
- The initiation of the NEPA process; and
- The identification of exceptionally long lead time items.

The front-end engineering and design package developed within Phase I incorporated knowledge gained and lessons learned (construction and operations related) from the PVF and the design package also established the fit, form, and function of the project including design criteria, mass and energy balances, plot plans, general arrangement drawings, electrical one-lines, flow diagrams, P&IDs, etc.

Based on the work completed in the front-end engineering and design package, AEP and its integrated project team also:

- Developed a +/- 25% cost estimate,
- Developed a detailed Phase II project schedule,
- Provided DOE with all information it needed to complete the NEPA process,
- Developed a multi prime construction contracting strategy for Phase III,
- Drilled a deep well for characterization of subsurface geology at one of the remote CO_2 storage sites,
- Issued preliminary PFD and overall mass and energy balances, and
- Completed preliminary project design.

The work completed in Phase I continues to support positive advancement of the Alstom CAP technology toward commercial demonstration at the intended scale. The work completed also provides AEP and DOE with a good understanding of the project's risks, capital cost, and expected operations and maintenance costs for planned Phase IV operations. The completed front-end engineering and design package provides a sound basis for completion of the project when conditions warrant the continuation of

Copyright © 2012 American Electric Power Inc. All Rights Reserved

this or a similar project elsewhere in the US and the lessons learned, insights, and exemplary practices shared within this report should benefit other CCS projects.

Copyright © 2012 American Electric Power Inc. All Rights Reserved

6. APPENDICES

6.1 Compilation of Miscellaneous Technical Lessons Learned for CO_2 Storage

(Note: Some of the items discussed below have their origins in previous work done by AEP outside the scope of this project. AEP used the knowledge gained in earlier work to further enhance the value of this commercial-scale project and build upon those earlier foundations. It is AEP's contention that sharing such information in this document is of great benefit to future project efforts AND, THUS, WHY THEY HAVE BEEN INCLUDED.)

Well Design:

- Larger diameter tubing in injector wells aided in CO_2 deliverability to the reservoir. Also, larger diameter injection tubing should help to avoid plugging issues and allow a more diverse suite of wire line tools to be run.
- The annular system may need to be reworked so as to avoid future mineral precipitation in the injection tubing string. This may include:
    - Detection and prevention of tubing damage during installation
    - Sensitive annulus pressure or fluid level detectors for sensing minute leaks of annular fluid out of the annular space
    - Use of annular fluid that is less likely to precipitate minerals in a dry (CO_2) environment (e.g. KCl weighted fluid is more expensive but has lower potential for mineralization than CaCl)
    - Periodic injections of water, or some fluid, for removal/dissolution of minerals from injection tubing
    - Use of scale inhibitors in injection tubing
    - Use of tubing material that inhibits coalescence of precipitates
    - Use of larger diameter injection tubing (i.e. tubing with larger minimum ID restriction)
- Real-time down hole temperature and pressure gauges are difficult to work around; may look at "wireless" options in the future
- May want to look at a horizontal injection well option in lower permeability formations (e.g. Rose Run)
- May look at multi-completion monitoring wells for monitoring in separate reservoirs – instead of having one monitoring well per reservoir
- The small diameter of AEP-1 was an issue, particularly since this well was used as an injection well. In this case, this was due to the fact that this well was not originally designed to be an injection well, but rather a characterization well. Nevertheless, avoid small diameter wells in the future.
- Stainless steel casing requires special running equipment, including high torque power tongs and special dies.

Permitting:

- Class VI regulations require a separate UIC permit application for each injection well (no area permits). In addition, five (5) companion plans must be prepared and submitted with the permit application, including: Area of Review and Corrective Action Plan; Testing and Monitoring Plan;

Copyright © 2012 American Electric Power Inc. All Rights Reserved

Emergency and Remedial Response Plan; Well Plugging Plan; Post Injection Site Care and Site Closure Plan.

- Financial assurance requirements under Class VI regulations require payment up front to cover 50 years of post injection monitoring, corrective action, well plugging, and other items. This must be arranged by the time the UIC permit application is submitted.

Drilling:

- Use Geotech/pilot hole to help guide conductor/surface casing design/placement
- When drilling in bedrock plan on a larger diameter conductor hole
- Have spare parts, pumps and air compressors on hand

Well Logging - Collection:

- Ensure baseline PNC logs are run after sufficient amount of time has passed from drilling the well
- Can run fewer "high-end/expensive" open hole logs in well-established areas

Well Logging – Analysis:

- Better data management from start of project – faster data integration

Well Coring – Data Analysis:

- Collect more whole core samples from injection zones
- Perform more SCAL tests to be used for model input parameters (e.g. mercury injection, geomechanical)

Injection Testing – Data Collection:

- High Priority, especially for "first" well in project/region
- Allow sufficient time for multi-zone (i.e. with packers) injection testing
- Equipment Planning – Thoroughly Vet Vendors (experience, novelty of what we planned)
- Procurement of high quality open hole packers for zone isolation
    - Should have multiple back-ups on-site
    - Should be field-serviceable
- Real-time down hole gauges for injection testing should be robust and field-serviceable
- Design well injection system to allow shutdown and shut-in (for reservoir characterization)
- Final key in characterization logging → core → reservoir test
- Thoroughly/accurately plan/schedule/budget, including contingencies (plan for failures, be flexible, nimble)
- Online/live data analysis during testing is strongly desired
- The flow meter logging surveys were very successful in identifying candidate in-flow zones for subsequent detailed hydrologic (packer) tests. In addition, collection of a temperature log 24 hours after the final dynamic logging survey provided valuable information to corroborate the results of the flow meter logging surveys. Strongly recommend incorporating flow meter logging surveys in all future well characterization programs in addition to standard coring and well logging programs.
- The discrete depth interval hydrologic (packer) tests were very successful in quantifying critical reservoir hydrologic parameters needed to identify candidate CO_2 injection zones and assess (model) CO_2 injectivity. Strongly recommend incorporating hydrologic (reservoir) testing in all future well characterization programs in addition to standard coring and well logging programs.

Copyright © 2012 American Electric Power Inc. All Rights Reserved

- It was prudent to allow time between the Phase I reservoir testing (flow meter logging) and Phase II reservoir testing (packer tests conducted within individual discrete-depth interval zones) to allow time to select target zones for detailed testing.
- Conducting both injection and withdrawal slug/DST tests is important.
- A service rig with a swabbing unit is essential for supporting the reservoir testing work. A drill rig is not required, and would not have the ability to conduct swabbing.
- Packer bypass (cross formational flow) was observed during some of the constant rate injection tests. Although injection pressures were well below fracture pressure, it is recommended to use low injection pressures in future injection testing.
- It is important to have a portable pump on site that can be used to inflate the packers and load the tubing string for injection slug/DST tests. This way, the pump truck only needs to be called to the site for the longer-duration constant rate injection tests. We used a rental pump for this purpose, and it turned out to be a cost saver.

Injection Testing – Data Analysis:

- Should allocate more staff time for analysis of injection testing data
- Software proved to very useful for analyzing reservoir pressure data for the purpose of characterizing reservoir properties.
- It is important to regularly analyze reservoir pressure data (injection/fall-off events) from the injection wells and monitoring wells. This was easy for the injection wells because bottom hole pressure data was obtained in real time; whereas, data from the monitoring wells was available only when gauges were pulled.
- Injectivity index is a useful parameter for tracking overall injection performance.
- Use of pressure memory gauges in the monitoring wells was appropriate and cost effective vs. real-time pressure monitoring systems for the short duration of this project. For longer-duration injection projects, real-time pressure monitoring systems may be more cost effective.

History Matching – Pressure Data:

- Develop workflow/process for interpreting and integrating results of CO_2 injection data
- Could have used lower pressure data sampling rate in monitoring wells and, to a degree, the injection wells
- More data accessibility in the future –continually self-updating data stream instead of weekly spreadsheet updates
- Good effort so far, need to do more, especially in correlation of pressure front and CO_2 front
- Pressure monitoring is very promising, but more modeling/analysis is needed [but geophysical methods may be at same state of development]

Geophysics:

- Need 3D data (could drive land acquisition), identifies faulting SE, guides risk
- Acknowledge limitations on purchased data (→can drive need for acquisition)
- Include detailed geomechanics
- Modeling effort (guides injection pressure) can minimize need for seismic
- Integrate seismic data is static model
- PNC – useful, low cost (allow time post drilling)
- Consider operation issues in planning repeats
- Fluid sampling shallow groundwater

Copyright © 2012 American Electric Power Inc. All Rights Reserved

- Soil Gas – likely needed, will be very labor intensive
- Groundwater monitoring – key to involve local plant expertise

Others:

- Use ongoing monitoring to guide future monitor needs (5yr→30yr) {adaptive strategy}
- Brine – target is to determine CO_2 breakthrough
- Satellite surface upheaval monitoring could be valuable

Copyright © 2012 American Electric Power Inc. All Rights Reserved

Appendix D

AEP Comments on the 2012 Proposed GHG NSPS for New Sources

AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

Original by Mail
E-mail copy submitted to: a-and-r-docket@epa.qov

June 25, 2012

EPA Docket Center
U.S. Environmental Protection Agency
Mail Code #2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460

ATTN: Docket ID No. EPA-HQ-OAR-2011-0660

Re: *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*
Docket ID No. EPA-HQ-OAR-2011-0660

American Electric Power (AEP) appreciates the opportunity to submit the attached comments on the Environmental Protection Agency (EPA)'s proposed standard of performance (NSPS) for greenhouse gas (GHG) emissions from electric generating units (EGUs) under § 111 of the Clean Air Act (CAA or the Act). AEP is a holding company and, through its public utility operating companies and other subsidiaries, ranks among the nation's largest generators of electricity. AEP companies own over 37,000 megawatts of generating capacity in the U.S and deliver electricity to more than 5.3 million customers in 11 states. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765-kilovolt extra-high-voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia, West Virginia and Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas). AEP's

Utility Air Regulatory Group (UARG), the Coal Utilization Research Council (CURC), and incorporates by reference the comments submitted by these groups.

Should you have any questions or need clarification regarding these comments, please direct them to me at 614-716-1268 or Frank Blake at 614-716-1240.

Respectfully submitted,

John M. McManus
Vice President - Environmental Services
American Electric Power

cc: Office of Information and Regulatory Affairs, OMB
Attn: Desk Officer for EPA
725 17th Street. NW,.
Washington, D.C. 20503

Mr. Kevin Culligan U.S. EPA (by email)
Mr. Christian Fellner, U.S. EPA (by email)
Dr. Nick Hutson, U.S. EPA (by email)
Mr. Peter Tsirigotis, U.S. EPA (by email)
Dr. Robert Wayland, U.S. EPA (by email)

Outline of AEP Comments:

I. AEP Is an Industry Leader on GHG Emission Reductions and Climate Change Policy

II. EPA's Combination of Two Existing Section 111 Source Categories Into a New NSPS Source Category For One Pollutant Is an Arbitrary and Capricious Departure From Prior Agency Practice

A. EPA has not complied with the requirements for publishing categories of stationary sources under Section 111 of the Clean Air Act

B. EPA has not demonstrated that NGCC is the best system of emission reduction for the proposed category

i. NGCC is not a "system of emissions reduction"

ii. EPA's justifications for selecting NGCC as the "best system of emission reduction" are not supported by logic or the facts

C. EPA's proposed Subpart TTTT raises adverse policy concerns

i. EPA's proposal would trigger PSD program obligations

ii. EPA's proposal would eliminate new coal-fired generation

III. EPA Must Provide Adequate Assurance That Its Proposal Will Not Affect Existing Sources

A. The proposed NSPS does not apply to modified or reconstructed sources

B. The proposed NSPS is not a BACT floor

IV. EPA's Proposed Rule Is Based On Faulty Data

A. Cost analysis

B. Selection of 1,000 lb CO_2/MWh emission rate

C. IPM modeling

D. Levelized cost analysis

E. Benefit analysis

V. Carbon Capture and Storage Is Not Commercially Available For Coal-Based Generation and Will Not Become a Viable Control Option Until Significant Challenges Are Addressed

A. Technically feasible is not the same as commercially available

B. Significant technical, financial, regulatory, and legal barriers exist that must be addressed before CCS is commercially acceptable for coal-based generation

C. Numerous public and private organizations have concluded that CCS for coal-based generation is not commercially available and that significant development barriers remain

D. AEP's experience demonstrated both the potential of CCS and the significant challenges that still must be addressed

E. EPA's rationale is insufficient for concluding that CCS is a feasible control technology option for coal-based generating units

i. First EPA basis: The "Technical Feasibility of CCS"
ii. Second EPA basis: "Expected reduction in CCS costs"
iii. Third EPA basis: "Limited amount of construction of new coal-fired power plants"
iv. Fourth EPA basis: "State Requirements for CCS"

VI. EPA Must Provide Adequate Assurance That Its Proposal Will Not Affect Existing Sources

A. The proposed NSPS does not apply to modified or reconstructed sources

B. The proposed NSPS is not a BACT floor

VII. Response to Technical Questions for Which EPA Solicited Comments

A. Use of gross-based output limits

B. Adequacy of the proposed 1,000 lb CO_2/MWh NSPS

C. CCS as the Best System of Emission Reductions

D. Coal refuse

E. Combined heat and power

F. Stationary simple cycle turbines

VIII. Conclusion

A. Fuel-specific standards should be established in lieu of a one-size-fits-all approach that effectively requires one fuel (coal), but not another (natural gas) to use an undeveloped control technology

B. EPA should not base a standard on technology that is not commercially available, but if EPA insists on promulgating a standard based on projected future technology developments, the long-term average limit should be revised to align with a more realistic CCS development timeline

C. EPA should either withdraw its proposed rule or convert it to an advance notice of proposed rulemaking, and continue gathering information

Appendix A: Assessments of the State of CCS Development for Coal-Based Electric Generation

I. AEP Is an Industry Leader On GHG Emission Reductions and Climate Change Policy

AEP has a long history of proactive involvement in stewardship activities. Beginning in the 1940's, AEP was involved in re-forestation programs, including specific efforts at portions of its large land holdings to return acreage that had been devoted to agricultural and mining activities to potential carbon sinks. In 1995, AEP committed to plant over 15 million trees in one five-year period as part of its participation in the U. S. Department of Energy's Climate Challenge Project. AEP has also pioneered international and domestic efforts to preserve existing forested lands, increase the number of actively managed forested acres in state and federal preserves and wildlife areas, and to create newly forested areas where the sequestration potential of good forest management projects could be studied to help develop the tools to quantify creditable increases in the sequestration of CO_2.

In 2003, AEP became a founding member of the Chicago Climate Exchange (CCX), the first voluntary GHG credit trading system in the U. S. AEP established and met goals to reduce or offset GHG emissions by an annual target of 6% (compared to emission levels during 1998-2001) by 2010. AEP has voluntarily established a further goal of reducing or offsetting our GHG emissions by 10% (compared to 2010 levels) by 2020.

AEP has participated in EPA's Climate Leaders Program, earning recognition and awards for innovation and achievement. In 2006, the Carbon Disclosure Project named AEP to its Climate Leadership Index, placing AEP among 50 other international corporations whose strategic awareness of the risks and opportunities associated with carbon constraints, and effective programs to reduce overall GHG emissions, have earned similar distinctions.

Since 2002, AEP has worked diligently to refine large scale sodium sulfur battery technology, and was the first utility to install and demonstrate this advanced energy storage technology as a means to bridge the gap between intermittent renewable resources, such as wind and solar power, and the constant need for on-demand electric service. Sodium sulfur storage batteries are now being integrated into the "smart grid" to improve transmission reliability and provide emergency power.

AEP's leadership and innovation in our core generation, transmission and distribution services has led to improvements in the efficiency of the delivery of our product through continual advances in generation technology efficiency, lowering transmission line losses,

energy audits, support for improvements in the efficiency of end-use appliances and fixtures, and improved delivery of real-time pricing and usage information through the electric grid. AEP Ohio recently announced that its business customer energy efficiency programs in Ohio have resulted in over 600 million kilowatt-hours of energy savings, enough power to serve 56,000 homes for one year.

AEP has also played a major role in supporting Congressional action to establish comprehensive climate change legislation that can use the power of markets to capture additional reductions in GHG emissions. AEP supported efforts in 2009 to design common-sense climate change legislation that would allow the United States to achieve significant progress in reducing GHG emissions without sacrificing the opportunity for the U.S. to remain economically secure and to retain domestic jobs.

Throughout over a century of operations, AEP has been a pioneer in the development of advanced coal generation technologies, which include many first-in-the-world accomplishments that have set the standard for combustion efficiencies, emissions control, and system performance. A few examples include the first reheat generating coal unit (1924); the first heat rate below 10,000 Btu/kWh at a coal plant (1950); the first natural-draft, hyperbolic cooling tower in the Western Hemisphere (1963); the first combined-cycle operation of a pressurized, fluidized bed combustion plant in the United States (1990); and the first venting of flue gas through a natural-draft cooling tower in the United States (2012).

While AEP's generation portfolio has shifted over the last decade to include more natural gas-fired generation, this year we will complete construction of the country's first ultra-supercritical coal-fired generating unit, the John W. Turk, Jr. Power Plant in Hempstead County, Arkansas. The Turk Plant has thermal efficiency comparable to the current generation of integrated gasification combined cycle (IGCC) units and is better suited to low-sulfur western coals than many common designs of IGCC technology.

Perhaps AEP's most significant contribution in the area of greenhouse gas emission was the completion of a validation scale demonstration of the world's first fully integrated carbon capture and storage project at an existing coal-fired electric generating unit. The Mountaineer Carbon Capture and Storage Project treated a 20-MW slip stream of flue gas from AEP's 1300 MW Mountaineer Plant, removed more than 90 percent of the CO_2, and compressed and permanently sequestered the captured CO_2 into two deep underground formations more than

7,000 feet below the surface of the plant property. The project successfully operated from 2009 to 2011, captured and stored over 37,000 tons of CO_2, and continues post-closure monitoring under the first CO_2-oriented underground injection control permit issued by the State of West Virginia. A second phase of that project, which would have advanced the technology to a 235-MW commercial scale, was deferred due to the reluctance of our state regulators to impose the significant cost of further technology development on our ratepayers.

Notwithstanding AEP's lengthy history of environmental conservation and support for federal greenhouse gas reduction efforts, AEP cannot support EPA's proposed GHG NSPS for EGUs. As outlined below, EPA's proposed rule is unlawful, is based on faulty information, and would hinder the very efforts to develop clean coal technology that Congress, EPA, and AEP have worked so long and hard to advance. AEP is particularly concerned that the proposed rule will "freeze" carbon capture and storage (CCS) technology development at its current pre-commercial state and hinder the kind of progress that would allow coal to continue to play a vital role in America's energy policy. A detailed report of the current state of CCS technology is included in these comments, which supports EPA's conclusion that no finding can be made that CCS is an available and affordable control technology, and therefore no standard can be established that would require CCS for compliance for coal-fired utility units. For the reasons explained below, EPA should withdraw the proposed rule, or limit its scope to combined cycle natural-gas fired EGUs.

II. EPA's Combination of Two Existing Section 111 Source Categories Into a New NSPS Source Category For One Pollutant Is an Arbitrary and Capricious Departure From Prior Agency Practice

Different electric generation technologies have always had different § 111 standards that could be met in a practical way. Indeed, where appropriate, EPA has subcategorized based on slightly different technologies and fuels within the steam electric generating unit category to accurately establish standards that can be achieved through application of the "best demonstrated" technologies at a reasonable cost. EPA's proposal, however, dramatically departs from this past practice and sets a dangerous new precedent. Congress authorized EPA to establish new categories of stationary sources only upon making a finding that emissions from that category endanger public health or welfare, and to prescribe standards of performance that reflect the best system of emission reduction applicable to such sources, taking into account the cost of achieving such reduction, any non-air quality and environmental impacts, and energy requirements. Congress did not empower EPA to engage in centralized economic planning or to command particular means of production and prohibit others. EPA makes no express endangerment finding for its proposed new Subpart TTTT, and fails to demonstrate, as it has carefully done in each prior NSPS, that the standards proposed for each regulated pollutant can be achieved by every source subject to the standard on a cost-effective basis.[1]

Congress never intended or authorized the actions that EPA proposes to take in Subpart TTTT, nor has EPA ever previously developed a similar standard. Indeed, in every prior rulemaking where EPA forecasted that currently prevailing market conditions made the construction of new gas- or oil-fired capacity unlikely, EPA decided not to undertake a detailed analysis of the existing standards or any more stringent standards that might be achieved at such units, and concluded there was no reason to modify the existing standards.[2] Yet here, while concluding that no new coal-fired capacity is likely to be built within the next eight years, EPA has proposed a standard that has not been demonstrated at any coal-fired unit, and that EPA itself

[1] See e.g., 62 Fed. Reg. 36,948, 36,952 (July 9, 1997) (EPA can consider establishing a standard based on the cleanest fuel so long as there is a technology which allows other fuels to comply with that limit while providing cost-effective emission reductions).

[2] See e.g., 43 Fed. Reg. 42,154, 42,171 (Sept. 19, 1978) ("EPA did not conduct a detailed study of combustion modification or NO_x flue gas treatment for oil- or gas-fired boilers because few, if any . . . are expected to be built in the future.").

admits cannot currently be achieved on a cost-effective basis or without significant energy penalties.[3]

The Clean Air Act is replete with provisions applicable specifically to coal-fired electric generating units, including provisions applicable to new and expanded coal-fired generating capacity. In 1970, 1974, 1977, and 1990, Congress fine-tuned the Clean Air Act to carefully balance the nation's social and economic needs for adequate, reliable, and affordable coal-fired electricity generation with appropriate mitigation of the air quality impacts of such generation. In the past decade, Congress has passed multiple bills designed to advance clean coal technology, thereby cementing coal-fired generation as an important aspect of America's "all-of-the-above" energy policy. Yet, EPA's proposed Subpart TTTT NSPS for GHG emissions from EGUs would impose insurmountable obstacles to new coal-fired generating units as of April 13, 2012, a policy that is nowhere contemplated within the existing Clean Air Act.

Moreover, EPA's protestations notwithstanding, EPA's proposed rule would have severe adverse consequences. Further advancements in coal-fired generation would be suspended, if not totally precluded, by the proposal EPA has issued for GHGs. And, EPA's proposal would do nothing to incentivize further development of CCS technology. Tot he contrary, EPA's proposal would quite likely "freeze" the current state of technology development by discouraging further investment in coal assets. This would be a disastrous outcome for future energy and economic security of the United States.

None of these adverse consequences is necessary. According to EPA, the proposed GHG NSPS for EGUs provides no benefits, because it would simply push potential owners and operators of electric generating units to choose a technology, NGCC, which they are already planning to build in the near-term, due to the current low price for natural gas. And, EPA has acknowledged that it lacks sufficient information to promulgate performance standards for several kinds of sources within its proposed new category, including new sources outside the continental United States and modified and reconstructed sources. EPA should withdraw its proposed rule, or redesignate it as an advanced notice of proposed rulemaking, and proceed with GHG NSPS for EGUs only when EPA has sufficient information to regulate those emissions as the Clean Air Act intended.

---

[3] 77 Fed. Reg. 22,414-415 (April 13, 2012).

A. EPA has not complied with the requirements for publishing categories of stationary sources under Section 111 of the Clean Air Act

Clean Air Act § 111(b)(1)(A) required EPA's Administrator to publish, no later than March 31, 1971, a list of categories of stationary sources that, in the Administrator's judgment, "cause[ ] or contribute[ ] significantly to[ ] air pollution which may reasonably be anticipated to endanger public health or welfare."[4] The Act authorizes EPA's Administrator to "revise" this list of categories "from time to time thereafter."[5] "That provision obviously contemplates an evaluation by the Administrator of the risk that certain types of air pollution will 'endanger' public health and welfare, and the risk that allowing construction of new stationary sources, even subject to existing state and local regulation, will contribute 'significantly' to that air pollution."[6] Following the inclusion of a category of stationary sources on EPA's "cause-or-contribute-significantly" list, the Act directs EPA's Administrator to "publish proposed regulations"; "afford interested persons an opportunity for written comment on such proposed regulations"; "promulgate . . . such standards with such modifications as [the Administrator] deems appropriate"; and then "review and, if appropriate, revise such standards" at least every 8 years.[7]

In this rulemaking, EPA is not following the process outlined in Clean Air Act § 111(b)(1). EPA is not adding a category of new stationary sources to its "cause-or-contribute-significantly" list, or revising existing NSPS to add standards for greenhouse gas emissions. Instead, EPA is proposing to revise the list of categories to add a new category of stationary sources that are already on the list. As EPA acknowledges, the stationary sources that are affected by EPA's new proposed NSPS – "electric utility steam generating units . . . and combined cycle units that generate electricity for sale and meet certain size criteria" – are already included in 40 C.F.R. Part 60, Subparts Da and KKKK.[8] Moreover, EPA is not proposing Subpart TTTT because it made a new "cause-or-contribute-significantly" finding for that category. "EPA has already [separately] determined that both those source categories cause or contribute significantly to air pollution that may reasonably be expected to endanger public health or welfare."[9] It follows that EPA is proposing a new category of "fossil fuel-fired electric

---

[4] 42 U.S.C. § 7411(b)(1)(A).
[5] Id.
[6] Nat'l Asphalt Pavement Ass'n v. Train, 539 F.2d 775, 783 (D.C. Cir. 1976) (footnote omitted).
[7] 42 U.S.C. § 7411(b)(1)(B).
[8] 77 Fed. Reg. at 22,394.
[9] Id. at 22,397.

utility generating units" for purposes other than those contemplated by the Clean Air Act – namely, to ensure that prospective owners and operators of covered electric utility generating units construct natural gas combined cycle (NGCC) units.[10] Because EPA is "rel[ying] on factors which Congress has not intended it to consider," EPA's adoption of a final rule creating a combined, CO_2-specific category of "fossil fuel-fired electric utility generating units" would be arbitrary and capricious.[11]

As EPA recognizes, "combining the Da category and a portion of the KKKK category, and applying as the standard of performance the rate that natural gas-fired EGUs can meet, represents a departure from prior agency practice."[12] EPA acknowledges in the preamble to its proposal that "[b]efore today's rulemaking, the EPA listed different types of fossil fuel-fired EGU's as source categories."[13] EPA has regulated stationary gas turbines under Subpart GG since 1979, and has regulated combined cycle steam/electric generating systems under Subpart KKKK since 2006.[14] It is also a departure from agency practice to have two NSPS categories regulating different air emissions (*i.e.*, criteria pollutants vs. carbon dioxide) from the same stationary source (*e.g.*, a coal-fired electric generating unit). Without a justification for deviating from its past decisions to treat electric utility steam generating units and stationary gas turbines/combined cycle systems as separate categories, and to regulate each kind of stationary source under a single NSPS subpart, EPA's creation of Subpart TTTT cannot pass muster under the requirements of section 307(d) of the Clean Air Act or the analogue provisions of the Administrative Procedure Act.[15]

EPA offers two primary reasons for combining coal-fired boilers from Subpart Da and combined cycle systems from Subpart KKKK for purposes of regulating GHGs.[16] EPA's first stated reason is that it is "reasonable" for "all new fossil fuel-fired electricity generating units that meet specified minimum criteria," and "serve baseload or intermediate demand," to be

---

[10] Id. at 22,392

[11] Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co., 463 U.S. 29, 43, 103 S. Ct. 2856 (1983).

[12] 77 Fed. Reg. at 22,418.

[13] Id. at 22.397.

[14] E.g., 70 Fed. Reg. 8,314, 8,316 (Feb. 18, 2005); 77 Fed. Reg. at 22,397.

[15] See, e.g., F.C.C. v. Fox Television Stations, 556 U.S. 502, 515, 129 S. Ct. 1800 (2009) (holding that an agency changing its policies must "provide reasoned explanation for its action," i.e., "that there are good reasons for the new policy.").

[16] 77 Fed. Reg. at 22,410.

"subject to the same requirements...because they serve the same function[.]"[17] There are several problems with EPA's focus on serving baseload or intermediate demand as a defining characteristic of the stationary sources in the proposed new Subpart TTTT. First, there are no clear, widely accepted definitions of "baseload" or "intermediate" demand. Second, the duty cycle (peaking, cycling, baseload, etc.) of any given electric generating unit may change over time, based on economic, physical, and legal factors. Third, EPA's description of proposed Subpart TTTT is not accurate, as EPA acknowledges that "new sources in non-continental areas" and simple cycle turbines would not be covered by Subpart TTTT, regardless of whether they serve baseload or intermediate demand.[18] EPA also fails to explain the selection of only NGCC and coal-, petcoke-, and oil-fired sources in Subpart TTTT. There are several other kinds of generators in the United States that serve baseload or intermediate demand, including simple cycle gas turbines and biomass-fired generators. EPA included none of them in proposed Subpart TTTT. Fourth, EPA's argument begs the question: **why** is it "sensible to treat as part of the same category units that generate baseload or intermediate load electricity, regardless of their design or fossil fuel type"?[19] Why does the fact that sources from those two categories serve baseload or intermediate load justify combining those sources into a single category for purposes of GHG emissions? EPA does not say.

Instead, EPA answers the opposite question, *i.e.*, why was it **not** sensible to treat as part of the same category units that generate baseload or intermediate load electricity for purposes of regulating **criteria** pollutant emissions? EPA asserts that it was not appropriate to combine Subpart Da and combined cycle units for criteria pollutants because the "array of control options for criteria and air toxic air pollutants" available to coal-fired EGUs "generally do not reduce their criteria and air toxic emissions to the level of conventional emissions from natural gas-fired EGUs."[20] However, coal-fired EGUs also do not have cost-effective, commercially available control options that lower their greenhouse gas emissions to the level of emissions from natural gas-fired EGUs. According to EPA, the most efficient supercritical and ultra-supercritical coal-fired boilers "have CO_2 emissions of approximately 1,800 lb/MWh and provide the lowest

[17] Id. at 22,398.
[18] Id.
[19] Id. at 22,410.
[20] Id. at 22,411.

overall costs for conventional coal-based electricity."[21] While CCS might some day be able to lower the emissions from those boilers to match the emissions from NGCC without CCS, EPA acknowledges the Department of Energy's National Energy Technology Laboratory's estimates that "today's commercially available CCS technologies would add around 80 percent to the cost of electricity for a new pulverized coal (PC) plant."[22] EPA also endorses the findings of the Interagency Task Force on Carbon Capture and Storage established by President Obama (and co-chaired by EPA) that barriers to cost-effective deployment of CCS technology will take years to overcome.[23] While CCS is "technically viable," "full-scale carbon separation and capture systems have not yet been installed and fully integrated at an EGU."[24] Thus, the "array of control options" for coal-fired boilers cannot reduce their CO_2 emissions to the level of emissions from natural gas-fired EGUs that do not have add-on controls. EPA's justification for treating CO_2 emissions from Subpart Da and combined cycle units differently from criteria pollutants from those sources is not supported by the facts.

EPA's second stated reason for combining Subpart Da and combined cycle systems from Subpart KKKK for purposes of regulating GHGs is that "all newly constructed sources have options in selecting their design," and thus "prospective owners and operators of new sources could readily comply with the proposed emission standards by choosing to construct a NGCC unit."[25] Again, this purported justification suffers from several faults. First, this assertion does not explain EPA's decision to create a new category that combines NGCC's from Subpart KKKK with coal-fired boilers from Subpart Da, rather than crafting separate greenhouse gas emission standards for both subparts. Second, EPA's assertion fails to consider the locational impacts of this rule. Power generation decisions are often localized in nature, due to the need to have physical infrastructure to supply fuel and export electricity. For example, the economics of building a coal plant are much different in the middle of a large coal basin with no nearby gas infrastructure, such as the Powder River Basin, than they are in the middle of a gas-producing region with no nearby coal basins. Similarly, there are areas in which CCS cannot be located, such as areas that are seismically active. EPA has already recognized the impact of variability in

[21] Id. at 22,417.
[22] Id. at 22,415.
[23] Id. at 22,414.
[24] EPA, Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units, at 26 (Oct. 2010), available at http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf.
[25] Id. at 22,410.

fuel supply by excluding Hawaii and U.S. territories from its proposed rule. Setting a national CO_2 performance standard without considering locational impacts is not a prudent approach. Third, the argument also overlooks the unprecedented nature of what EPA is suggesting. In the past, owners and operators may have needed to modify the design of a proposed new source to comply with a New Source Performance Standard. Under Subpart TTTT, in comparison, EPA is encouraging owners and operators to build a different kind of source entirely or to employ a control technology that is not commercially available. Section 111 does not empower EPA to manipulate fuel markets, or to pick winners and losers among alternative electric generation technologies. To the contrary – Section 111(b)(5) clearly forbids EPA from dictating that prospective owners and operators must choose a particular technological design in order to comply with a standard of performance (with the exception of work practices or operational standards under Section 111(h), which is not relevant to EPA's proposal).

Picking winners and losers is, transparently, EPA's true purpose here. EPA is not proposing to combine coal-fired boilers from Subpart Da and NGCC's from Subpart KKKK because they serve the same kind of load, because prospective owners and operators of new sources "have options in selecting their design," or because "[c]ombining the categories does not raise adverse policy concerns."[26] EPA is proposing to put NGCC's into a category with Subpart Da stationary sources because it wants to conclude that NGCC's are the "best system of emission reduction" (BSER) for that category.[27] In other words, EPA wants to be able to promulgate a CO_2 NSPS for fossil-fuel-fired electric utility generating units that is based on the CO_2 emissions of an NGCC. EPA admits this when it says that "retaining (and establishing separate standards for) separate source categories...would create the risk of significantly higher GHG emissions and other air pollutants from some new units[.]"[28] Regulating CO_2 emissions from utility boilers under Subpart Da, and CO_2 emissions from NGCC's under Subpart KKKK, would require performing separate BSER analyses for each category, which would result in EPA setting a higher CO_2 standard for utility boilers. In short, EPA decided to create a new, duplicative, combination source category in order to ensure that EPA's BSER analysis would reach the agency's desired and pre-determined result – the effective elimination of coal as an option for future electric generation projects – without regard to statutory instructions.

---

[26] Id. at 22,411.
[27] 42 U.S.C. § 7411(a)(1).
[28] 77 Fed. Reg. at 22,411.

"[S]ection 111 of the CAA...give[s] the EPA substantial discretion to create categories of sources for which standards must be promulgated."[29] That discretion, however, is not unlimited. Agencies must engage in "reasoned decision making."[30] "Reasoned decision making requires an agency to 'examine the relevant data and articulate a satisfactory explanation for its action[s].'"[31] EPA has provided no such explanation. To the contrary – EPA's explanations for its proposed rule are so "implausible that [they] could not be ascribed to a difference in view or the product of agency expertise."[32] Combining sources from two different source categories into a single source category for purposes of regulating greenhouse gas emissions, while maintaining the original separate source categories for purposes of regulating criteria pollutants from the same sources, would be arbitrary and capricious, because it would "rel[y] on factors which Congress has not intended [EPA] to consider" and "run[ ] counter to the evidence before the agency[.]"[33] Consequently, EPA should reverse its decision to combine electric utility steam generating units and combined cycle units into a single source category.

B. EPA has not demonstrated that NGCC is the best system of emission reduction for the proposed category

EPA's proposed Subpart TTTT is also fatally flawed because its proposed selection of natural gas combined cycle (NGCC) systems as the "best system of emissions reduction" does not meet the requirements of Section 111 of the Clean Air Act.

i. NGCC is not a "system of emissions reduction"

Under § 111(a)(1), a standard of performance must "reflect[ ] the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[34] As EPA explained in another rulemaking earlier this year:

---

[29] Davis Cty. Solid Waste Mgmt. v. E.P.A., 101 F.3d 1395, 1405 (D.C. Cir. 1996) (citations omitted).
[30] Judulang v. Holder, 132 S.Ct. 476, 484, 181 L.Ed.2d 449 (2011).
[31] Portland Cement Ass'n v. E.P.A., 665 F.3d 177, 187 (D.C. Cir. 2011).
[32] Motor Veh. Mfrs. Ass'n, 463 U.S. at 43.
[33] Id. See also Judulang at 484 (holding that judicial review of an agency action requires a determination of, among other factors, "whether the decision was based on a consideration of the relevant factors").
[34] 42 U.S.C. § 7411(a)(1).

> The level of control prescribed by CAA section 111 historically has been referred to as "Best Demonstrated Technology" or BDT. In order to better reflect that CAA section 111 was amended in 1990 to clarify that "best systems" may or may not be "technology," the EPA is now using the term "best system of emission reduction" or BSER. As was done previously in analyzing BDT, the EPA uses available information and considers the emission reductions and incremental costs for different systems available at reasonable cost. Then, the EPA determines the appropriate emission limits representative of BSER.[35]

Outside this rulemaking – indeed, in a guidance document currently posted on the section of EPA's website that discusses this rulemaking – EPA has consistently referred to the "best system of emission reduction" as a system of emissions control:

> In determining BDT, EPA typically conducts a technology review that identifies what **emission reduction systems** exist and how much they reduce air pollution in practice. This allows EPA to identify potential emission limits. Next, EPA evaluates each limit in conjunction with costs, secondary air benefits (or disbenefits) resulting from energy requirements, and non-air quality impacts such as solid waste generation. The resultant standard is commonly a numerical emissions limit, expressed as a performance level (i.e. a rate-based standard). While such standards are based on the effectiveness of **one or more specific technological systems of emissions control**, unless certain conditions are met, EPA may not prescribe a particular technological system that must be used to comply with a NSPS. Rather, sources remain free to elect whatever combination of measures will achieve equivalent or greater control of emissions.[36]

EPA has used much the same language to describe the process by which it determines "best system of emission reduction" or "best demonstrated technology" in multiple rulemaking notices.[37]

This is also consistent with how Congress described its intent in creating the New Source Performance Standards. The official summary of the Conference Agreement on the Clean Air Amendments of 1970 stated that "new stationary sources . . . must be controlled to the maximum practicable degree[,]" and "[s]tandards of performance must be set at the greatest degree of control attainable through the application of the best system of emission reduction which has

---

[35] 77 Fed. Reg. 9304, 9423 (Feb. 16, 2012).

[36] EPA, Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act, www.epa.gov/carbonpollutionstandard/pdfs/111background.pdf (emphasis added).

[37] See, e.g., 76 Fed. Reg. 65,653, 65,655 (Oct. 24, 2011); 73 Fed. Reg. 44,354, 44,486-87 (July 30, 2008); see also 70 Fed. Reg. 62,216 (Oct. 28, 2005) (stating, "As with any NSPS analysis, EPA evaluated the controls that effect the best emission reduction of the pollutant in question"); see also, e.g., 44 Fed. Reg. 52,792, 52,797 (Sept. 10, 1979) (concluding, in the final rulemaking for NSPS Subpart GG, that "water injection is considered the best system of emission control for reducing NOx emissions from stationary gas turbines").

been adequately demonstrated[.]"[38]

Here, EPA did not follow its stated practice for determining "best system of emission reduction," as described in its guidance documents and rulemaking notices. Rather than examining available emission reduction systems, EPA states that it "considered a range of natural gas-fired and coal-fired **generation technologies**, with available controls."[39] This is not only inconsistent with EPA's description of its usual practices, it is inconsistent with the explicit text of the statute. An NGCC is not a "system of emission reduction." NGCC is a fuel-specific (i.e., natural gas fuel) generation technology. An NGCC is also a "stationary source," as defined in 42 U.S.C. § 7411(a).[40] In effect, EPA has reached the nonsensical conclusion that the "best system of emission reduction" for a coal-fired steam electric generator is building a different kind of source altogether – a gas-fired combined cycle combustion turbine.[41]

Sec. 111(b)(5) of the Clean Air Act generally prohibits the Administrator from requiring any new source "to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance."[42] EPA has effectively admitted that it crafted the proposed Subpart TTTT for the purpose of compelling potential owners or operators of electric utility generating units to construct NGCC units. At the very least, it has chosen as a "best system of emission reduction" a stationary source that is not a "system of emission reduction." Because an agency may not promulgate a rule that is outside "the scope of the authority delegated to the agency by the statute," EPA's proposed selection of NGCC as the "best system of emission reduction" for its proposed Subpart TTTT would be unlawful.[43]

---

[38] ___ Cong. Rec. S. 20601 (Dec. 18, 1970) (Summary of the Provisions of Conference Agreement on the Clean Air Amendments of 1970).
[39] 77 Fed. Reg. at 22,417 (emphasis added).
[40] See, e.g., 71 Fed. Reg. 38,482, 38,483 (July 16, 2006) (finalizing the NSPS for stationary combustion turbines, which include NGCC's); see also proposed 40 C.F.R. § 60.5580 (defining "electric utility steam generating unit" to include "stationary combustion turbine[s]," which is in turn defined to include "combined cycle combustion turbines").
[41] See 77 Fed. Reg. at 22,410 (stating that the fact that "prospective owners and operators of new sources could readily comply with the proposed emission standards by choosing to construct a NGCC unit" justifies the combination of sources from Subparts Da and KKKK).
[42] 42 U.S.C. § 7411(b)(5).
[43] Motor Veh. Mfrs. Ass'n, 463 U.S. at 42.

ii. EPA's justifications for selecting NGCC as the "best system of emission reduction" are not supported by logic or the facts

EPA's selection of NGCC as BSER also is not supported by its asserted justifications. EPA says that its selection of NGCC as the "best system of emission reduction" is warranted for two reasons: "the emissions benefits" and "the changed economic circumstances, notably the lowered prices of natural gas due to technological development and recent discoveries that have boosted recoverable reserves."[44] Neither reason is supported.

As to the "emissions benefits," EPA projects zero emissions benefits between now and 2030 from including coal-fired EGU's in the proposed Subpart TTTT source category. EPA says its "IPM model does not project construction of any new coal-fired EGUs during [the analysis period for this rulemaking,]" and that its "IPM modeling...projects that there will be no construction of new coal-fired generation without CCS by 2030."[45] EPA admits that "this proposed rule...will not have direct impacts on U.S. emissions of greenhouse gases under expected economic conditions."[46]

As to the "changed economic circumstances" of "lowered prices of natural gas," economic forecasting of future commodity prices is not a relevant consideration for setting performance standards under section 111(a)(1). Nor is speculation about the relative prices of natural gas and coal a decade or more from now.

EPA has "relied on facts which Congress has not intended it to consider" and "offered an explanation for its [proposed rule] that runs counter to the evidence before the agency."[47] EPA has not adequately demonstrated that the selection of NGCC as the best system of emissions reduction is justified, and consequently promulgation of proposed Subpart TTTT by EPA would be arbitrary and capricious.

---

[44] 77 Fed. Reg. at 22,418.
[45] Id. at 22,394 - 22,395.
[46] Id. at 22,401.
[47] Motor Veh. Mfrs. Ass'n, 463 U.S. at 43.

C. EPA's proposed Subpart TTTT raises adverse policy concerns

Lastly, EPA asserts that combining sources in Subpart Da with NGCC systems from Subpart KKKK, and then selecting NGCC as the "best system of emission reduction" for the combined category, "does not raise adverse policy concerns."[48] AEP strongly disagrees.

i. EPA's proposal would trigger PSD program obligations

This rulemaking would, for the first time, make CO_2 a "regulated pollutant" for purposes of the Prevention of Significant Deterioration program. Under EPA's PSD regulations, "regulated NSR pollutant" is defined to include, among other things, "[a]ny pollutant that is subject to any standard promulgated under section 111 of the Act" and "[a]ny pollutant that otherwise is subject to regulation under the Act as defined in paragraph (b)(49) of this section."[49] Through the Tailoring Rule, EPA revised the definition of "subject to regulation" to exclude greenhouse gases, including CO_2, for PSD purposes, except where new sources' and modifications' greenhouse gas emissions exceed certain thresholds.[50] EPA did not, however, exclude greenhouse gases from the definition of "pollutant...subject to any standard promulgated under section 111 of the Act." Consequently, if EPA promulgates the proposed Subpart TTTT, CO_2 will be a regulated NSR pollutant. EPA acknowledged this problem, but stated that comments in the preamble to EPA's Tailoring Rule made clear that EPA did not intend to trigger PSD for CO_2.[51] While this may be true, "language in the preamble of a regulation is not controlling over the language of the regulation itself[.]"[52] EPA also asserted that it had included a provision in its proposed rule that would "revise the NSPS regulations...to explicitly make clear that the NSPS trigger provision in the PSD regulations incorporate the Tailoring Rule thresholds."[53] The proposed revisions to 40 C.F.R. Part 60 listed at the back of the proposed rulemaking, however, include no such provision. Thus, the exact same dire consequences that EPA found to be "absurd" in the Tailoring Rule would be recreated by this rulemaking.

---

[48] 77 Fed. Reg. at 22,411.
[49] 40 CFR 52.21(b)(50)(ii) and (iv).
[50] See generally 75 Fed. Reg. 31,514 (June 3, 2010).
[51] See 77 Fed. Reg. at 22,429.
[52] Wyoming Outdoor Council v. U.S. Forest Service, 165 F.3d 43, 53 (D.C. Cir. 1999), citing Jurgenson v. Fairfax Cty., Va., 745 F.2d 868, 885 (4th Cir. 1984).
[53] 77 Fed. Reg. at 22,429.

ii. EPA's proposal would eliminate new coal-fired generation

EPA's proposal also has the practical effect of eliminating new coal-fired electric generation from State and national energy policy options. It does so by conditioning the construction of new coal-fired electric generating units on the use of technology that is not commercially available, and by the timing and magnitude of increased regulatory costs pinpointed uniquely on coal-fired generation. The proposal effectively forbids construction of new coal-fired generating units without CCS (or some presently unknown alternative technology for reducing power plant CO_2 emissions). CCS technology, if capable of reducing CO_2 emissions on a sustained basis, and if able to navigate the web of unresolved legal and policy issues associated with pore space ownership, long-term liability, and potential for migration across state boundaries within a single storage reservoir, has been estimated to add 80% to the cost of electricity from an ultra supercritical coal-fired generating unit equipped with state-of-the-art emission controls for conventional pollutants just for the capture operations, according to the Department of Energy (DOE)'s National Energy Technology Laboratory.[54] By comparison, EPA's proposed rule would add nothing to the cost of natural gas-fired NGCC technology.

EPA states that it "expects" that "funding for CCS through pilot or other demonstration programs" will continue and that the cost of CCS will decline.[55] That "expectation" is not grounded in facts. The Congressional Research Service recently reviewed DOE's CCS research programs, and found that since those programs began in 1997, and even with the infusion of significant additional funding in 2009 under the American Recovery and Reinvestment Act, "there are no commercial ventures in the United States that capture, transport, and inject industrial-scale quantities of CO_2 solely for the purpose of carbon sequestration."[56] The report concluded that "[t]he challenge of reducing the costs of CCS technology is difficult to quantify, in part because there are no examples of currently operating commercial-scale coal-fired power plants equipped with CCS. Nor is it easy to predict when lower-cost CCS technology will be available for widespread deployment in the United States."[57] Indeed, the report acknowledges that, based on comparative studies of the development of other environmental technologies, "the farther away a technology is from commercial reality, the more uncertain is its estimated cost.

---

[54] 77 Fed. Reg. at 22,415.
[55] Id. at 22,411.
[56] Carbon Capture and Sequestration: Research, Development, and Demonstration at DOE, CRS Report 7-5700 (April 23, 2012).
[57] Id. at p.4.

At the beginning of the R&D process, initial cost estimates could be low, but could typically *increase* through the demonstration phase before decreasing after successful deployment and commercialization."[58] CRS concluded that DOE is just now initiating work on the first commercial-scale projects for CCS, and large-scale demonstration and deployment will not be ready until 2020.[59] Given that further *increases* in costs could occur during the large-scale development and deployment after 2020, and that half of the large-scale projects in the utility sector have been cancelled or substantially altered, EPA's expectation appears to be not much more than wishful thinking. A thorough discussion of the current state of CCS technology based on AEP's own experience is included in Part IV of these comments.

EPA may not set new source performance standards "solely on the basis of...'crystal ball inquiry.'"[60] It is bad policy to so needlessly and severely constrain the energy, economic, and security interests of the United States and the several States based on a snapshot of fuel prices as of April 13, 2012, and the fledgling efforts of an R&D program that has not yet produced a commercial-scale operation.

Subjecting new coal-fired electric generating units to a performance standard set for NGCC units, coupled with the cascade of other recent EPA rules that singularly increase the capital and operating cost of coal-fired generation (the MATS Rule, CSAPR, the GHG BACT rules, the proposed 316(b) rules, CCR management rules under the Resource Conservation and Recovery Act (RCRA), and the impending implementation and revision of the SO_2, $PM_{2.5}$, NO_x, and ozone NAAQS), effectively guarantees a decisive economic advantage to natural gas over coal as a fuel for new dispatchable generating capacity due not to markets, but rather to EPA rulemaking policies. Various studies and projections have concluded that this collection of EPA rules will accelerate the economic obsolescence of approximately 40-100 GW of existing coal-fired electric generating capacity (4,600 MW in AEP's eastern system alone between 2012 and 2017), or 15-30% of the nation's dispatchable coal-based generation resources. Much of that capacity will need to be replaced within the next few years, even without any growth in demand for electricity. Under EPA's proposal, NGCC will be the only option for replacing the coal-fired generating capacity made uneconomical by EPA's rules. The expected surge in demand for natural gas due to regulatory policy, at the same time regulatory policy eliminates coal as an

[58] Id. at p.6 (emphasis added).
[59] Id. at p.23.
[60] Essex Chem. Corp. v. Ruckelshaus, 486 F.2d 427, 433 (D.C. Cir. 1973) (citation omitted).

alternative to natural gas for new electric generating units, is bound to increase costs to electric consumers and raise the price of natural gas for consumers and companies outside the electricity sector. EPA's assumption that "the proposed rule will not impose costs by 2030" is not credible.[61]

The drastic disruption of competitive fossil fuel markets proposed by EPA also conflicts with Congressionally-enacted national energy policies and impairs State social and economic interests. Congress has repeatedly endorsed coal-fired generation and energy diversity. For example, then-EPA Administrator Douglas M. Costle wrote in 1979 that "one of the basic purposes of the 1977 Amendments" to the Clean Air Act was "encouraging the use of higher sulfur coals" and "domestic coal reserves."[62] More recently, the 2005 Energy Policy Act promoted a national investment to advance the "efficiency, environmental performance, and cost competitiveness" of coal-fired generation and "promote...energy security, diversity, and economic competitiveness benefits that result from the increased use of coal[.]"[63] The Emergency Economic Stabilization Act of 2008 extended tax credits for producing electricity from wind, biomass, solar energy, hydropower, and other sources, but also allowed a "30% investment tax credit rate for advanced coal-based generation technology projects" and coal gasification projects and created a new tax credit for CO_2 sequestration.[64] Congress has also acted to shelter local and regional economic interests from the potential effects of environmental regulation. The Clean Air Act authorizes state governors, the Administrator, and the President himself (or his designee) to protect communities from "significant...economic disruption or unemployment" that might result "from using fuels other than locally or regionally available coal or coal derivatives to comply with implementation plan requirements."[65] By moving forward with this rulemaking, EPA would undermine and violate these longstanding Congressional policies.

"The language of section 111...gives EPA authority when determining the best technological system to weigh cost, energy, and environmental impacts in the broadest sense at the national

---

[61] 77 Fed. Reg. at 22,395.
[62] Douglas M. Costle, New Source Performance Standards for Coal-Fired Power Plants, 29 J. AIR POLLUTION CONTROL ASS'N 691-92 (1979).
[63] 2005 Energy Policy Act, §§ 402(a) and 421 (promulgating 42 U.S.C. §§ 15962 and 13571-13574); see also U.S. Dept. of Energy, Clean Coal Technology & The Clean Coal Power Initiative, www.fossil.energy.gov/programs/powersystems/cleancoal/.
[64] H.R. 1424, 110th Cong. (2008), CRS Summary.
[65] 42 U.S.C. § 7425(b).

and regional levels [.]"[66] EPA's selection of NGCC as BSER ignores the vast cost and energy impacts that that choice would create. For these reasons as well, EPA should withdraw its proposal, as its application to coal-fired steam electric generating units would conflict with and undermine Congressional efforts to increase energy diversity and protect local coal-based economies.

III. EPA Must Provide Adequate Assurance That Its Proposal Will Not Affect Existing Sources

EPA must provide an expanded assurance that this rulemaking for new sources rule will not be applicable to and will not affect existing sources.

A. The proposed NSPS does not apply to modified or reconstructed sources

EPA devotes less than two pages of the preamble to an explanation of the interrelationship between this NSPS and modified, reconstructed, or other existing sources currently subject to Subparts Da and KKKK.[67] Nothing in those two pages explains EPA's legal basis for adopting a standard that applies to only a portion of the sources subject to regulation under Section 111(b). While AEP agrees that EPA does not have sufficient information to regulate existing sources in either of the current Subparts, that lack of information simply illustrates the infirmity of the analysis EPA has performed in developing its "new source" standard.

In the development of prior NSPS standards, EPA has relied on a robust set of data from newly permitted sources within a source category to demonstrate that the performance of a particular system or set of technologies is available at a reasonable cost for both newly constructed and modified or reconstructed sources. That is, EPA relied on actual operating data to demonstrate that the standard is demonstrated and the cost of implementing the standard is reasonable.

No similar set of analyses could be undertaken in support of this standard. No examples are cited where an operating fossil fuel-fired unit of any type was modified in order to achieve the proposed standard, nor has EPA identified any technologies that could be applied to any

[66] Sierra Club v. Costle, 657 F.2d 298, 330 (D.C. Cir. 1981).
[67] 77 Fed. Reg. at 22400-22401.

existing unit that would allow it to achieve the proposed standard. Were EPA to undertake such an analysis, it would find that achievement of the proposed standard is infeasible. Even in a case where proposed changes to an existing source exceed 50% of the cost of an entirely new unit, the proposed standard would require building a new NGCC from the ground up.

B. The proposed NSPS is not a BACT floor

In addition to the need for greater clarity on the treatment of "modified" and "reconstructed" sources under Section 111, EPA must provide greater regulatory certainty that this NSPS will not be relied upon to drive fuel and technology choice in the Prevention of Significant Deterioration (PSD) program. EPA claims that its proposal does not amount to a mandate of any particular choice of technology and fuel, but currently, EPA's guidance document on PSD permitting for GHG notes that

> "To the extent EPA completes an NSPS for a relevant source category, BACT determinations that follow will need to consider the levels of the GHG standards and the supporting rationale for the NSPS."[68]

> "While this guidance is being issued at a time when no NSPS have been established for GHGs, permitting authorities must consider any applicable NSPS as a controlling floor in determining BACT once any such standards are final." [69]

If EPA intends to deviate from this practice, it must provide a legal and technical justification that will withstand scrutiny by a reviewing court and can be relied on by state permitting authorities. This guidance document should be updated and made available for public comment to ensure that the guidance aligns with the provisions in the final NSPS to ensure that existing sources that trigger the Tailoring Rule requirements are not subject to a standard applicable to new sources. Any final NSPS for new sources must not establish the BACT floor for existing source projects that are applicable to the PSD permitting program, because EPA has not justified such a standard or conducted an adequate analysis to support such a program. Although EPA has noted that:

> "CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other

[68] U.S. EPA. "PSD and Title V Permitting Guidance for Greenhouse Gases." March 2011. p. 21.
[69] Id. p. 64.

GHG controls. Even if not eliminated in Step 2 [Technical Feasibility Analysis] of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 [Economic, Energy, and Environmental Impacts Analysis] of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible."[70]

EPA also notes that "CCS should be listed in Step 1 of a top-down BACT analysis for GHGs. This does not necessarily mean CCS should be selected as BACT for such sources." p.32 In part because of the position that the technical feasibility and cost-effectiveness challenges will be difficult to overcome, EPA's guidance suggests that CCS will not be BACT:

> "While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases."[71]

> "We expect many permits issued after January 2, 2011, to initially place more of an emphasis on energy efficiency, given the role it plays in affecting emissions of GHGs."[72]

The logical conclusion to draw from the analysis presented by EPA is that no NSPS is practicable at this time, at least for those sources in Subpart Da. Such a results would more closely conform to the available data, and be consistent with past practice. Given the existing guidance EPA has issued, such a result would allow CCS to continue to be considered as part of the technology review in BACT analyses, without burdening sources with the inevitable challenges that will result from EPA dramatically different approach in developing this NSPS. However, if EPA maintains the structure as proposed, a sound legal justification and fuller factual predicate for the conclusion EPA has reached, that the proposed standard has no applicability to existing sources, must be clearer and adequately justified before the rule is finalized.

---

[70] U.S. EPA. "PSD and Title V Permitting Guidance for Greenhouse Gases." March 2011. p. 42-43. www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf
[71] Id. p. 36
[72] Id. p.45.

IV. EPA's proposed rule is based on faulty data

Additionally, EPA's methodology for assessing the costs and benefits of this proposed rule is incomplete and factually disconnected from scientific and economic realities. EPA acknowledges that "ideal benefit-cost analysis would first model projected generation capacity and capacity additions for every plausible set of market conditions[.]"[73] However, EPA did not conduct this analysis. Instead of a robust scenario analysis, EPA relied upon hypothetical examples and illustrations. Policymakers and the public need to be fully informed of the potential costs of this proposed rule. A more detailed scenario analysis needs to be performed using the best available data.

A. Cost analysis

EPA's erroneous conclusion that this policy will have negligible costs or impacts on society is based on the flawed premise that no new coal plants will be built absent this rule. This finding is incorrect for several reasons.

First, EPA acknowledges that there are a number of existing projects for coal-fired power plants that have not yet "commenced construction," but that are well along in the permitting process and have made significant investments. EPA proposes to treat these projects as a special category of "transitional" plants that will not be subject to the standards if they commence construction within 12 months of the date of the proposal. EPA makes no effort to examine the feasibility or cost of any one of these plants actually complying with the proposed standard. EPA also arbitrarily examined the costs of the rule only through 2020. This is a significant and glaring error, in that electric generation facilities typically have life spans of 40 years or more. An appropriate assessment of the cost of the policy would use a similar time span.

Second, new baseload generating capacity takes a number of years to plan, permit, engineer and construct. Even assets coming online after 2020 will have to be planned within the next few years and will be subject to this proposed standard. EPA argues that the fact that it is required to review the NSPS within eight years renders post-2020 analysis irrelevant. However, many potential plants planned **before** 2020 and subject to the NSPS won't come on line until

[73] EPA, Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units ("RIA") at 5-27 (Mar. 2012).

after 2020. Thus, EPA's conclusion that the proposal imposes no costs and has no impacts on society is baseless.

Third, truncating the analysis based on a presumed future is at odds with previous EPA assertions that it will not speculate on future rulemakings in its modeling efforts. EPA states in the documentation for the IPM results that the base case represents "a projection of electricity sector activity that takes into account only those Federal and state air emission laws and regulations whose provisions were either in effect or enacted and clearly delineated at the time the base case was finalized."[74]

Fourth, while EPA has recently promulgated or proposed rules that will collectively increase the cost of coal-fired generation, a disguised regulatory agenda that effectively bans new coal-fired generating units is not a valid reason to consider the NSPS proposal costless. Finally, the modeling of costs only until 2020 is inconsistent with the notion that new coal-fired facilities have the ability to average emissions over a 30-year timeframe.

Equally troubling is EPA's reliance upon a single point forecast of projected new generation using coal and natural gas prices that run out to only 2020. It is impossible to say that new coal-fired generation is not going to be cost-effective in the future based on a single modeled outcome or without considering potential coal and gas prices in the post-2020 time period. Other scenarios recently developed by EPA and EIA indicate that, under different market conditions, new coal units may in fact be built post-2020.[75] However, EPA made no effort to quantify the impacts of these alternative scenarios, due to the arbitrarily truncated period for which it chose to analyze cost impacts. Costs for alternative scenarios should be quantified going forward.

Trends in planned and projected generation tend to oscillate substantially, due to the volatility in fuel commodity markets. As an example, only four years ago, in the 2008 Annual Energy Outlook, EIA forecast 89 GW of new unplanned coal additions by 2030. Just six years ago, in the 2006 Annual Energy Outlook, EIA forecast 145 GW of unplanned coal additions. Immediately prior to those forecasts, however, there was an unprecedented build-out of new natural gas combined cycle capacity, with the belief that those facilities could displace coal. Thirty years prior to the natural gas build-out, there was a similar boom with nuclear power,

[74]www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter1.pdf.
[75]See www.epa.gov/airmarkets/progsregs/epa-ipm/proposedEGU_GHG_NSPS.html, and www.eia.gov/oiaf/aeo/tablebrowser/.

accompanied by the prediction that nuclear energy would be "too cheap to meter." These previous forecasts and historical build cycles illustrate that future generation options and projections are extremely sensitive to future commodity pricing, regulatory requirements, and external events. A myopic view of these influences leads to wasteful and disruptive boom and bust cycles in generation development.

The electric utility industry is currently in a unique period in which material (*e.g.*, steel and concrete) and fuel costs for coal-fired generation have seen dramatic increases at the same time that natural gas prices have reached record lows not seen in the past decade and the demand for electricity has been suppressed due to the prolonged recession and benign weather. However, many analysts expect natural gas prices to rise significantly in the future, as the near term glut of natural gas eventually dissipates. Indeed, the MATS rule and CSAPR rule will force retirement of otherwise economical coal-fired capacity that, under EPA's April 13, 2012 proposal, can only be replaced with NGCC technology, which will sharply increase natural gas demand in a compressed time period. In short, current natural gas prices are as low as they are due to short-term phenomena. Those low prices cannot be expected to be sustained over the long term.

Natural gas pricing has historically been extremely volatile and is the largest determinant of what type of new electric capacity will be built, due to its strong correlation with power pricing. EPA's RIA states on page 4-21 that:

> The natural gas market in the United States has historically experienced significant price volatility from year to year, between seasons within a year, and can undergo major price swings during short-lived weather events (such as cold snaps leading to short-run spikes in heating demand). Over the last decade, gas prices (both Henry Hub prices and delivered prices to the power sector) have ranged from $3 per mmBtu to as high as $9 on an annual average basis.

AEP agrees with this statement and notes that international natural gas prices also have historically experienced seasonal and annual volatility that have resulted in significant spikes for periods of time. The extreme volatility in natural gas pricing should lead to the logical conclusion that structuring the cost benefit/analysis for this rule on a single gas forecast extending through only 2020, with prices at their lowest levels in fifteen years, is not a rational or prudent approach. Thus, multiple natural gas price trajectories should be examined in conjunction with the cost analysis for the rule.

While EPA did examine the role that somewhat higher electricity sales and lower yields from shale gas could have on new capacity decisions, there are other factors that could have even more dramatic impacts on natural gas pricing and new build economics. For example, a move to gas liquefaction and export within either the United States or Canada has the potential to drive up domestic natural gas prices to levels seen internationally, which can be 3 to 4 times higher than current domestic prices.[76] EPA's IPM model does not take into account the development of these facilities, even though announced facilities and current market conditions suggest they will be developed. Additionally, a drop in world oil prices could slow down oil and natural gas liquids production activities, reducing the supply of associated gas and increasing the price of natural gas. Furthermore, EPA's economic modeling to date has not appropriately assessed the impacts of the final MATS rule and other pending regulations, which will lead to the retirement of many coal-fired generating units, further increasing the demand and hence the price for natural gas. The associated reduction in coal use will also influence coal pricing (and reduce coal prices), making new coal fired generation more viable economically. Notably, when spreads between gas and coal prices reach approximately $4 per mmBtu, baseload coal plants become economic to build relative to combined cycle gas plants. Historically there have been many periods where these spreads have existed between gas and coal prices, such as the period from 2003 to 2008. Thus, shale gas recovery levels are only one of multiple factors that could influence natural gas pricing. A broader range of scenarios needs to be explored within the cost-assessment. For each scenario, the cost of this regulation should be assessed, using at least a 30 year time horizon.

B. Selection of 1,000 lb CO_2/MWh emission rate

EPA makes the broad assumption that new Natural Gas Combined Cycle ("NGCC") units can meet its proposed standard of performance, which is 1,000 lb CO_2/MWh of electricity generated on a gross basis. However, a recent study has indicated that many smaller plants will not be able to meet this standard.[77] Additionally, even efficient units could have trouble meeting

---

[76] Richard Bass and Gordon Pickering, *The U.S. Has a Natural Gas Glut; Why Exporting It As LNG Is A Good Idea*, ENERGY SOURCE (June 13, 2012), http://www.forbes.com/sites/energysource/2012/06/13/the-u-s-has-a-natural-gas-glut-why-exporting-it-as-lng-is-a-good-idea.

[77] See Matthew J. Kotchen and Erin T. Mansur, How Stringent is the EPA's Proposed Carbon Pollution Standard for New Power Plants?, at 9 (Apr. 25, 2012), available at http://www.dartmouth.edu/~mansur/papers/kotchen_mansur_co2standards.pdf (finding that "71 percent of the

the standard if gas prices should increase, changing the duty cycle of the units and creating additional inefficiencies associated with cycling or ramping of output. EPA should include in its modeling the additional costs of having to build larger and more efficient units to cope with temporary, intermittent, or unexpected operating conditions. EPA should also conduct a detailed analysis of the effect of unit cycling on meeting the standard. If units must be forced to run even if their cost of operation exceeds the power price in order to meet the efficiency standard, the increased operational cost should be considered in the cost analysis.

C. IPM modeling

In addition to the fundamental flaws in the cost analysis, EPA also made several critical errors in its development of the IPM model and runs used in support of the cost analysis. One major flaw in the IPM model is the double counting of CO_2 risk exposure. As stated in the RIA on page 5-15, "both EIA and EPA include a capital charge rate adder (3 percent) for new conventional coal-fired generating capacity without CCS, which reflects the additional cost of raising capital that is currently reflected in the marketplace, related at least in part to uncertainty surrounding future greenhouse gas emission reduction requirements." Because this proposed NSPS removes much of the uncertainty regarding GHG emission reduction requirements by setting a standard, this penalty should be reduced or removed altogether in the modeling of the reference case for comparison purposes. The use of this penalty in the reference case is an inappropriate bias against new coal generation.

EPA's model is also flawed due to its misrepresentation of compliance planning decisions within the electric sector. For example, EPA's projections for unit retirements due to the CSAPR and the MATS Rule are significantly below what industry has already announced in response to these rules.[78] This is due in large part to EPA's failure to model other pending regulations that could affect electric generators, including Coal Combustion Byproducts (CCB), 316(b) water regulations, regional haze, and potential CO_2 regulations. Due to EPA's failure to consider the impacts of these regulations under development, in contrast to the broader view utilities must take in their compliance planning, EPA vastly underestimates the amount of new

---

[combined cycle gas turbine] units scheduled to come on line through 2017 would have CO_2 emission rates that meet the target").

[78] www.americaspower.org/sites/default/files/may-issuespolicies/Coal-Retirements-Talking-Points-and-Table-April-28.pdf.

electric generating capacity that will need to be brought online over the next decade. Should natural gas units be the preferred generating technology, the impact of the new capacity on natural gas pricing and infrastructure build out requirements also needs to be modeled within IPM as well.

The IPM model also uses outdated capital cost inputs associated with new generation sources. EPA estimates that new natural gas combined cycle generation will cost $976/kW in 2007 dollars.[79] This is substantially lower than estimates by the Electric Power Research Institute (EPRI), the leading not-for-profit research arm of the electric utility industry, of $1275–1375/kW in 2010 dollars.[80] Even correcting for inflation, EPA's capital cost is ~20 to 25% lower than EPRI's estimate. Conversely, EPA projects that a new pulverized coal plant will cost $2,918 – $3,008/kW, in comparison to EPRI's cost of $2,400 – $2,760/kW. In this case, EPA's cost of new coal generation is ~15 to 30% higher than EPRI's estimates. In both cases, these flawed cost estimates artificially bias the model to new gas generation in lieu of coal generation by overstating the cost of coal capacity and understating the cost of gas capacity. This discrepancy should be corrected within IPM going forward.

D. Levelized cost analysis

The levelized cost of electricity projections developed by EPA and cited from EIA within the RIA also present a fundamentally flawed perspective as to the relative cost of new generation. The United States operates an interconnected grid in which generators dispatch on variable cost, with lower cost sources dispatching more frequently. Over the long run, coal generation will dispatch more frequently than gas generation due to lower fuel and variable operating costs. Thus, EPA and EIA's assumption that new coal units and new natural gas units will have the same or similar operation and capacity factors is incorrect. EPA should revise the levelized calculations to include more reasonable assumptions for natural gas plant operation in the IPM, including examining the average capacity factor of new units operating over their first 20 years of operation, particularly in light of increasing state renewable energy requirements requiring increased cycling of other generating assets.

---

[79] www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter4.pdf.
[80] EPRI, Program on Technology Innovation: Integrated Generation Technology Options - Technical Update (June 2011).

EPA's misrepresentation of unit capacity factors results in an erroneous calculation of the fixed charges that need to be recovered. Together with the errors in capital cost and coal capital charge rate adder mentioned previously, EPA's statement that "only when gas prices reach approximately $9.60/mmBtu (in 2007 dollars)...[does] new coal-fired generation without CCS become[] competitive"[81] is patently false. In fact, both EPA and EIA models show new coal being built in various sensitivity cases, even though EPA states that "none of the EPA or EIA sensitivities with alternate assumptions for natural gas approach this price level."[82] These new coal builds occur within the model, even given the input errors that create biases against new coal, due to the model correctly calculating the cost of new generation based on actual operation and taking into account the relative escalation of natural gas prices versus coal prices over the life of the plant.

E. Benefit analysis

It is arbitrary for EPA to propose a rule with no substantive quantifiable benefits. As stated on page 5-19 of the RIA, "EPA anticipates that the proposed EGU GHG NSPS will result in negligible CO_2 emission changes, energy impacts" or "quantified benefits." The absence of any benefit confirms that there is no reason to propose the rule, which establishes a de facto ban on coal fired generation across a range of plausible energy futures. Even though there is no scenario in which quantifiable benefits can be calculated, there are massive potential negative impacts from the policy, should coal be effectively removed as a choice for new generation.

EPA ineffectively tries to qualitatively describe two potential tangential benefits that "may" occur, but presents a flawed argument in support of their inclusion. The first "benefit" cited by EPA is that the NSPS provides legal assurance that any new coal-fired plants must limit CO_2 emissions, as the "rule prevents the possible construction of uncontrolled, high-emitting new sources that might continue to emit at high levels for decades[.]"[83] This is a completely flawed argument, as EPA's current regulations address CO_2 emissions from new sources under its Greenhouse Gas Tailoring Rule. The proposed rule simply further constrains new coal-fired units by relying on the performance of natural gas combined cycle technologies to prescribe standards that cannot in fact be achieved at coal-fired units and do not represent best

[81] RIA at 5-17.
[82] Id.
[83] RIA at ES-3.

demonstrated technology for such units. Allowing for further development of alternative approaches to greater CO_2 reductions through the case-by-case analysis required by the Tailoring Rule would foster greater technological development without unnecessarily constraining fuel choice.

The second claimed benefit is that this rule reduces regulatory uncertainty. However, this proposal will create even *greater* uncertainty, in particular due to its novel treatment of existing modified and reconstructed sources. As an example, EPA is relying on its purported authority to promulgate a "new source" standard that does not apply to "modified" units (notwithstanding the controlling definition of "new source" in Section 111(a)(2) of the CAA) during a period when other EPA regulatory initiatives will require existing coal plants to undertake physical and operational changes in order to achieve reductions in criteria pollutant emissions that are known to increase the hourly rate of CO_2 emissions from coal-fired steam generators. EPA claims that such sources will be protected by the "pollution control project" exclusion in 40 CFR § 60.14(e)(5). EPA acknowledges that this exclusion (dating to 1975 in the NSPS program) is similar to a provision subsequently promulgated under the new source review regulations in Part 51, and that the D.C. Circuit Court's decision in *New York v. EPA*, 413 F.3d 3, 40 (D.C. Cir. 2005), invalidated that similar provision in the new source review program. The questionable continuing validity of the pollution control exclusion may well force additional coal unit retirements, beyond the ~53,000 MW already announced, even though EPA has acknowledged that it has insufficient information to develop standards that could apply to existing sources.

Even if a source were willing to undertake such a risk and accept that installation of additional criteria pollutant controls would eventually require the capture and storage or sequestration of CO_2, uncertainty persists regarding the availability of adequate sequestration sites within reach of existing units, the actual performance of available capture technologies, the actual performance of long term sequestration operations, and the long-term regulatory framework for liability. EPA touts the use of DOE funding for CCS projects. However, the DOE has repeatedly pulled funding from its FutureGen project. DOE funding alone has been insufficient to allow half of the award recipients to continue with planned projects and depends upon an appropriation system that is subject to the federal budgeting process. AEP's own experience with a DOE-funded project is discussed in greater detail in Part IV of these comments.

The preamble to EPA's proposal includes a highly speculative section commenting on potential external societal costs relating to various generating technologies. While this section is not intended as a firm calculation of benefits, it presents a biased picture of societal costs and fails to adequately express the uncertainty surrounding the underlying calculations. Furthermore, this analysis is based on the flawed levelized cost of electricity calculations mentioned previously.

For this highly speculative analysis, EPA uses the Societal Cost of Carbon (SCC) developed in 2010,[84] even though it is widely acknowledged that these cost estimates are inaccurate. EPA acknowledges in the RIA that "any effort to quantify and monetize the harms associated with climate change will raise serious questions of science, economics, and ethics and should be viewed as provisional."[85] As such, these calculations cannot form the basis of an adequate RIA.

EPA also presents calculations for NO_x and SO_2 using a benefit per ton reduced standard that suffer from additional flaws. National Ambient Air Quality Standards (NAAQS) are designed to protect health and welfare with an adequate margin of safety. Additional reductions of these pollutants in areas of the country that attain these health-based standards should not have **any** quantifiable health benefit. Additionally, the modeling and calculations presented by EPA ignore the projected impacts of the MATS Rule on air quality, which in many cases will drive emissions below the Lowest Measured Levels (LML) in the studies used to support the health claims, thus invalidating the applicability of the studies to a benefit calculation. Furthermore, the Pope et al. and Laden et al. studies which underpin many of the EPA health benefit estimates[86] are dated pieces, using older air emissions and other data from the 1980s and 1990s that do not take into account current emission levels or trends (which indicate, for example, that air emissions are 3 to 5 times lower than when these studies were conducted). Nor do these older data studies differentiate health response between various species of fine particulate matter even though more recent studies show associations between locally produced carbonaceous compounds but *NO* associations between utility produced SO_2 and NO_x emissions.[87]

---

[84] See RIA, 5-28 through 5-30.
[85] Id. at 5-23.
[86] See, e.g., RIA at 5-30.
[87] Examples include: (1) Grahame TJ, Does improved exposure information for PM2.5 constituents explain differing results among epidemiological studies? Inhal .Toxicol. 21: 381-393 (2009); (2) Lipfert FW, Wyzga RE, Baty JD, Miller JP, Air pollution and survival within the Washington University-EPRI veterans cohort: risks based

Given the acknowledged limitations of the analyses presented, EPA should not include any health benefits within the RIA as any such benefits are indirect and speculative. Furthermore, EPA should update its calculations of health benefits to include the latest scientific literature, which include newer peer-reviewed studies showing no association between PM and mortality and significant issues with the methods used in the Laden et al. study.[88]

V. Carbon Capture and Storage Is Not Commercially Available For Coal-Based Generation and Will Not Become a Viable Control Option Until Significant Challenges Are Addressed

EPA notes that it "does not prescribe a particular technological system that must be used to comply with the standard of performance" and that "sources remain free to elect whatever combination of measures will achieve equivalent or greater control of emissions."[89] Practically speaking, though, CCS is the *only* control option *potentially* available for new coal-based generation to meet the proposed limits. EPA's extensive discussion in the proposed rule of the technical feasibility, commercial status, and availability of CCS exposes the total reliance of the proposed rule on this single technology for compliance by coal-fired EGUs. In fact, EPA notes that "by clarifying that, in the future, new coal-fired power plants will need to implement CCS, this rulemaking eliminates uncertainty about the status of new coal."[90]

The problem with EPA's reliance on CCS is that CCS is not commercially available for coal-based generation and faces significant technical, financial, regulatory, and legal barriers that must be addressed before it becomes a viable CO_2 emission control option. AEP considers "commercially available" technologies as those that can be purchased from a vendor, have been proven at commercial scale on a representative application, and are furnished with robust guarantees on performance and reliability. Based on these criteria, CCS is not commercially available. In fact, at the current pace of development, CCS technology will not be available for *at least* a decade. CCS development barriers and opportunities for addressing them have been identified by numerous private and public efforts (e.g., President Obama's Interagency Task

---

on modeled estimates of ambient levels of hazardous and criteria air pollutants. J Air Waste Manag Assoc., 59(4):473-89 (Apr. 2009); and (3) Grahame T, and Hidy GM, Pinnacles and Pitfalls for Source Apportionment of Potential Health Effects From Airborne Particle Exposure, Inhal .Toxicol. 19: 727-744 (2007).

[88] Graven et al., An Approach to the Estimation of Chronic Air Pollution Effects Using Spatio-Temporal Information, Journal of the American Statistical Association (2011).

[89] 77 Fed. Reg. at p. 22,402.

[90] Id. at p. 22,399.

Force, the Secretary of Energy's National Coal Council, and the Department of Energy's research and development programs); by AEP, through our efforts in operating the first integrated CCS project in the world on a coal-based generation unit; and even by EPA, in the proposed rule and in dealing with air permitting issues for greenhouse gases. The following sections provide an expanded discussion of accumulated knowledge about the development barriers that remain for CCS, and demonstrate that the proposed CO_2 NSPS for coal-based generation is technically flawed because no commercial control options, including CCS, are available now or will be available in the near-term to meet the proposed standard.

Considering the state of the technology, EPA's reliance on the current and predicted near-term availability of CCS as a viable option to meet the proposed NSPS is premature and does not align with the many practical estimates of the expected timeline for developing the technology. EPA's proposed approach effectively precludes future consideration of electric generation options that must rely upon CCS to meet the proposed standard. EPA should establish standards for new coal-based generation that are specific to coal without the use of CCS and that are premised on the best demonstrated efficiencies that have been achieved in practice by advanced coal technologies.

A. Technically feasible is not the same as commercially available

Varying degrees of technical feasibility can be demonstrated based on desktop calculations, laboratory studies, pilot-scale testing, large-scale demonstrations, or other methods. However, a process that is technically feasible is not necessarily commercially viable or available.[91] A determination of commercial availability cannot be made until sufficient research, development, and demonstration occurs that validates the feasibility of the technology at a commercial scale, allows for the optimization of systems integration and performance, and provides for cost-effective design options that can be safely and reliably operated. Absent this development process, a technically feasible process remains just that – only technically feasible and no more. Research and development continues, but CCS has yet to be demonstrated to be commercially available for coal-based generation. The scope of obstacles to commercial availability, coupled with the magnitude of cost and time for addressing them, are significant and have been widely acknowledged.

[91] Technical feasibility, by itself, is insufficient to satisfy the BSER criteria in section 111(a) of the Clean Air Act.

Despite these recognized development short-comings, EPA concludes in the proposed rule that CCS is technically feasible and minimizes any remaining development risks based on a variety of factors including the experience of other industries, conceptual design of CCS systems that have yet to be constructed or demonstrated, and an overly simplistic assessment of the challenges to initial and broader commercialization.[92] EPA suggests that "the cost of CO_2 capture and compression represent the largest stumbling block to widespread commercialization of CCS."[93] EPA also notes that although they "expect the cost of CCS to decline, we [EPA] recognize that the amount of the decrease is uncertain."[94] If magnitude and rate of cost reductions is uncertain, then so are the prospects that the "largest stumbling block" to commercialization has been adequately identified, let alone that it will be sufficiently addressed at *any* point in time for a new source to rely on CCS as a viable control option. While lowering capture costs certainly is a significant challenge, it is only one of many significant challenges that impede the commercial availability of CCS. EPA's focus on capture costs in the proposed rule grossly understates the breadth of barriers to rapid commercial development by minimizing the significant technical challenges that exist for *capture* systems and by overlooking the equally significant technical, cost, and legal challenges with *transport* and *storage* systems, which are discussed in the sections below.

B. Significant technical, financial, regulatory, and legal barriers exist that must be addressed before CCS is commercially acceptable for coal-based generation

Many proponents of limiting CO_2 emissions point to CCS as the primary means of accomplishing this objective. AEP has been a strong advocate for the development and advancement of CCS technologies, as demonstrated by our extensive work at the Mountaineer Plant. Furthermore, AEP believes that technological solutions are critical to reducing emissions from or improving the reliability and availability of electricity production. Nonetheless, as a consequence of our first-hand experience and intimate understanding of the technologies, AEP is

[92] See e.g., 77 Fed. Reg. at 22,415 ("processes....to separate CO_2 from other gases have been in use since the 1930's"); 22,414 ("[EPA's] position is that CCS is a feasible technology option for new coal-fired power plants because CCS is technically feasible and sufficiently available") ; and 22,396 ("new coal-fired power plants with CCS are being permitted and built today").
[93] Id. at 22,415.
[94] Id. at 22,419.

convinced that CCS is many years from providing a commercially viable solution to reducing CO_2 emissions.

"Commercially available" technologies are those that can be purchased from a vendor, have been proven at commercial scale on a representative application, and are offered complete with robust guarantees on performance and reliability. Vendors cannot provide meaningful guarantees without extensive testing at representative scale. Based on this definition, there are no commercially available technologies for the capture of CO_2 from coal-based power plants. The Department of Energy's Major CCS Demonstration program currently includes twelve projects that propose to demonstrate CO_2 capture and some form of storage and/or utilization of the captured CO_2.[95] If this were a list of twelve successfully completed projects, then it could certainly be argued that the technologies are ready for commercial deployment. However, not one of the projects has been completed, and in fact, none have even commenced operation. Most are no more developed than the work on paper required for conception of the project. Moreover, some that had previously been included on DOE's list have been cancelled or delayed indefinitely. And, on a global scale, the United States leads all others in work done to date and proposed future projects. Simply put, the technologies to capture and sequester CO_2 are not commercially available today.

While several promising CO_2 capture technologies are being developed, none are ready for commercial deployment; rather, they must be advanced in a systematic and step-wise manner. AEP had begun the process of moving the technology to commercial scale, but the lack of an adequate funding mechanism resulted in the company placing the project on hold. Even if AEP's project had remained on schedule, commercial-scale deployment of the chilled ammonia process in a first-of-a-kind large-scale unit would not be in service before 2015. The AEP unit, like other first-of-a-kind projects, would have been installed without any commercial guarantees from vendors and would have run the risk of not continuously or reliably achieving high CO_2 capture levels. AEP's expectation was that a commercial-scale CCS demonstration project was essential *now*, so that in 2020 or later, a reliable commercial-scale CO_2 capture system *might* be commercially available and ready for deployment. With the suspension of the AEP project and as similar DOE projects are delayed or discontinued, the date for commercial readiness of CCS

[95] See U.S. Department of Energy, National Energy Technology Laboratory (NETL), Major Demonstrations, Industrial Capture and Storage (ICCS): Area 1, www.netl.doe.gov/technologies/coalpower/cctc/iccs1/index.html.

technology continues to move further out on the horizon. A reasonable estimate for commercial availability, based on the current state of technology development and as discussed in Section C. below, is *at least* ten years away, and this is assuming that current financial and regulatory barriers to demonstration projects are immediately removed. Without a clear path forward, we will remain, perhaps indefinitely, *at least* ten years or more from commercialization of CO_2 capture technology.

Besides the time required to demonstrate technology maturity, CCS developers must also tackle numerous technical challenges associated with both CO_2 capture and geologic sequestration. On the capture side, energy demand, physical space requirements, power plant integration, and flue gas compatibility all pose formidable obstacles to overcome. Some of these challenges are summarized below.

- Energy consumption requirements represent the single most daunting barrier to economical deployment.
- The sheer size of the equipment brings its own set of concerns. The current configuration more than doubles the power plant footprint, representing substantial construction challenges and project cost implications.
- Due to the magnitude of energy requirements, integrating these systems into plant designs and process flow schemes provides unprecedented engineering and operations challenges.
- Certain CO_2 capture systems have chemistry requirements that demand pristine flue gas conditions, in some cases well beyond the capability of state-of-the-art flue gas desulfurization ("FGD") and selective catalytic reduction ("SCR") systems.

These four points cannot be addressed merely with paper studies or engineering exercises and specifications. It is critical that solutions to these very real challenges are developed and physically demonstrated, with proven performance at full scale, and exposed to the full gamut of commercial power plant conditions, before operators can consider full-scale technology deployment on commercial electricity generating units.

There also remain many unresolved technical challenges related to CO_2 sequestration and/or utilization. The availability of suitable saline formations, injection pressure limitations, and ultimate storage capacity are all currently the subject of intense study and lack large-scale data for proof-of-concept soundness. Monitoring and verification of the CO_2 plume extent and

assurance of confinement requires technologies that have not yet been proven in representative applications. While help from the oil exploration and production industries is certainly beneficial, there is no substitute for the operation of numerous large-scale demonstration projects involving CO_2 injection into saline and other formations. Geologically-based computer models must undergo time-consuming, expensive, and rigorous validation in order to be proven reliable, so that they can be used in lieu of the exorbitantly high costs of installation of large numbers of monitoring wells. In the near term, Enhanced Oil Recovery ("EOR") projects offer potential opportunities to put captured CO_2 to economical use, but these operations are also faced with substantial challenges associated with validation and accounting for CO_2 storage permanence. Current and past EOR practices have not been required to demonstrate permanent CO_2 storage. In fact, EOR operators have been economically driven to minimize the quantity of CO_2 left underground in favor of reusing it in other recovery operations.

AEP's CCS demonstration program, again, is an example of the systematic nature of these projects, taking the technology in step-wise fashion from small-scale to commercial-scale deployment. The timeline for this work points again toward the need for at least another ten years of development and demonstration for wide-scale application of the technology. In summary, CCS technology is not yet ready for wide-scale and large CO_2 capture mandates. Continued research, development, and demonstration must be supported and is essential to make CCS technologies a reality in the next decade.

Further, the path to CCS commercialization also faces significant regulatory and legal barriers. These include issues related to the ownership of, acquisition of, and/or access to geologic pore space, as well as issues surrounding long-term liability and stewardship of geologically stored CO_2. Resolution of these barriers in many cases will be through the development of state legislation and regulatory programs. Efforts at the state and federal level are underway and at various levels of progress, but significant challenges remain before a variety of legal and regulatory issues may be sufficiently resolved to support the commercialization of CCS on coal-based generation.

C. Numerous public and private organizations have concluded that CCS for coal-based generation is not commercially available and that significant development barriers remain

Numerous studies and projects by public and private organizations recognize that CCS is not commercially available for coal-based generation and that significant development barriers remain. For example, a November 17, 2011 article by Reuters noted that "[EPA Administrator Lisa] Jackson, whose agency looked at CCS as it developed the rules, said the technology has a long way to go. 'It can be years, maybe a decade or more, until we have the technology available at commercial scale,' she said."[96]

While research, development, and demonstration ("RD&D") programs continue, the current scope and pace of these efforts is insufficient to drive the near-term commercial availability of CCS. Results from many of these studies indicate that the availability of commercially available CCS technology is *at least* a decade or more away, *even if* a much more ambitious RD&D program were implemented. Appendix A summarizes some of these studies to highlight the state of CCS technology development and to demonstrate that reliance on the availability of CCS as a viable CO_2 control strategy to meet either the proposed annual or 30-year average NSPS limit is premature.

D. AEP's experience demonstrated both the potential of CCS and the significant challenges that still must be addressed

From 2009 to 2011, AEP operated the first integrated CCS project in the world on a coal-based generation plant. The lessons learned from that effort uniquely position AEP to comment on the potential of CCS technology and the significant remaining developmental challenges that must be addressed before CCS can be considered commercially available. The following summarizes AEP's CCS experience at the Mountaineer Plant, a 1,300 MWe coal-fired generating unit in New Haven, West Virginia.

A number of qualifications must be made in order to properly understand what was and was not accomplished by AEP at the Mountaineer Plant. First, EPA claims that "the AEP Mountaineer project showed that CCS can be successfully retrofitted into an existing plant."[97]

---

[96] www.reuters.com/article/2011/11/17/usa-epa-carbon-idUSN1E7AG0WU20111117.
[97] 77 Fed. Reg. at 22,425.

Taken out of context, this claim is misleading. The term "retrofit" does not mean that a commercial-scale CCS system was constructed and operated at the Mountaineer Plant. AEP successfully deployed a CO_2 capture system on a validation-scale (20-MWe, or 1.5% of Mountaineer's 1,300-MWe) slip-stream process. The success of that project was in proving that the technology was compatible with power plant conditions and that the technology could successfully capture CO_2 at a coal-fired power plant. The project *did not prove* that CCS technology can be successfully operated at commercial scale or that it is commercially available. AEP did consider a commercial-scale project, but after performing a front-end engineering and design ("FEED") study and being unable to obtain necessary cost-recovery approval from regulators, decided to cancel the project.[98] It should be clearly understood that the validation *does not* constitute a commercial demonstration and that the technology *is not* to be considered commercially available.

AEP partnered with Alstom to validate the chilled ammonia process for capturing CO_2 from the Mountaineer Plant. The 20-MWe slipstream system was initially operated on September 1, 2009, and continued through May 31, 2011. Over that period, the chilled ammonia process captured more than 50,000 metric tons of CO_2. Because the system was built as a validation platform, with all the flexibilities necessary for systematic process adjustments, it was not optimized for maximum energy efficiency. This design enabled operators to fine-tune and control all process streams and energy inputs to thoroughly evaluate the technology. Once completed, the AEP/Alstom team developed a comprehensive understanding of the chilled ammonia process and specifics about the operation of each system within the process. This in-depth knowledge, including a detailed understanding of key process parameters such as energy penalty, reagent loss, and CO_2 capture rate, enabled the team to move forward with an engineering study and preliminary design for a commercial-scale deployment at the same power plant.

While the capture process has been shown to be technically feasible under coal-fired power plant conditions, there are many important aspects of the technology that must be demonstrated at full-scale (a minimum of approximately 250-MWe, or more than 12 times the size of the validation system at Mountaineer) before a process supplier or power plant owner can

[98] The Final Technical Report for the commercial scale CCS project can be found at www.netl.doe.gov/technologies/coalpower/cctc/ccpi/bibliography/demonstration/ccpi_aep/MTCCS%20II%20Final%20Technical%20Report%20Rev1.pdf.

realistically consider deploying the technology commercially. For example, chilled ammonia, and any other post-combustion CO_2 capture process, uses enormous quantities of steam to process and recycle the reagent. If the steam is taken from the existing power plant boiler/steam-turbine system, that represents a significant power generation heat cycle change that requires steam path re-design and modification of the generating unit. Once completed, the modifications intrinsically tie together the generating unit with the CO_2 capture system. Such a combination of systems has never been demonstrated and must be rigorously tested and optimized before the technology can be deemed reliable, proven, or commercially viable. In addition, the equipment to capture CO_2 is large and an entire system capable of treating the effluent of a power plant requires extensive tracts of land. In the AEP/Alstom study of a commercial scale installation, the system was designed to capture 265 MWe worth of flue gas (approximately 1/5 of the plant output), yet it occupied a footprint nearly the same size as the original power plant, or about 11 acres. Size alone precludes deployment of the technology at many existing power plants and must be carefully considered in the design of any new power plant.

AEP also partnered with Battelle to study and validate sequestration of CO_2 into deep saline reservoirs near the Mountaineer Plant. Approximately 37,000 metric tons of captured CO_2 were compressed and injected into two saline reservoirs located roughly 8,000 feet beneath the plant site. Besides two injection wells, one into each of the reservoirs, AEP deployed three full-depth monitoring wells at various distances from the injection point. Many experimental and novel technologies were tested at the site. The difficult nature of the geology in the area proved some of these technologies to be inappropriate for the application. Again, while the project was successful in injecting and confining all of the CO_2 sent to the wellheads, the scale was quite small and far from being representative of what would be required for a full scale deployment. Furthermore, there remains great uncertainty surrounding the liability for and future ownership of injected CO_2, which could dissuade any operator from injecting at commercial scale.

In conclusion, it is more accurate to state that the AEP Mountaineer project proves that the technology shows promise for existing or future plant application, but is still many years from being proven at a commercial scale, still requires development of an appropriate regulatory or legal framework, and cannot yet be deemed as commercially viable technology.

E. EPA's rationale is insufficient for concluding that CCS is a feasible control technology option for coal-based generating units

EPA relies on four factors as the basis for their "position that CCS is a feasible technology option for new coal-fired power plants because CCS is technically feasible and sufficiently available in light of the limited amount of new coal-fired construction expected in the foreseeable future."[99] As discussed below, *none* of the four factors described by EPA demonstrates that CCS is commercially available or feasible as a practical matter. In fact, EPA's rationale actually highlights the significant development steps that CCS must take before it can even begin to be considered a viable control option.

i. First EPA basis: The "Technological Feasibility of CCS."[100]

EPA utilizes the findings of President Obama's Interagency Task Force on Carbon Capture and Storage ("Task Force") to assess the current state of CCS technology. The charge of the Task Force was to propose "a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing five to ten commercial demonstration projects online by 2016."[101] The proposed rule notes that the Task Force found that "there are no insurmountable...barriers that prevent CCS from playing a role in reducing GHG emissions." But, as EPA points out, the Task Force also acknowledged that "early CCS projects face economic challenges related to...first-of-a-kind risks" among other factors.[102] In fact, the final report of the Task Force notes that "barriers hamper near-term and long-term demonstration and deployment of CCS technology."[103] In essence, an ambitious near-term research, development, and demonstration program would need to be implemented in order to overcome barriers to the commercialization of CCS. To date, such a program has yet to yield a single operating commercial-scale demonstration project at a coal-based generating unit and is certainly not on pace to achieve the five to ten projects by 2016 that the Task Force recommended for overcoming barriers by 2020.

---

[99] 77 Fed. Reg. at 22,414.
[100] Id.
[101] Id.
[102] Id.
[103] Report of the Interagency Task Force on Carbon Capture and Storage, p. 14 (Aug 2010).

With respect to carbon capture, EPA notes that other industries have captured CO_2 "since the 1930's using a variety of approaches."[104] For EPA to suggest that capture technologies should be readily transferable to coal-based electric generating units because of a long history of use in other industries ignores the multitude of technical, process design, and operational differences between the "industrial gas streams" referenced and a coal-based power plant. It also ignores the significant difference in the quantities and end use of the captured CO_2. The quantities of CO_2 captured from coal-based generating units will be orders of magnitude greater than that for most "industrial gas streams," while the end use for coal-based CO_2 will be for geologic sequestration or enhanced oil recovery processes rather than "to produce food and chemical-grade CO_2."[105]

Additionally, EPA notes in the preamble to the proposed rule that pre-combustion, post-combustion, and oxy-combustion systems are technically feasible. While technically feasible, *none* of these capture systems has even been demonstrated at a coal-based power plant on a commercial-scale as either an independent process or, more importantly, as an integrated process with a CO_2 utilization or geologic storage system.

EPA notes that "the costs of CO_2 capture and compression represent the largest stumbling block to widespread commercialization of CCS."[106] As noted in Section (a) above, EPA's focus on capture costs as the largest barrier is far too narrow and ignores numerous other development risks and barriers to commercial development by minimizing the significant technical challenges that exist for capture system deployment and by overlooking the equally significant technical, cost, and legal challenges with transport and storage systems.

EPA asserts that "the remaining steps for CCS (i.e., pipeline transportation and storage) are well established but less expensive than capture and compression," and that based on the experience of other industries "the transportation component of CCS is not expected to be a significant stumbling block to the commercial availability of CCS."[107] While the U.S. has experience in transporting limited amounts of CO_2 via pipeline and has identified *potential* geologic storage reservoirs, the conclusion that this level of development is sufficient to allay any related concerns about CCS commercialization at coal-based generating facilities is overly

[104] Id. at 22,415.
[105] Id.
[106] Id.
[107] Id.

simplistic. Significant development barriers remain for these aspects of the technology. For instance, the DOE's Carbon Sequestration Program plan has four goals that can be summarized as: (i) reducing CCS related costs, (ii) improving assessments of geologic storage, (iii) developing technologies for evaluating the retention of CO_2 that has been geologically stored, and (iv) completing a best practices manual for site selection, characterization, site operations, and closure practices. DOE notes that "[o]nly by accomplishing these goals will CCS technologies be ready for safe, effective commercial deployment both domestically and abroad beginning in 2020."[108] In summary, EPA's position that the "remaining steps for CCS are well established" ignores the many additional steps required to assure the commercial availability of these technologies for the greatly increased amounts of CO_2 generated by coal-based generating units. EPA also simply ignores the fact that much more development is needed to address the multitude of technical, regulatory, legal, financial, and societal barriers associated with widespread deployment of this technology.

In terms of sequestration, EPA cites four projects around the globe that are capturing and geologically storing CO_2 to indirectly suggest that the technology is readily available for sources to use in complying with the proposed rule. Although these projects further demonstrate the potential of CCS as a control technology, they are insufficient to address the scope of development barriers that remain for CCS to be commercially acceptable for coal-based generation. This is, in part, because these projects are not being demonstrated at a coal-based power plant, and therefore do not address the related technical challenges associated with process integration, or the significant cost barriers for capture systems. Further, the projects do not address the technical, regulatory, and legal barriers to geologic sequestration that impede the development of commercially available CCS for coal-based power generation.

EPA also identifies various regulatory programs that apply to the geologic storage of CO_2, namely the Underground Injection Control Class VI rule, the Greenhouse Gas Reporting Program, and proposed revisions to the RCRA program. EPA notes that "[t]ogether, these actions help create a consistent national framework to ensure the safe and effective deployment of geologic sequestration."[109] These actions are a start, but fall far short of sufficiently resolving the many critical regulatory and legal issues that have been widely recognized as impeding the

[108] Department of Energy / National Energy Technology Lab. Feb 2011. p. 10.
[109] 77 Fed. Reg. at 22,415.

commercialization of CCS. For example, the President's Task Force on CCS concluded that "for widespread cost-effective deployment of CCS, additional action may be needed to address specific barriers, such as long-term liability and stewardship" and that "regulatory uncertainty has been widely identified as a barrier to CCS deployment."[110] The National Coal Council has advised the Secretary of Energy that "[t]he management of long-term liability risks is [a] critical consideration for CCS projects...[U]ncertainty regarding long-term liability options remains a challenge."[111] Further, a 2011 study from the Harvard Kennedy School's Energy Technology Innovation Policy Research Group similarly found that, for the commercial-scale CCS demonstration projects in Phase III of the DOE's Regional Carbon Sequestration Partnerships Program, "[l]iability for sequestration of CO_2 and lack of coordination among regulatory authorities" would pose "significant barriers."[112]

EPA's position on the feasibility and availability of CCS in the proposed rulemaking are in many ways contradictory to its assessment of the technical feasibility, cost-effectiveness, and commercial availability of CCS in the *PSD and Title V Permitting Guidance for Greenhouse Gases* document. Throughout the guidance document, EPA suggests that CCS be considered in a BACT analysis and that CCS will likely not apply because it is not technically feasible and/or because it is not cost-effective - both reasons highlight the fact that CCS is not commercially available. The examples below from the guidance document indicate that CCS will likely not qualify as BACT. If the level of development is insufficient to generally apply CCS as BACT, it is necessarily also insufficient to support the effective use of CCS as a basis for NSPS.

- "While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases."[113]
- "Based on these [technical, cost, logistical, etc] considerations, a permitting authority may conclude that CCS is not applicable to a particular source, and consequently not technically feasible, even if the type of equipment needed to accomplish the compression, capture, and storage of GHGs are determined to be generally available from commercial vendors."[114]

---

[110] Report of the Interagency Task Force on Carbon Capture and Storage, pp. 10-14 (Aug 2010).
[111] Expediting CCS Development: Challenges and Opportunities, p. 83 (Mar 2011).
[112] Craig A. Hart, Putting It All Together: The Real World of Fully Integrated CCS Projects, Discussion Paper 2011-06, Belfer Center for Science and International Affairs (June 2011) available at http://belfercenter.ksg.harvard.edu/files/Hart%20Putting%20It%20All%20Together%20DP%20ETIP%202011%20web.pdf).
[113] U.S. EPA. "PSD and Title V Permitting Guidance for Greenhouse Gases." March 2011. p. 36.
[114] Id.

- "EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 [Technical Feasibility Analysis] of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 [Economic, Energy, and Environmental Impacts Analysis] of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible."[115]

ii. Second EPA basis: "Expected reduction in CCS costs"[116]

The proposed rule states that "DOE/NETL estimates that using today's commercially available CCS technologies would add around 80 percent to the cost of electricity for a new pulverized coal plant, and around 35 percent...for a new advanced...IGCC plant."[117] The statement is pulled directly from the 2010 DOE CCS Roadmap report, but it lacks important context from the report that elaborates that CCS is not yet commercially available. For example, the report notes that the DOE RD&D effort "involves pursuing advanced CCS technology...so that full-scale demonstrations can begin by 2020" in order to "enable broader commercial deployment of CCS to begin by 2030." The report also notes that "advanced technologies developed in the CCS RD&D effort need to be tested at full scale....*before* they are ready for commercial deployment."[118] It is clear from the scope of RD&D identified by DOE, that CCS is not commercially available for coal-based generation. Furthermore, the fact that CCS has been estimated to add 80% to the cost of electricity in and of itself speaks to its lack of commercial viability and the infancy of the technology as a potential emissions control option for coal-based generation.

EPA attempts to address the CCS cost issue by equating the development of CCS to the development of other emissions control technologies. The proposed rule notes that "significant reduction in the cost of CO_2 capture would be consistent with the overall experience with the cost of pollution control technology." Further, "[r]eductions in the cost of air pollution control technologies...have been observed over the decades. We [EPA] expect that the costs of capture

---

[115] Id. at. pp 42-43.
[116] 77Fed. Reg. at 22,415.
[117] Id. at 22,415-22,416.
[118] DOE / NETL CO_2 Capture and Storage RD&D Roadmap, pp. 10-11 (Dec. 2010) (emphasis added).

technology will follow this pattern."[119] In general, the cost and performance of any technology should improve with broader commercial deployment, but as noted in the recent CRS report (*see supra*), the knowledge gained though research, demonstration, and initial operating experience sometimes results in *increased* costs during the development period, and the magnitude and rate of development is not a one-size-fits-all trend.[120]

The scope and complexity of development issues for CCS are dramatically different than for other emission controls such as flue gas desulfurization ("FGD") or selective catalytic reduction ("SCR") technologies. The development challenges of CCS at coal-based power plants are unique due to the greater complexity of process integration, magnitude of operational considerations, and the significant increases to cost of electricity production. CCS for coal-based generation is also very unique with respect to the magnitude of CO_2 byproduct that must be handled, transported, and stored in geologic formations. For example, coal-combustion ash and FGD-related solids by-products are solid materials that can be handled and stored in a landfill, while CO_2 is generally captured and compressed to a supercritical liquid which must be stored in deep geologic formations, and will be subject to a more extensive, diverse, and in many cases undeveloped set of regulatory and legal requirements. EPA has acknowledged in their guidance document for PSD permitting for greenhouse gases that the scope of design, construction, and operation considerations are much different and unique for CCS compared to other emission control systems by noting:

> "EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long term storage."[121]

Shoehorning the development of CCS technologies into historic developmental and cost reduction curves for existing emission control systems is inappropriate and results in unrealistic

---

[119] 77Fed. Reg. at 22,416.

[120] Carbon Capture and Sequestration: Research, Development, and Demonstration at DOE, CRS Report 7-5700, at pp. 6, 9 (April 23, 2012).

[121] U.S. EPA. "PSD and Title V Permitting Guidance for Greenhouse Gases." March 2011. p. 36. www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

expectations of the performance, timing, and cost of CCS commercialization. EPA references one study by Rubin, et. al that applies this very methodology to predict that based on "typical development curves," CO_2 capture costs will be reduced by as much as 26% for coal-based generation "*after* installation of the first 100 GW of capacity."[122] Again, the preamble to the proposed rule does not include important context that is necessary to understand the results. The study itself notes that "there is currently little empirical data to support the assumptions and models used to calculate future CO_2 capture costs for power plants," and that "there are no easy or reliable methods...to quantify the magnitude of potential cost *increases* commonly observed during early commercialization." In regards to the methodology applied in the analysis, the study notes that "[o]ne drawback of this approach is that is does not explicitly include potential cost *increases* that may arise when building or combining components that have not yet been proven for the application and/or scale assumed." The study correctly notes that "an important caveat...is to recall that the cost and learning curve estimates in this study do not include the costs of CO_2 transport and storage." Also, the authors point out that "a study of this nature...has other important limitations that must be recognized. For one, the concept of a constant learning rate... often...is an over-simplification of actual cost trends for large-scale technologies."[123] Rather than assuming that any *decrease* in the costs associated with CCS at coal-fired generating units will occur during EPA's study period, EPA should be assuming that costs may increase, and could increase dramatically as new information is discovered.

Results of this study fail to provide a definitive assessment of first-of-a-kind ("FOAK") or N^{th}-of-a-kind ("NOAK") costs, performance, or risk, and represent, at best, conjecture. To begin, reliable FOAK estimates are difficult to generate in large part because commercial-scale CCS processes on a coal-based power plant have *not* yet been demonstrated. AEP completed a front-end engineering and design estimate for a commercial-scale CCS project at our Mountaineer Plant, which was designed to capture CO_2 from approximately 20% (235 MWe) of the combustion gas, was greater than $1 billion.[124] That project was cancelled, but it highlights the fact that first-mover CCS projects will be very expensive and that more reliable cost information for FOAK can only be derived from *operating* commercial-scale CCS demonstration

---

[122] Id. (emphasis added).
[123] Rubin, E.S., et. al. "Use of experience curves to estimate the future cost of power plants with CO2 capture." International Journal of Greenhouse Gas Control I, pp. 189-196 (2007) (emphasis added).
[124] Final Technical Report, Mountaineer Commercial Scale CCS Project, DE-FE0002673, pp. 7-8 (Dec 8, 2011).

projects at coal-based power plants. Reliable baseline cost, performance information, and lessons learned from FOAK CCS deployments and operation are required before the true scope of development challenges can be identified to support realistic projections for achieving a commercially acceptable NOAK CCS process. In short, accurate FOAK project cost and performance estimates require completion of commercial-scale demonstrations. Beyond that, NOAK project cost and performance estimates require a sound understanding of all aspects of the FOAK project, followed by further research, development, and refinement. Where we stand on that timeline today makes estimates for NOAK systems nothing more than fanciful speculation.

Further, assuming that the results of the Rubin, et al study cited by EPA accurately predict the development of commercial CCS, EPA should consider what the results actually say with respect to the magnitude and timescale of development. First, as noted previously, the study estimates CO_2 capture costs will be reduced by as much as 26% for coal-generation "*after* [emphasis added] installation of the first 100 GW of capacity." For context, the authors note that "the nominal value for this study is 100 GW – equivalent to roughly the first 25 years of experience for NO_x and SO_2 capture systems at coal-fired power plants."[125] Assuming 600 MW per unit, then 100 GW is equivalent to approximately 170 new coal generating units. Therefore, the study is suggesting that if the commercial development of CCS parallels the development of NO_x and SO_2 emission controls, then after 25 years and/or approximately 170 CCS projects, the cost of CCS for coal-based generation "can be expected" to be reduced by as much as 26%. As previously mentioned, the proposed rule estimates that "available CCS technologies would add around 80 percent to the cost of electricity for a new pulverized coal plant … ." Even with a 26% reduction in capture cost, the impact to the cost of electricity from CCS would preclude it from being commercially acceptable. Therefore, it cannot be concluded from the study referenced by EPA that the cost of CO_2 capture for coal-based generation will be sufficiently reduced to enable commercial acceptance of CCS in time to meet the requirements of the proposed NSPS. To the contrary, the study confirms that significant cost and development challenges remain before CCS becomes a commercially viable emission control option.

[125] Rubin, E.S. et. al. p. 192.

iii. Third EPA basis: "Limited amount of construction of new coal-fired power plants"[126]

EPA estimates that only a few new coal-based power plants will be built by 2020 and that as a result, these projects will have greater access to various financial incentives and funding mechanisms. In no way does this suggest that CCS is feasible as a practical matter or commercially available. Financial incentives are customarily required to support the development of technologies that are not ready for commercial deployment. As discussed previously, significant barriers to commercial acceptance remain that can only begin to be addressed through the deployment of numerous commercial-scale demonstration projects. It is unrealistic to assume that the limited number of new coal plants projected by EPA would shoulder the burden for the industry of overcoming CCS development barriers, while trying to operate as required to justify the investment. In other words, a new coal plant is designed to safely and reliably produce a commercial product – electricity; it would not be designed for the primary purpose of CCS research and development.

iv. Fourth EPA basis: "State Requirements for CCS"[127]

EPA cites state regulatory programs in Montana and Illinois as indicators of CCS feasibility. These are regulatory programs that limit greenhouse emissions, not affirmations that CCS is feasible as a practical matter or commercially acceptable. In fact, no commercial-scale CCS projects on a coal-based generating unit are operating in either state, and none has been identified that is currently under construction.

EPA also references operating or planned CO_2 capture processes. The systems in operation provide CO_2 to the food processing industry and to a soda ash plant. Another is a synthetic natural gas plant that provides CO_2 for enhanced oil recovery. The AEP Mountaineer CCS project is referenced, but as noted previously, this was not a commercial-scale project. Only one of the four remaining planned projects identified was at commercial scale.

These examples point to the potential of CCS for coal-based power plant operations and to the ongoing efforts to development of the technology. However, the information presented by

[126] 77 Fed. Reg, at 22,416.
[127] Id.

EPA does not indicate that commercially available CCS technology is a viable emission control option for meeting the proposed NSPS requirements.

VI. Response to Technical Questions For Which EPA Requested Comments

In the proposed rule, EPA requested comment on several technical issues. Responses to those requests are provided below:

A. Use of gross-based output limits[128]

EPA requested comment on the use of gross-based output standards. Earlier this year in the NSPS for Subpart Da conventional emissions EPA did not require a net output approach "[d]ue to the lack of net-output-based emission rates for multiple type of EGUs with various control configurations over a range of operating conditions."[129] EPA should be consistent in the use of gross-based output standards in this rulemaking. However, the use of gross-based generation results in a number of complex technical and operational considerations that can influence emission rates and unit efficiencies. These issues warrant a much greater technical analysis, which further supports that finalization of these standards is premature and that the proposed rule should be changed to an advanced notice of proposed rulemaking so that the agency can fully evaluate the implications and design of gross-based output standards.

B. Adequacy of the proposed 1,000 lb/MWh NSPS[130]

EPA requested comment on whether the proposed standard of 1,000 lb/MWh should more appropriately be set within the range of 950 and 1,100 lb/MWh.[131] Based on the lack of commercially available CO_2 control technologies for fossil-fired generation and expected higher capacity factors of new natural gas combined cycle ("NGCC") units compared to historic operations, it is recommended that a more appropriate standard for new NGCC units is 1,100 lb/MWh or more. A separate standard specific to new coal units should be established that reflects the best demonstrated performance of existing advanced coal technologies.

---

[128] Id. at 22,416.
[129] 73 Fed. Reg. 33642 at 4.
[130] 77 Fed, Reg, at 22,414.
[131] Id.

C. CCS as the best system of emission reductions

The proposed rule states that "[a]lthough we [EPA] are not proposing that CCS, including the 30-year averaging compliance option, does or does not qualify as the BSER adequately demonstrate, we also solicit comment on that issue."[132] As shown by the technical comments of CCS above, CCS clearly does not qualify as the Best System of Emission Reductions within the meaning of section 111(a) of the Clean Air Act.

D. Coal refuse[133]

EPA solicits comments on developing a subcategory for electric generating units that burn over 75% coal refuse on an annual basis. AEP supports EPA's proposed subcategory that would exempt such units from the proposed NSPS requirements. Further, AEP supports additional fuel-specific subcategorization that establishes a coal-specific standard that reflects the best demonstrated performance of existing advanced coal technologies.

E. Combined heat and power[134]

The proposed rule states that EPA is "also considering and requesting comment on if exempting all CHP facilities where useful thermal output accounts for at least 20 percent of the total useful output from this proposed rule." AEP supports an EPA's proposed exemption for such facilities.

F. Stationary simple cycle turbines[135]

EPA requests comments on the exemption of stationary simple cycle turbines from the proposed rule. AEP supports EPA's proposed exemption for such facilities. Additionally, in the case where simple cycle turbines are constructed with the intent to operate prior to the future construction of a heat recovery steam generator (HRSG), such turbines should be exempted from the proposed rule until such time that construction of the HRSG and related equipment is completed and the unit commences operation in a combined cycle mode.

---

[132] Id. at 22,420.
[133] Id. at 22,431.
[134] Id.
[135] Id. at 22,431-22,432.

VII. Conclusion

For all of the foregoing reasons, EPA's proposed NSPS for the new category of fossil fuel-fired electric generating units created specifically in Subpart TTTT is fatally flawed and should be withdrawn. If EPA chooses to proceed with the current rulemaking, such substantial additional information and analysis is required that a new proposed rule must be issued. Therefore, an alternative might be to issue a notice that the current proposal will be deemed an advance notice of proposed rulemaking, have no immediate effect, and to solicit information necessary to determine the "best system of emission reduction" that is adequately demonstrated for the existing source categories in Part 60. In particular, the following issues must be addressed before establishing a legitimate standard of performance for GHG emissions from EGUs.

A. Fuel-specific standards should be established in lieu of a one-size-fits-all approach that effectively requires one fuel (coal), but not another (natural gas) to use an undeveloped control technology

If EPA chooses to move forward with this rulemaking, then EPA's recognition of the fundamental differences between natural gas and coal infrastructure and markets, and between gas-fired generation technologies and coal-fired generation technologies, requires the two source categories to remain separate for purposes of category-appropriate Section 111 performance standards for GHGs. Alternatively, EPA could create separate source subcategories with subcategory-appropriate GHG performance standards. Regardless, EPA's proposed performance standard is supported only for, and should be limited to only, the source category or subcategory of NGCC EGUs. EPA recognizes that no existing technology has been deployed that would allow coal-based EGU's to meet the same standard. Integrated gasification combined cycle (IGCC) units should be maintained in a separate category or subcategory. There are currently only two operating IGCC units in the United States, and separate greenhouse gas performance standards are needed for this unique emerging technology.

Moreover, based on the factual errors identified above, EPA needs to undertake additional analyses to accurately describe both the costs and benefits of this rule. Should the direct benefits of the rule not greatly exceed the costs, EPA should pull the rule entirely, and

propose a standard that can be achieved using commercially available technologies at a reasonable cost. EPA must:

1. Quantify the costs of the rule using at least a 30-year time horizon.
2. Analyze the regional differences in fuel supply that may alter new generation economics and lead to additional costs associated with this national standard.
3. Include other modeling scenarios which explore other factors that may influence natural gas prices that reflect the range of pricing and price spreads between coal and gas experienced in the past decade, and that may plausibly occur in the long term future.
4. Rerun IPM with revised capital costs for new NGCC and PC units.
5. Recalculate the levelized cost of electricity using more plausible capacity factors for new natural gas combined cycle units.
6. Remove from the RIA speculative dialogue on the Societal Cost of Carbon and health benefits, as the numbers presented are overly speculative and arbitrary.

EPA has applied a double-standard, rationalizing the need for greenhouse gas emission reductions and the availability of CCS as it relates to coal-based generation, and ignoring its potential applicability to natural gas combined cycle generating units. EPA claims in the proposed rule that "[H]uman-induced climate change has the potential to be far-reaching and multidimensional," and that climate change "threatens public health," "is expected to have numerous effects on public welfare," "threaten[s] energy, transportation, and water resource infrastructure," and "will fundamentally rearrange U.S. ecosystems."[136] Further, the agency expresses an urgency to address these impacts by stating that "the environmental, economic, and humanitarian risks of climate change indicate a pressing need for substantial action" and that "[e]ach additional ton of greenhouse gases emitted commits us to further change and greater risks."[137]

To address these issues, EPA proposes a standard of 1,000 lb/MWh "based on the performance of widely used natural gas combined cycle (NGCC) technology."[138] The proposed limit is intended to have minimal, if any, impacts on the design, cost, operations, or prospects for new NGCC units, but will significantly impact, if not effectively eliminate the development of

[136] 77 Fed. Reg. 22402
[137] Id. 22395 (citation omitted).
[138] Id. 22392

new coal units unless CO_2 control technologies become commercially available. EPA downplays this concern by noting that "[c]apture of CO_2 from industrial gas streams has occurred since the 1930s..." The agency concludes that "the costs of CO_2 capture and compression represent the largest stumbling block to widespread commercialization of CCS," but that "significant reductions in the cost of CO_2 capture" are expected. To support this claim, EPA cites a study that estimates capture costs will decline by 40% for NGCC units and by up to 26% for coal-based generating units.[139] Based on these references and other information, EPA concludes that CCS is an available control option for coal-based generation. Yet, despite referencing that CO_2 capture has been used in the natural gas industry, and presenting estimates that capture costs will drop more significantly for NGCC than for coal, EPA does not require NGCC developers to use this undeveloped emission control technology. In fact, EPA is silent as to why CCS is or is not equally applicable to NGCC.

By 2020, EPA estimates that nearly 25 GW of new NGCC capacity will be developed, and that no new coal units beyond those already on the books will be constructed.[140] Based on conservative estimates, potential CO_2 emissions from this new natural gas capacity alone would be over 90 million tonnes per year.[141] EPA notes that "under a wide range of future market conditions, this proposed EGU GHG NSPS is not expected to change GHG emissions for newly constructed EGUs."[142]

But if the magnitude of climate change impacts are as severe as EPA has stated; if the significance of these risks requires immediate reductions of GHG emissions; and if EPA's logic for determining that CCS is available for coal-based generation is equally applicable to NGCC, then why doesn't EPA require NGCC units to use CCS to reduce the potential 90 million tonnes of new CO_2 emissions from these sources as well? The answer is two-fold. One, as noted in prior sections, CCS is *not* commercially available for coal-based generation or NGCC units. Moreover, the development of CCS for *any* EGU faces significant technical, financial, and legal barriers. And two, the proposed rule, according to EPA "does encourage the current trend towards cleaner generation" and "will send a strong signal both domestically and internationally..... to consider less GHG-intensive forms of power generation." In other words,

---

[139] Id. 22415-22416

[140] Proposed EGU GHG NSPS. Regulatory Impact Analysis. Mar 2012. p. 5-14.

[141] Calculation: (24.8 GW new NGCC) * (950 lb CO_2/MWh) * (1 tonne / 2204.6 lb) *(1000 MW/GW) *(8760 hr/yr) = 93,615,894 tonnes/yr

[142] Proposed EGU GHG NSPS. Regulatory Impact Analysis. Mar 2012. p. 5-1.

the proposed rule supports a policy that effectively eliminates new coal-based power generation - that is not the purpose of the NSPS regulatory program.

The purpose of the NSPS regulatory program is to establish a standard of performance that "reflects the degree of emission limitation achievable through the application of the best system of emission reduction."[143] NSPS is not an appropriate vehicle for establishing a domestic energy policy that effectively restricts fuel choices and technologies by requiring only certain sources to employ control technologies that are not commercially available and are not expected to be available for many years. EPA should establish fuel-specific NSPS that represent a standard of performance that has been demonstrated to be achievable with commercially available control technologies.

B. EPA should not base a standard on technology that is not commercially available, but if EPA insists on promulgating a standard based on projected future technology developments, the long-term average limit should be revised to align with a more realistic CCS development timeline

As discussed in the prior sections, commercial CCS technology is not currently available for coal-based generation, and is not expected to be commercially available within the next decade. In proposing the 30-year average option, EPA is essentially acknowledging that the significant development of CCS technology remains and that at least ten years (the point in time when a more stringent limit becomes applicable) is needed for that development. Instead of requiring a new coal-based unit to achieve an emission limit that, in essence, mandates the immediate use of a technology that is not commercially available (option one: annual limit), or an emission rate that is premised on the hope of technology development (option two: 30-year limit), EPA should establish a coal-specific limit based on the performance of operating advanced coal generation processes. As noted above, EPA may not establish standards "solely on the basis of ...'crystal ball inquiry.'"[144] Accordingly, the proposed standard should be revised, the existing separate source categories should be retained, and different standards should apply to NGCC units and the various fuel-based subcategories of steam EGUs.

---

[143] Clean Air Act. Section 111(a)(1)
[144] Essex Chem. Corp. v. Ruckelshaus, 486 F.2d at 433.

However, if EPA decides to retain the option for a longer-term average, the duration of the average should be increased to a 40- or 50-year average. This would recognize that CCS for coal-based generation is currently not commercially available and, at the current pace of development, will not be viable in the next decade. The time period also approximates the 2050 date by which President Obama set a goal of reducing greenhouse gas emissions in the United States by 83 percent. EPA could revisit the efficacy of the long-term average in context with the state of CCS development during the required 8-year NSPS review cycle.

The long-term limit also should be designed so that applicable limits during the non-CCS phase of operations (which in the proposed rule would be ten years) accurately reflect the best demonstrated emission rate achieved by operating advanced coal technologies. The current assumed rate of 1,800 lb/MWh should be revisited. AEP is currently constructing an ultra-supercritical unit, which is employing state-of-the-art advanced coal technology. Even this unit would not be able to reliably achieve an 1,800 lb/MWh rate, and it will be the only unit in the United States with such an advanced steam cycle. Based on the subbituminous fuel used and the projections for load fluctuation and periodic unit startups, AEP estimates an annual gross CO_2 emission rate closer to 1,900 lb/MWh.

Further, the proposed 10-year threshold for becoming subject to a lower emission limit is too stringent and does not parallel the expected timeframe for when CCS will be commercially acceptable. In context with the above comments regarding the need for a longer overall averaging period (40-50 year average), it is recommended that a lower emission limit not become effective until year 21 of the long-term average.

C. EPA should either withdraw its proposed rule or convert it to an advance notice of proposed rulemaking, and continue gathering information

EPA's proposed Subpart TTTT has many of the characteristics of an advance notice of proposed rulemaking. EPA has acknowledged that it lacks sufficient information to propose greenhouse gas NSPS for modified and reconstructed electric utility generating units or for electric utility generating units located outside the continental United States. Yet, EPA's lack of adequate information to set EGU GHG performance standards for modifications, reconstructions, and units located outside the continental United States is no greater than its lack of information to set GHG performance standards for new coal-fired electric generating units. EPA's

information on CCS, moreover, is incomplete, flawed, and insufficient for the standard proposed. And, there is an important legal difference between a proposed performance standard and an advanced notice of proposed rulemaking – the applicability trigger date is the date of proposed rulemaking under Clean Air Act § 111(a).[145] Thus, failure to withdraw these proposed rules would set a de facto GHG standard that is not realistically achievable for coal-fired EGUs.

Based on the legal concerns described above, EPA must withdraw its proposed Subpart TTTT or convert it to an advance notice of proposed rulemaking. EPA may then properly determine **separate** greenhouse gas new source performance standards for stationary sources that are subject to Subpart Da and for natural gas combined cycle systems in Subpart KKKK. Such a revision of Subparts Da and KKKK would be unnecessary, pursuant to the "efficacy" principle of Section 111(b)(1)(B) of the Clean Air Act. According to statute, the Administrator need not review and revise any new source performance standard "if the Administrator determines that such review is not appropriate in light of readily available information on the efficacy of such standard."[146] Here, revising Subpart Da would not be efficacious because EPA projects that no new coal-fired electric generating units will be subject to the proposed standard before 2020 anyway.[147] Moreover, the obligation to install Best Available Control Technology for greenhouse gases under the Tailoring Rule obviates the need for, and benefits of, a GHG performance standard for new coal-fired electric generating units. Thus, revising Subpart Da now would be no more efficacious than waiting to obtain more information before regulating CO_2 emissions from new coal-fired electric utility generating units.

[145] See 42 U.S.C. § 7411(a)(2) (defining "new source" to include any stationary source constructed "after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance . . . which will be applicable to such source.").
[146] 42 U.S.C. § 7411(b)(1)(B).
[147] See 77 Fed. Reg. at 22,398-99.

Appendix A - Assessments of the State of CCS Development for Coal-Based Electric Generation

Organization	Date	State of CCS	Barriers to Commercially Acceptable CCS	Prospects for CCS Development
President Obama's Interagency Task Force on Carbon Capture and Storage. Report of the Interagency Task Force[148]	Aug. 2010	"Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation because they have not been demonstrated at the scale necessary to establish confidence for power plant application." (p.50) "CCS technologies...are not likely to be widely deployed at coal-fired power plants....without additional knowledge generated by research, development, and demonstration activities." (p.87)	"Though CCS technologies exist, "scaling up" these existing processes and integrating them with coal-based power generation poses technical, economic, and regulatory challenges." (p.9) "..barriers hamper near-term and long-term demonstration and deployment of CCS technology." (p.14) "A concerted effort to properly address financial, economic, technological, legal, institutional, and social barriers will enable CCS to be a viable climate change mitigation option..." (p.8)	"Administration analyses of proposed climate change legislation suggest that CCS technologies will not be widely deployed in the next two decades..." (p.8) "The focus of CCS RD&D is....to facilitate widespread cost-effective deployment after 2020." (p.9)
The National Coal Council (a Federal Advisory Committee to Secretary of Energy Chu). *Expedited CCS Development: Challenges & Opportunities*[149]	Mar. 2011	"..a range of issues must be addressed before CCS processes are commercially acceptable for coal-based electric generating units. ...key development concerns include the fact that commercial-scale CCS processes have *not yet* been demonstrated on a coal-fired generating unit" (p.1)	"...the current CCS demonstration program in the [U.S.]...is not on pace to significantly advance CCS development in the near-term due to technical and equally non-technical obstacles.... Challenges to CCS development...can be broadly categorized into technical, financial, and regulatory areas." (p.1)	"At the current [development] rate, CCS technologies will continue to be in an early development stage by 2020." (p.64) "Ongoing and planned CCS projects for coal-based generation are advancing the development of the technology, but not at the pace necessary to support an expedited and broad-based deployment of CCS by 2050." (p.14)
DOE / NETL Advanced Carbon Dioxide Capture R&D Program: Technology Update[150]	May 2011	"...in their current state of development [the CO_2 capture technologies being used in industrial applications] are not ready for implementation on coal-based power plants" (p.4)	"[CO_2 capture] technologies are not ready for implementation on coal-based power plants [because] (1) they have not been demonstrated at the larger scale necessary for power plant application; (2) the parasitic loads (steam and power) required to support CO_2 capture would decrease power generating capacity...; and (3) if successfully scaled-up, they would not be cost effective at their current level of process development." (p.4)	"It is anticipated that successful progression from laboratory- to full-scale demonstration will result in several of these [CO_2 capture] technologies being available for commercial deployment by 2030." (p.10)
DOE / NETL CO_2 Capture and Storage RD&D Roadmap[151]	Dec. 2010	"...cost-effective and efficient CCS technologies will need to be developed and demonstrated at full-scale prior to their availability for widespread commercial deployment." p. 5 "...at their current state of development these [CO_2 capture] technologies are not ready for implementation on coal-based power plants." (p.21)	"...advanced technologies developed in the CCS RD&D effort need to be tested at full scale in an integrated facility before they are ready for commercial deployment." (p.11)	"....the overall timeline for RD&D....involves pursuing advanced CCS technology from the fundamental / applied stage through pilot-scale so that full-scale demonstrations can begin by 2020. The RD&D effort will produce the data and knowledge needed to establish the technology base, reduce implementation risks by industry, and enable broader commercial deployment of CCS to begin by 2030." (p.10)
DOE / NETL Carbon Sequestration Program: Technology Program Plan[152]	Feb. 2011	"The overall objective of the Carbon Sequestration Program is to develop and advance CCS technologies that will be ready for widespread commercial deployment by 2020." (p. 10)	"To accomplish widespread [commercial] deployment [of CCS by 2020], four program goals have been established: (1) [reduce CCS related costs]; (2) [improve the] ability to predict CO_2 [geologic] storage capacity; (3) develop technologies to demonstrate that...CO_2 remains in the injection zones; (4) complete Best Practices Manuals...for site selection, characterization, site operations, and closure practices." (p. 10)	"Only by accomplishing these goals [of the DOE Carbon Sequestration Program] will CCS technologies be ready for safe, effective commercial deployment both domestically and abroad beginning in 2020 and through the next several decades." (p.10)

[148] "Report of the Interagency Task Force on Carbon Capture and Storage." Aug 2010. www.fe.doe.gov/programs/sequestration/ccs_task_force.html
[149] "Expediting CCS Development: Challenges and Opportunities." Mar 2011. Library of Congress Catalog #2011926623. www.nationalcoalcouncil.org
[150] Department of Energy / National Energy Technology Lab. May 2011. www.netl.doe.gov/technologies/coalpower/ewr/pubs/CO2Handbook/
[151] Department of Energy / National Energy Technology Lab. Dec 2010. www.netl.doe.gov/technologies/carbon_seq/refshelf/CCSRoadmap.pdf
[152] Department of Energy / National Energy Technology Lab. Feb 2011. www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf

Appendix E

Supplemental AEP Comments on the 2012 Proposed NSPS for New Sources

AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

August 8, 2013

Original by Mail
E-mail copy submitted to: a-and-r-docket@epa.gov

EPA Docket Center
U.S. Environmental Protection Agency
Mail Code #2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460

ATTN: Docket ID No. EPA-HQ-OAR-2011-0660

Re: Supplemental Comments on Proposed Rule to Set Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units

American Electric Power (AEP) is submitting the following supplemental comments to the Environmental Protection Agency (EPA or Agency) as it develops a revised proposal to set a new source performance standard (NSPS) for carbon dioxide (CO_2) emissions from fossil-fueled electric generating units (EGUs) under section 111 of the Clean Air Act (CAA or the Act).[1] The agency's initial proposal, published in April 2012,[2] would have adopted a single standard for a combined source category including solid, liquid, and gaseous fossil fuel fired electric generating units, but the stringency of the standard would have effectively banned the construction of any new units other than highly efficient combined cycle natural gas fired units.

On June 25, the President announced his "Climate Action Plan," a series of executive actions designed to reduce carbon emissions in the U.S., prepare for the impacts of climate change, and emerge as a leader in international discussions. The accompanying Presidential Memorandum directed EPA to issue a revised proposal no later than September 20, 2013, for new sources, and to undertake the development of a proposal for modified, reconstructed, and existing sources that would be issued by June 1, 2014, and finalized by June 1, 2015. As part of the development process, the agency was instructed to directly engage with States, tribal leaders, leaders in the power sector, labor leaders, non-governmental organizations, and other experts on issues that would inform the design of the program, specifically focusing on ways to reduce costs, ensure that the standards enable continued reliance on a range of energy sources and technologies, and allow for the continued provision of reliable and affordable electric power. The memorandum expressly

[1] *Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generation Units*, 77 Fed. Reg. 22,392 (April 13, 2012).
[2] *Id.*

states that it is not intended to impair or otherwise affect the authority granted by law to any department, agency, or the head thereof.

The primary purpose of these supplemental comments is to clarify and further explain the limits on EPA's authority to adopt a CO_2 performance standard for new fossil fuel-fired EGUs under section 111(b) of the Clean Air Act, and why a standard that effectively bans the use of coal, the most dominant energy resource in America, for the generation of electricity exceeds the limits of EPA's authority.

It is critical for EPA to distinguish between the narrow authority granted to the agency under the Clean Air Act, and the traditional states sovereign powers related to such matters as the regulation of electricity that are reserved to the states under the Tenth Amendment to the U.S. Constitution. The structure of the Clean Air Act deliberately confines EPA's authority to the areas in which its expertise is greatest: the evaluation of technologies to reduce or eliminate emissions; the applicability of those technologies to various classes and categories of sources; the cost of employing such technologies; and the energy and non-air environmental impacts associated with the use of those technologies. By contrast, well-established Supreme Court precedent clearly bars EPA from overriding or infringing upon a traditional state sovereign function unless Congress has adopted "unmistakably clear" statutory language that expressly authorizes the agency to do so. As discussed below, neither section 111 nor any other provision of the Clean Air Act contains any explicit authority for EPA to usurp the role of the states in evaluating the mix of options used to generate electricity, authorizing the addition of specific new generation resources, or siting new generation resources within the state. This lack of express authority confirms Congress' intent to respect and preserve the states' historic role in the regulation of electricity, and confirms that EPA lacks the authority to adopt a CO_2 standard that effectively bans the use of coal for new electricity generation units.

This clear limitation of EPA's authority is equally applicable to the second rulemaking EPA has been directed to initiate for modified, reconstructed, and existing sources under sections 111(b) and (d) of the Clean Air Act. For the same reasons discussed herein, this limitation requires the agency to respect and preserve state sovereign powers over matters relating to electricity generation, such as determining the appropriate mix of generating resources within a state.

AEP is a holding company and, through its public utility operating companies and other subsidiaries, ranks among the nation's largest generators of electricity. AEP companies own over 37,000 megawatts of generating capacity in the U.S. and deliver electricity to more than 5.3 million customers in 11 states. AEP also owns the nation's largest electricity transmission system, a roughly 39,000-mile network that includes more 765-kilovolt extra-high-voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP's

utility units operate as AEP Ohio, AEP Texas, Appalachian Power Company (in Virginia, West Virginia and Tennessee), Indiana Michigan Power Company, Kentucky Power Company, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas).

I. OVERVIEW OF AEP'S SUPPLEMENTAL COMMENTS

A. Legal Flaws of EPA's Proposed CO_2 NSPS

On April 13, 2012, EPA proposed to establish a NSPS limit of 1,000 pounds of CO_2 per megawatt-hour (MWh) of electricity generated on a gross basis and averaged over a 12-month annual period.[3] This CO_2 emissions limit applies (with certain limited exceptions)[4] to each new fossil-fueled EGU that commences construction after April 13, 2012, and that has "a base load rating of more than 73 megawatts ... heat input of fossil fuel."[5] According to EPA, the proposed 1,000 pounds/MWh CO_2 limit is "based on the performance of widely used natural gas combined cycle (NGCC) technology" without requiring any further CO_2 emissions controls on such gas-fueled units.[6] By contrast, a new coal-fueled EGU can comply with the proposed CO_2 limit only through the use of carbon capture and storage (CCS) technology – a technology that EPA has determined is not adequately demonstrated or available on a commercial scale today.[7] The EPA proposal attempts to bridge this technology gap for coal-fueled power plants by establishing an alternative 30-year averaging compliance option for new coal-fueled EGUs that is intended to provide additional time for the demonstration and deployment of the CCS technology on any new unit subject to the proposed CO_2 NSPS limit.[8]

AEP submitted detailed comments on EPA's proposed NSPS rule on June 25, 2012. These comments identified the many legal, policy, and technical flaws in the EPA proposal and explained why these flaws leave EPA with no choice but to withdraw the CO_2 NSPS proposal in its entirety. Notable flaws identified in AEP's June 25th comments include the following:

---

[3] *See* proposed 40 C.F.R. § 60.5520(a), as set forth in 77 Fed. Reg. at 22,436.
[4] The EPA proposal would exempt from the proposed CO_2 NSPS three minor categories of steam electric generating units, including those units under development that meet the criteria established for "transitional sources." *See* 40 C.F.R. § 60.5510(b), as set forth in 770 Fed. Reg. at 22,436.
[5] *See* proposed 40 C.F.R. § 60.5509, as set forth in 77 Fed. Reg. at 22,436.
[6] 77 Fed. Reg. at 22,392.
[7] In the preamble to the proposed NSPS rule, EPA specifically declined to select CCS as the "'best system of emissions reduction' that 'has been adequately demonstrated' for new coal-fired power plants." 77 Fed. Reg. at 22,411. In addition, the Agency determined in a 2010 Interagency Task Force report that CCS technologies "are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application." Report of the Interagency Task Force on Carbon Capture and Storage, August, 2010.
[8] *See* proposed 40 C.F.R. § 60.5520(b), as set forth in 77 Fed. Reg. at 22,436.

- The NSPS proposal violates the CAA because it sets a CO_2 performance standard based on a technology that is not "adequately demonstrated" and not "achievable" for all power plants within the electric power source category. The CAA requires EPA to adopt a CO_2 performance standard that is "adequately demonstrated" and "achievable" for all sources within a particular source category.[9] In the NSPS proposal, EPA is proposing a single uniform CO_2 performance standard that is achievable only by natural gas combined cycle units. The standard is infeasible for coal-fueled power plants because CCS technologies, the only option for coal-fueled plants to meet the standard, are not adequately demonstrated or available on a commercial scale today.

- Providing a 30-year averaging period as an alternative compliance option for new coal-fueled power plants does not cure this legal flaw. EPA's standards must be based on technologies that are demonstrated today, not technologies that may be available in the future. Moreover, such an alternative is not a realistic solution to bridging the technology gap for meeting the proposed CO_2 performance standard. Neither developers nor lending institutions will be willing to make a multi-billion dollar investment in a new coal-fueled plant unless and until they can secure adequate assurances that a CCS technology capable of achieving the CO_2 performance standard can be installed and operated reliably within the initial ten-year period.

- The NSPS proposal is unlawful because it mandates the use of a particular technology. The CAA clearly states that EPA is not authorized "to require ... any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance."[10] Yet, this is what EPA has done by proposing a 1,000 lb/MWh standard for all fossil-fueled power plants. No adequately demonstrated technology makes it possible for coal-fueled power plants to comply because the only feasible means of complying with the proposed performance standard is through the use of natural gas combined cycle technology. EPA's proposal is a mandate for the construction of new gas-fired generation, and a ban on construction of new coal-fueled plants.

B. Additional legal reasons why EPA lacks authority to finalize the proposed CO_2 NSPS

The purpose of these supplemental comments is to highlight an additional fundamental principle of statutory construction that both informs and limits the exercise of EPA's authority under section 111 of the CAA. This principle of statutory construction derives from the historic role of the states in regulating the generation of electricity, and from the constitutional underpinnings of American federalism. This principle further underscores

[9] Section 111(a)(1) of the Clean Air Act (defining "standard of performance").
[10] Section 111(b)(5) of the Clean Air Act.

EPA's lack of authority to adopt a CO_2 performance standard that could interfere with or infringe on state regulation of electricity generation by effectively banning the construction of any new coal-fueled EGUs. For these reasons, AEP continues to believe the proposed rule to set a CO_2 NSPS for power plants is legally deficient and, as a result, the Agency has little choice but to withdraw its NSPS proposal in its entirety.[11]

As discussed below in greater detail, it is a well-established rule of statutory construction that EPA cannot rely on a broad delegation of authority to regulate air emissions to override a traditional and fundamental state sovereign function reserved to the states under the tenth amendment of the Constitution. This rule of construction clearly bars EPA from using a general delegation of authority under CAA section 111(b) to adopt a CO_2 performance standard that effectively bans the construction of new coal-fired EGUs. EPA lacks the authority to adopt such a fuel-discriminatory performance standard unless Congress makes its intention "so 'unmistakably clear' in the language of the statute" that EPA can override states' long-standing traditional powers to regulate matters pertaining to the generation of electricity.[12]

A review of the relevant provisions of Act reveals that Congress has not adopted such unmistakably clear statutory language to ban coal use, or otherwise regulate the generation of electricity under section 111(b) or any other provision of the CAA. Furthermore, Congress' failure to do so provides further confirmation that EPA lacks the authority to adopt a CO_2 performance that would effectively override a traditional and fundamental sovereign function of the states.

II. FEDERAL AGENCIES MAY NOT OVERRIDE OR INFRINGE ON TRADITIONAL STATE SOVEREIGN POWERS UNLESS EXPRESSLY AUTHORIZED TO DO SO.

Well-established court precedent clearly bars a federal agency from overriding or infringing upon a traditional state sovereign power unless Congress has adopted "unmistakably clear" statutory language that expressly authorizes the agency to do so.

One leading Supreme Court decision that concisely enunciates this fundamental principle of statutory construction is *Will v. Michigan Department of State Police*.[13] In *Will*, the Supreme Court describes this principle as an "ordinary rule of statutory construction that

---

[11] The Utility Air Regulatory Group (UARG), a not-for-profit association of individual electric generating companies and national trade associations of which AEP is a member, submitted supplemental comments to the docket for this rulemaking on May 16, 2013, responding to two notice of intent to sue letters that had been sent to the Agency with regard to this rulemaking. As UARG noted in that letter, because the one-year deadline for taking final action on the proposed rule has passed, the proposed rule has terminated and formal withdrawal of the rule is not necessary. Nevertheless, formal withdrawal of the April 2012 proposed rule by EPA would benefit the public, particularly in light of the direction EPA has been given to issue a new proposal, so as to avoid confusion regarding the April proposal's legal effect.

[12] *Will v. Michigan Department of State Police*, 491 U.S. 58 (1989).

[13] 491 U.S. 58 (1989). *See* also *Altria Group, Inc. v. Good*, 555 U.S. 70, 77 (2008) (providing a concise summation of the fundamental principle of statutory construction that was articulated in *Will*).

if Congress intends to alter the 'usual constitutional balance between the States and the Federal Government,' it must make its intention to do so 'unmistakably clear in the language of the statute.'"[14] The Court goes on to state that "Congress should make its intention 'clear and manifest' if it intends to pre-empt the historic powers of the States"[15] and that "'the requirement of clear statement assures that the legislature has in fact faced, and intended to bring into issue, the critical matters involved in the judicial decision.'"[16]

The principle has been applied in cases across a broad spectrum of federal legislation. One notable case is *Rapanos v. United States*,[17] in which the Supreme Court affirmed the clear limitations placed on a federal environmental agency's authority to intrude or infringe upon traditional state sovereign powers. In *Rapanos*, the U.S. Army Corps of Engineers (Corps) broadly interpreted the phrase "waters of the United States" to include "ephemeral streams," "drainage ditches," and other structures or channels that are "typically dry" or "have little flow in a year."[18] In rejecting this expansive reading of an admittedly ambiguous statutory phrase, the Supreme Court ruled that the Corps' interpretation would "result in a significant infringement of the States' traditional and primary power over land and water use" and that such regulation "is a quintessential state and local power."[19] Furthermore, the Court stressed that the Corps' efforts to expand its jurisdictional authority over wetlands would allow "the Corps to function as a *de facto* regulator of immense stretches of intrastate land – an authority the agency has shown its willingness to exercise with the scope of discretion that would befit a local zoning board." Finally, in summing up its rationale for invalidating the Corps' regulation, the Court underscored: "We ordinarily expect a 'clear and manifest' statement from Congress to authorize an unprecedented intrusion into traditional state authority. The phrase 'the waters of the United States' hardly qualifies."[20]

Other cases abound in which the Supreme Court has insisted upon an "unmistakably clear" statement from Congress before it will affirm a federal agency's authority to override or infringe on a traditional state sovereign power. Among them is *Solid Waste Agency of Northern Cook County v. United States Army Corps of Engineers* (*SWANCC*),[21] a case in which the Supreme Court held that Army Corps of Engineers cannot exercise federal jurisdiction over isolated ponds and mudflats used by migratory birds because it would result in a significant impingement of states' traditional and primary power over land and

---

[14] *Will*, 491 U.S. at 65 (citing *Atascadero State Hospital v. Scanlon*, 473 U.S. 234, 242 (1985) and *Pennhurst State School and Hospital v. Halderman*, 465 U.S. 89, 99 (1984)).
[15] *Will*, 491 U.S. at 65 (citing *Rice v. Santa Fe Elevator Corp.*, 331 U.S. 218 (1947)).
[16] *Will*, 491 U.S. at 65 (citing *United States v. Bass*, 404 U.S. 336, 349 (1971)).
[17] 547 U.S. 715 (2006) (plurality opinion). Significantly, Justice Kennedy's concurring opinion in *Rapanos* accepted the "clear and manifest" principle as stated in the plurality's decision, but disagreed with the need for the application of the principle in *Rapanos* due to the statutory limitations placed on the Corps' authority by the phrase "navigable waters." 547 U.S. at 776.
[18] 547 U.S. at 725, 727.
[19] 547 U.S. at 738.
[20] 547 U.S. at 738 (citing *BFP v. Resolution Trust Corporation*, 511 U.S. 531, 544 (1994).
[21] 531 U.S. 159 (2001)

water use without a clear legislative authorization for such impingement.[22] In so ruling, the Court emphasized that the Corps was not entitled to any "*Chevron* deference" in those situations "where the administrative interpretation alters the federal-state framework by permitting federal encroachment upon a traditional state power" – such as, in the case of *SWANCC*, the federal environmental regulation of matters pertaining to "land and water use."[23]

III. THE REGULATION OF ELECTRICITY GENERATION IS A TRADITIONAL STATE SOVEREIGN POWER THAT COURTS HAVE RESPECTED AND PRESERVED.

Courts have recognized the regulation of electricity generation as a quintessential state sovereign function that federal agencies have a legal obligation to respect and preserve unless Congress has otherwise made its intentions clear and manifest. This perspective was clearly articulated by the Supreme Court in *Pacific Gas & Electric v. State Energy Resource Conservation & Development Commission*,[24] a case in which the Court ruled that state laws requiring new nuclear power plants to have adequate storage capacity for spent nuclear fuel are not preempted by the Atomic Energy Act of 1954. In so ruling, the Court stated:

> Need for new power facilities, their economic feasibility, and rates and services are areas that have been characteristically governed by the States. ... With the exception of the broad authority of the Federal Power Commission, now the Federal Energy Regulatory Commission, over the need for and pricing of electrical power transmitted in interstate commerce, ... these economic aspects of electrical generation have been regulated for

[22] *SWANCC*, 531 U.S. at 174

[23] In addition, there are many other instances in which courts have insisted upon an unmistakably clear statement from Congress before the court will affirm that a federal agency has authority to override or infringe on traditional state sovereign power. One such example is *Will v. Michigan,* in which the Court held that the term "person" in a civil rights law does not include the States acting in their sovereign capacity. 491 U.S. 58, 65 (1989). Another notable example is *Nixon v. Missouri Municipal League*, in which the Supreme Court invoked its "working assumption that federal legislation threatening to trench on the States' arrangements for conducting their own governments should be treated with great skepticism, and read in a way that preserves a State's chosen disposition of its own power, in the absence of [a] plain statement [of congressional intent]" and that "[t]he want of any 'unmistakably clear' statement to that effect ... is grounds for the Court's ruling to respect states' sovereign powers on these telecommunication matters." 541 U.S. 125, 140-41 (2004). A third example is *Gregory v Ashcroft*, in which the Supreme Court rejected efforts to interpret broadly a federal age discrimination law that generally prohibits states from discharging employees over 40 years old due to their age. 501 U.S. 452, 466-67 (1991). In so doing, the Court emphasized that it would be inappropriate to extend this federal prohibition to state judges given that the qualification requirement for judges "is a decision of the most fundamental sort for a sovereign entity" and for which "Congressional interference would upset the usual constitutional balance of federal and state powers" and that, as a result, "'it is incumbent upon the federal courts to be certain of Congress' intent before finding that federal law overrides' this balance." 501 U.S. at 460 (citing *Atascadero*, 473 U.S. at 243).

[24] 461 U.S. 190 (U.S. 1983).

> many years and in great detail by the States. As we noted in *Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council, Inc.*, ... "There is little doubt that under the Atomic Energy Act of 1954, state public utility commissions or similar bodies are empowered to make the initial decision regarding the need for power.' Thus, 'Congress legislated here in a field which the States have traditionally occupied. ... So we start with the assumption that the historic police powers of the States were not to be superseded by the Federal Act unless that was the clear and manifest purpose of Congress."[25]

In *Pacific Gas & Electric*, the Court held that Congress did not make its intentions clear and manifest because the Atomic Energy Act of 1954 only regulated the "safety aspects involved in the construction and operation of nuclear plants" and did not expressly authorize any federal agency to make decisions on the need, cost, reliability, and feasibility of building a nuclear power plant (which are matters traditionally reserved to states).[26] As a result, the Court was unwilling to interpret broadly the Atomic Energy Act to override a Californian law that the Court determined had been adopted to address the "economic problems" that could result from constructing a new nuclear power plant without insufficient spent fuel storage capacity.[27]

On other occasions, however, Congress has made its intentions clear and manifest when enacting federal laws that involve the regulation of electricity generation. One such case is section 201(b) of the Federal Power Act,[28] in which Congress expressly authorized the Federal Energy Regulatory Commission and its predecessor agency, the Federal Power Commission, to regulate the interstate sale of electricity at wholesale, and the transmission of electricity in interstate commerce, but also specified that this jurisdiction did not extend to the generation of electricity.

In addition, Congress developed a number of related federal policies that specifically directed EPA or other federal agencies to encourage the use of coal to generate electricity in response to the energy crises during the 1970's. One such example is the Energy Supply and Environmental Coordination Act of 1974,[29] which authorized the Federal Energy Administrator to issue orders requiring <u>existing</u> power plants to convert from using natural gas or fuel oil to coal for the generation of electricity. Similarly, Congress enacted into law the Power Plant and Industrial Fuel Use Act of 1978,[30] which – among other things – prohibited the construction of any <u>new</u> baseload power plant that did not have "the capability

---

[25] 461 U.S. 190, 205-206 (U.S. 1983) (citations omitted).
[26] 461 U.S. at 190.
[27] 461 U.S. at 222-23.
[28] 16 U.S.C. 824b(b)
[29] The Energy Supply and Environmental Coordination Act of 1974, codified at 15 U.S.C. 792. The authority of the Federal Energy Administrator to issue orders requiring coal conversions expired on December 31, 1978. *See* 15 U.S.C. 792(f).
[30] 42 U.S.C. 8301 et seq.

to use coal or another alternate fuel as a primary energy source."[31] In both cases, Congress provided explicit and unmistakably clear authority to regulate electricity generation, a traditional state sovereign function, in order to conserve the use of natural gas and petroleum for uses other than the generation of electricity.[32]

IV. EPA LACKS AUTHORITY TO ADOPT A PROPOSED NSPS THAT REGULATES THE GENERATION OF ELECTRICITY.

A. The CAA does not contain "unmistakably clear" language authorizing EPA to regulate electricity generation.

As the discussion above indicates, the regulation of electricity generation is a quintessential state sovereign function that EPA has an obligation to respect and preserve. Furthermore, well-established court precedent clearly prohibits EPA from adopting regulations or requirements relating to electricity generation, such as the use of any particular fuel or electric generating technology, unless Congress has adopted "unmistakably clear" statutory language that expressly authorizes EPA to do so. A review of relevant statutory language indicates that neither section 111 nor any other provision of the CAA expressly authorizes EPA to adopt its "no-new-coal" energy policy that would be implemented by the proposed CO_2 NSPS for power plants.

Section 111 of the Act does not reflect a clear and manifest intent of Congress for EPA to adopt performance standards that require the use of any particular fuel or technology.[33] Rather, the statute confines EPA authority to only one matter – the establishment of performance standards for air pollutants emitted from new stationary sources falling within a source category listed for regulation under section 111(b)(1). In particular, section 111(a)(1) directs EPA to establish performance standards that "reflect[ ] the degree of emission limitation achievable through the application of the best system of emission reduction which ... the Administrator determines has been adequately demonstrated." In making this determination, EPA is allowed only to consider "the cost of achieving such reduction" as well as "any non-air quality health and environmental impact

---

[31] 42 U.S.C. 8311(a), (d).

[32] In addition, Congress' clear and manifest intent for the federal government to intrude upon a traditional state sovereign function is further evidenced by a conforming amendment that Congress adopted in 1978 to the Clean Air Act. This amendment clarified that a "coal conversion by reason of an order issued" under the Energy Supply and Environmental Coordination Act of 1974 or other related federal statutory provisions "shall not be a modification" for purposes of the NSPS or New Source Review (NSR) programs. *See* Section 111(a)(8) of the Clean Air Act. Congress added this new provision in order to prevent the stringent NSPS and NSR requirements from preventing or delaying a coal conversion.

[33] In its recent decision in *City of Arlington, Texas et al., v. FCC*, No. 11-1545, decided May 20, 2013 (holding that "courts must apply the *Chevron* framework to an agency's interpretation of a statutory ambiguity that concerns the scope of the agency's statutory authority (i.e. its jurisdiction)"), the Supreme Court held that intrusion on matters of traditional state and local concern was not an issue because the relevant statutory provision explicitly supplanted state authority. Slip op. at 14. No such clear and manifest indication of intent is applicable to EPA's proposal to ban coal use or otherwise regulate the generation of electricity under section 111(b) or any other provision of the CAA.

and energy requirements." However, nothing in section 111 or other provisions of the CAA expressly authorizes EPA to regulate the generation of electricity or other such energy regulatory matters traditionally reserved to states. This lack of express authority confirms Congress' intent to respect and preserve the states' historic role over the regulation of EGUs on electricity generation matters.

The CAA also contains explicit language indicating Congress' clear intent that EPA should not get involved in electricity generation matters relating to the use of any particular fuel or technology. This congressional intent is reflected in section 111(b)(5), which expressly bars EPA from requiring "any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance."[34] In effect, this statutory prohibition makes it crystal clear that Congress has no intent of authorizing EPA to regulate electricity generation, let alone manipulate fuel markets, or to pick winners and losers among alternative electric generation technologies. Picking winners and losers is, transparently, EPA's true purpose here. EPA's proposal would effectively implement a "no-new-coal" energy policy for electricity generation and would do so by adopting a CO_2 performance standard that only NGCC units would be able to achieve.

B. EPA has respected and preserved states' sovereign authority to regulate electricity generation in past NSPS rulemakings.

Since the early 1970's, EPA has adopted NSPS for fossil-fueled power plants on many different occasions. None of these NSPS rules have imposed requirements that regulate electricity generation, let alone ban the future use of coal to generate electricity by new power plants. Moreover, the Agency has not just historically respected and preserved states' sovereign function to regulate electricity generation in past NSPS rulemakings, but has gone to great lengths to adopt performance standards that are technology and fuel neutral.

One notable example is the Subpart Da NSPS that the Agency promulgated for coal-fired EGUs in 1979. In this instance, EPA carefully crafted a stringent SO_2 performance standard that mandated the use of flue gas desulfurization (FGD) systems for the first time, but did so in a manner that would not preclude the use of significant portions of the nation's high-sulfur coal reserves. EPA accomplished this objective by adopting a new SO_2 percent reduction requirement for the FGD system,[35] but retaining the existing SO_2 emissions limitation of 1.2 lbs/MMBtu, as established under Subpart D, for coal-fired EGUs. Notably, EPA's rationale for retaining the current SO_2 limitation was that a more stringent SO_2 standard could preclude the use of "a significant portion (up to 22 percent) of the high-sulfur

[34] This statutory prohibition is subject to one exception for work practices or operational standards under section 111(h) of the CAA, which is not relevant to EPA's proposal. *See* Section 111(a)(5) of the Clean Air Act.

[35] Notably, EPA set a variable SO_2 percent reduction requirement (70 percent to 90 percent reduction) in order to "provide an opportunity for dry SO_2 technology to be developed for all low-sulfur coal reserves." In so doing, the variable NSPS standard "serves to expand environmentally acceptable energy supplies without conveying a competitive advantage to any one coal producing region." 44 Fed. Reg. at 33,583.

coal reserves in the Eastern Midwest and portions of Northern Appalachian coal regions."[36] Specifically, EPA concluded that a tightening of the SO_2 limit – although technically feasible – "could create a significant disincentive against the use of these [high-sulfur] coals and disrupt the coal markets in these regions."[37]

Similarly, EPA has gone to great lengths over the last 40 years not to adopt NSPS limits for any air pollutant that might preclude the use of any particular fuel for the generation of electricity. This was most recently reflected in the revisions to the NSPS that EPA adopted in 2012 for fossil-fueled EGUs. In that prior rulemaking, the Agency concluded it was unreasonable to establish performance standards for conventional air pollutants (*i.e.*, SO_2, NO_x, and PM) that are achievable by only gas-fired power plants. In particular, the EPA provided the following rationale for its conclusion in the response to comments on the final NSPS rule:

> Basing the standards on [natural gas or distillate oil] would result in standards that are neither technically nor economically achievable for a coal-fired [power plant]. Basing the amended standards on the use of natural gas would preclude the development of new coal-fired [power plants] since the standards would not be technically achievable . ... Therefore, basing the NSPS on [natural gas] emissions would not be achievable for coal-fired [power plants] with any technology that EPA is aware of.[38]

For these reasons, the Agency rejected adoption of performance standards based on emissions from a natural gas-fired power plant that would "essentially prohibit the construction of new coal-fired [power plants]."[39]

V. CONCLUSION

In the case of the Clean Air Act, Congress did not provide any specific authority for EPA to adopt federal laws that preempt or otherwise intrude upon traditional state sovereign powers to determine the need for, and economics of electricity generating capacity, or to preclude the use of particular fuels or technologies to generate electricity. Notwithstanding the lack of any such clear and manifest intent of Congress, EPA has attempted to use its general authority under section 111 to regulate emissions from new fossil-fueled power plants in order to adopt a "no-new-coal" energy policy that overrides state energy laws and thereby infringes upon a sovereign regulatory function reserved to the States by the tenth amendment of the Constitution and the federal system. Congress' failure in the CAA to

---

[36] 44 Fed. Reg. at 33,596.

[37] 44 Fed. Reg. at 33,596.

[38] EPA, Response to Public Comments on Rule Amendments Proposed May 3, 2011, Section 2 at 1-2 (December 2011) (herein after referred to as "EPA Response to Public Comments on 2011 NSPS Proposal").

[39] EPA Response to Public Comments on 2011 NSPS Proposal, Section 2, at 2.

provide an explicit "unmistakably clear" authorization for EPA to regulate energy matters pertaining to the use of coal and other fossil fuels to generate electricity is another reason why EPA lacks authority to adopt the proposed CO_2 performance standard that bans the use of coal. For this reason, as well as the reasons presented in AEP's initial comments filed on June 25, 2012, EPA's proposed NSPS rule is fatally flawed and therefore should be withdrawn in its entirety.

AEP strongly supports the decision for EPA to develop a new CO_2 NSPS proposal for new EGUs. In developing that new proposal, EPA must respect and preserve the states' historic role over electricity regulation, and not develop a standard that has the effect of regulating energy production. These matters are quintessentially outside the purview of the regulatory programs entrusted to EPA.

The same limitations apply to any standards developed for modified, reconstructed, or existing sources. And for these standards EPA must keep in mind the broad discretion granted to the states in fashioning programs to implement the federal emission guidelines for existing sources under section 111(d). State energy and environmental authorities can examine any performance standard developed by EPA and determine if more flexible means are available to achieve the same goals at a more affordable cost, without compromising electric reliability, and taking into account the broader economic implications of altering the mix of generating resources within the state. EPA should not foreclose states from exploring such opportunities in the development of plans to implement any standards adopted under Section 111(d), but the timing, stringency, and optimal mix of resources dedicated to achieving the standards adopted by EPA are matters clearly entrusted by Congress to the states.

Should you have any questions or need clarification regarding these supplemental comments, please direct them to me at (614) 716-1268 or Janet Henry, Deputy General Counsel, at (614) 716-1612.

Respectfully Submitted,

John M. McManus
Vice President – Environmental Services
American Electric Power

C: **G. McCarthy, US EPA Administrator**
J. McCabe, US EPA Acting Administrator Air & Radiation
J. Goffman, US EPA Office of Air & Radiation
J. Henry, American Electric Power

Appendix F

AEP Comments Submitted on the Social Cost of Carbon

Comments of American Electric Power

Technical Support Document, Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order No. 12866

Submitted Electronically to: The Office of Management and Budget

Attention: Docket OMB-OMB-2013-0007

February 26, 2014

Summary

American Electric Power (AEP) believes the Social Cost of Carbon (SCC) is inadequate and flawed mechanism to monetize benefits that may accrue from reductions in domestic greenhouse gas emissions. The lack of transparency in model development, lack of peer review, as well as the inclusion of a broad number of unsubstantiated assumptions makes the SCC values developed highly speculative and not appropriate for use in policy development or Regulatory Impact Analysis. Additionally, the post-processing of the Integrated Assessment Model (IAM) results, using averages of various model outputs and scenarios, is completely arbitrary for the evaluation of emission reduction benefits. Furthermore, the model's geographic scope and time period analyzed in development of the SCC values is completely inconsistent with corresponding analysis of regulatory costs. Until these issues can be resolved with firm scientific and public consensus or an alternative valuation system be developed, the SCC should not continue to be used in Regulatory Impact Analysis. AEP encourages the Interagency Working Group to explore alternative systems to more appropriately value carbon costs and benefits in the future.

The Use of Integrated Assessment Models for SCC Value Calculations is Highly Problematic

Underpinning the Social Cost of Carbon values are Integrated Assessment Models (IAMs), which are designed to evaluate the interplay between environmental impacts and economic conditions. These models were developed to explore the possible future trajectories of human and natural systems, answer key questions regarding climate policy development, coordinate assumptions and identify future research needs. As the IAM models are designed for largely exploratory purposes, many of their assumptions and functions still lack a firm routing in proven scientific or economic theory at this point. The Interagency Working Group has pointed this fact out numerous times in the SCC technical documentation and concludes they are in fact "imperfect and incomplete." IAMs are not meant to be predictive tools but rather producers of what-if scenarios of an evolving world.

While the IAM models used to develop the Social Cost of Carbon have been routinely cited in peer-reviewed literature, it is unclear that the models have been subject to direct peer review. As the assumptions play a paramount part in driving the results and conclusions, each assumption parameter and variable needs to be appropriately documented and peer reviewed. This type of work is already done with many models used to calculate policy costs, such as the IPM model used by EPA, and a similar structure should be followed for the IAM models. The lack of consistency and consensus as to these

assumptions is evident in the inconsistent and conflicting results of different model running the same scenarios. As an example, in the low temperate increase scenario, one of the models predicts net benefits while two other models predict significant costs. Furthermore, past assessments of IAM model results have concluded that the calculated climate damages are often derived from very different sources (e.g. market, non-market & catastrophic) suggesting further disagreement and inconsistency.[1] **These conflicts need to be reconciled before the model outputs can be deemed ripe for use in regulatory development or analysis.**

Economic Damage Functions used to Calculate the SCC are Highly Speculative

The IAM models are populated with a chain of assumptions and functions used to translate Greenhouse Gas (GHG) emissions into changes in atmospheric GHG concentrations, GHG concentrations into temperature changes and temperature changes into economic damages. These estimates include economic growth, emissions projections, carbon cycle response, atmospheric concentrations, climate sensitivity, temperature increases, weather effects, and damage functions. The use of damage functions is particularly troubling as there is only a small amount of economic theory and literature to support them and what supporting literature has been developed is not necessarily representative globally. Additionally, the types of damages assessed appear to vary greatly between the three IAM models.

Robert Pindyck perhaps best characterized this situation in stating: "damage functions used in most IAMs are completely made up, with no theoretical or empirical foundation."[2] The Interagency Working Group substantiates these findings concluding there is a "limited amount of research linking climate impacts to economic damages" and that there is "the need for additional research." **However, the avoided economic damages pulled from the IAM models are in fact the sole output that is used to derive SCC values. Thus the SCC values are inherently rooted in incomplete science and economic theory.**

IAM Models Fail to Adequately Account for Climate Adaptation

There is also concern about how the IAMs incorporate adaptation as a means to abate economic damage. First, there is no consistent framework for treating adaptation between the three models, which may account for the significant difference in model results. Also, it appears some abatement opportunities are treated exogenously while others are treated endogenously. Many of these assumptions surrounding abatement appear to be crude and arbitrary with no recognition of increased technical abilities likely to emerge in the future. Additionally, it does not appear abatement opportunities are characterized for each sector in which damages may be calculated. **There needs to be**

---

[1] Joseph E. Aldy, et al, "Designing Climate Mitigation Policy", Resources For the Future, RFF DP 08-16, May 2009. P. 50. http://www.rff.org/RFF/Documents/RFF-DP-08-16.pdf

[2] Robert S. Pindyck, "Climate Change Policy: What Do The Models Tell Us?" National Bureau of Economic Research, Working Paper 19244, July 2013.

further research into adaptation functions to ensure that the estimated damages are not significantly overstating the true economic cost of climate change.

The Emission/Economic Scenarios Bias SCC results to Improbably High Values

Five emission and economic scenarios were modeled in development of the Social Cost of Carbon, based on EMF-22 scenarios, representing a range of emission trajectories. However, four out the five scenarios suggest that emissions will continue to rise largely unabated through 2100, reflecting in the words of the Interagency Working Group, business as usual (BAU) or an emission "pathway absent mitigation policies." This seems widely inconsistent with both current U.S. policy objectives and plausible reality.

Actions by the U.S., European Union, Japan, Australia and a number of other nations to abate emissions show that there is a growing consensus that climate action is taking place and further action is needed going forward. This would suggest that the high emission growth scenarios are likely not to occur due to action already occurring and likely to continue in more substantial fashion going forward with other nations beginning to plan for emission reduction pathways, most notably the world's largest GHG emitter, China.

In the high unlikelihood that large-scale international climate action does not occur in the next few decades, there still remains a large number of years (until the end of the IAM assessment period in 2300) in which to better and more precisely detect actual climatic impacts, characterize future climatic impacts and conclude that emission reduction actions or adaptation measures are needed. These actions could dramatically change the emission and temperature trajectories and thus static assumptions on emission trajectories, particularly those extrapolated post-2100 are highly arbitrary and likely not to transpire. **These conclusions regarding climate action suggest that the BAU scenarios used in SCC development are in fact not likely and are skewing the damages to higher values than otherwise probable.**

The choice of running the IAM model scenarios out to the year 2300 is also concerning. While CO2 has a long atmospheric lifetime and the carbon cycle has inertial effects, making assumptions about socioeconomic factors and climatic factors over such a long time horizon is very tenuous at best. In fact, all data past 2100 is extrapolated, as EMF-22 assumption data ends at that point. To suggest that trends continue in a linear or constant fashion out until 2300 is highly arbitrary. The world of 2300 is likely to look much different that today, thus using assumption and linkages supported by narrow bands of data today may not be technically sound in a much different future. **AEP would suggest using a shorter time for analysis in which the assumptions can be more readily supported.**

U.S. Specific SCC Values should be used for U.S. Regulatory Evaluations NOT Global Values

In addition to the uncertainty in regional IAM model assumptions, inputs and outputs, there no regional differentiation of the ultimate model results. Simply assuming that the U.S. bears a proportion of the global economic damages is highly arbitrary and almost certainly wrong. **Social Cost of Carbon**

values for use in U.S. specific analysis should be derived solely from calculated U.S. economic damages.

Most economists would agree that due to the high level of economic development within the U.S., the U.S. will be better able to adapt and respond to any climatic effects than less developed countries. This suggests using an average marginal global value, in addition to being incorrect in practice, is likely significantly overstating the marginal damages that may accrue to the U.S.

The sensitivity of the results to discount rate indicates that some of the major economic damages may not occur until well into the future. **The undiscounted impacts should be disclosed on a year-by-year basis to allow for evaluation of the timing of impacts over such as long time horizon.** This will better aid policy makers in making balanced policy decisions affecting current society given the uncertainty in the projections. Additionally, there is concern with using discount rates below previous guidance given by OMB.

The Development of SCC Values is Not Analytically Correct

As stated previously, IAMs are not meant to be predictive tools, but rather producers of what-if scenarios in an evolving world. However, in the case of the Social Cost of Carbon, a methodology is employed to use model outputs to produce absolute values regarding the level of carbon abatement that is current economically optimal. **As a result of the SCC development process and the focus on a central value for regulatory analysis, the models are in-fact being used as a predictive tool, which is not what they are designed for.**

The Social Cost of Carbon values are based the average marginal abatement values across the three models and the five socioeconomic scenarios for each discount rate. It is improper to use such a wide range of emission scenarios in the modeling process in the development of the SCC. While there is uncertainty of future international action, as previously commented upon, one must assume that current political efforts and basic human nature in response to impending impacts will in fact result in emission reductions, particularly given the long time horizon for analysis, leading to lower and narrower emission paths than currently assessed. The wide-band of scenarios currently analyzed also accentuates any tail-effects the models may pick up from scenarios with high levels of temperature increase and skew the average.

Due to the inconsistent results and wide range of impacts, averaging the model outputs is a not a statistically sound way to aggregate the data. Extreme values in certain model scenarios drive average values higher. Absent evidence these extreme values not outliers, using a median value approach may be more statistically sound in developing a central value. However the publishing of undiscounted damage values and types of impacts expected would allow for proper assessment of the statistical method required, taking into account risk tolerance.

There is considerable uncertainty as to the proper discount rate to use for intergenerational accounting, but the discount rate used in climate change cost-benefit analysis is highly important given

the fact, that as currently modeled, the majority of damages appear to be loaded in later years. Use of a low discount rate would suggest allocation of current capital resources to emission abatement efforts at the expense of current growth as higher yielding near-term investments might not be allocated capital. This is concerning in light of all the uncertainty in the models. As mentioned previously, several of the discount rates used currently used are lower than OMB guidance.

Costs-Benefits Do Not Match Spatially or Temporally

As mentioned previously, the SCC values are established based on a global measure of benefits. This is inconsistent with current policy as to benefit evaluation of domestic regulation, which is calculated on solely a U.S. basis, based on guidance given through Executive Orders. Potential costs or benefits to other nations are not assessed within analysis of domestic policy. In order for a proper cost-benefit test to be conducted, **both cost and benefit analysis should be conducted with the same geographic scope.** As U.S. regulations are meant to protect the rights of U.S. citizens and residents both costs and benefits should be evaluated on solely the basis of domestic impact. Matching geographic scope is especially important with respect to carbon emissions, as emission leakage is a well-established phenomenon, as discussed later.

The SCC values being developed based on modeling out until the year 2300 also creates a major temporal disconnect between how costs and benefits are evaluated. Typical cost analysis of regulatory proposals only runs for a decade or two at most, with most Regulatory Impact Analyses citing uncertainty or lack of concrete data beyond that point preventing longer-term analysis. **While, it is encouraged that the SCC analysis be truncated well prior to 2300, it also is recommended that assessments of policy costs with respect to carbon take on a similar, longer time-period for analysis, regardless of uncertainty.**

There Will Be Negative Trade Impacts of SCC Use on the U.S. and Emissions Leakage Problems

The SCC values, as currently developed, expose U.S. businesses to a trade disadvantage, as other countries are not using similar carbon values in their policy regimes. Carbon allowances in the European Union and Australia for instance (with limited scope of coverage), trade far below the values that are currently being applied to regulations across all industries in the U.S. in policy analysis. Furthermore, China, a major importer of goods to the U.S., has no national carbon price. As the costs of additional regulation driven by SCC values ripple through the economy, businesses that produce carbon intensive goods will be subject to higher costs and become less competitive. Furthermore, the push to include these SCC valuations in regulatory analysis ignores the fact that U.S. emissions have declined while emissions from developing countries are likely to increase.

International competitiveness will be particularly important going forward with the ongoing development of GHG regulations for the electric sector. As the electric sector is carbon intensive and a large amount of goods produced in the U.S. have value added through electricity, additional costs associated with carbon regulation will translate in to higher domestic production costs. U.S. manufactured goods will be placed at an economic disadvantage to those produced abroad and

production of these goods and corresponding GHG emissions will shift elsewhere. Emission leakage is well-established phenomenon that occurs between markets that place a different value on emissions or reductions. Leakage can also occur through regulation displacing domestic demand for fossil fuels, thus lowering the price and encouraging additional consumption in other sectors and in other countries. These types of shifts in emissions have not been considered to date in Regulatory Impact Analysis. **Without taking into account leakage, forecasting emission reductions in one sector and applying the Social Cost of Carbon will result in an overstating of net emission benefits. This area needs further exploration by the Interagency Working Group and OMB and firm guidance should be provided to address leakage.**

Social Cost of Carbon values can also be routinely updated exposing U.S. industry to never-ending policy uncertainty, which will play havoc on capital allocation. As many of the assumptions and linkages within the model are not well understood, a single variable could change the SCC values quite dramatically. This was recently evident as the updated SSC values were more than 50% larger than those previously published. **Thus, there needs to be a fixed period for peer-review and public comment to update the SCC values. Given capital allocation looks out over a long time horizon, a 10-year review cycle or longer is warranted.**

Cost-Benefit Assessments Must Also Include the Economic Benefits of Lower Cost Energy

Last, the calculation of the social cost of carbon values focuses almost entirely on the negative impacts associated with global climate change and ignores the benefits provided from the use of low-cost energy resources in lieu of more expensive albeit lower carbon alternatives. While the costs of abating emissions are generally picked up as part of a regulatory assessment of costs, the indirect benefits to economic growth, human health and well-being are not typically analyzed. **If an effort is being made to internalize all externalities within cost-benefit analysis, these types of benefits also need to be considered.**

Final Recommendations

The Social Cost of Carbon should not be used in further Regulatory Impact Analysis until outstanding issues regarding its development can be rectified. Among the major issues to be resolved are including public input and peer review of all model assumptions, ensuring calibration and agreement between models, use of narrower emission scenarios, using only projections of domestic damages, truncating model results to be consistent with evaluation of policy costs, providing for appropriate analysis of emission leakage and providing a consistent long-term period for updating of SCC values.

Appendix U_2:

AEP: CCS Lessons Learned Report
American Electric Power
Mountaineer CCS II Project Phase 1

CCS LESSONS LEARNED REPORT

American Electric Power

Mountaineer CCS II Project

Phase 1

Prepared for

The Global CCS Institute

Project # PRO 004

January 23, 2012

Guy L Cerimele, PE, PMP
American Electric Power Service Corporation
1 Riverside Plaza
Columbus, Ohio 43215

Copyright © 2012 American Electric Power Inc. All Rights Reserved

ACKNOWLEDGEMENT

This material is based upon work supported by the US Department of Energy Award Number DE-FE0002673.

The Author would like to thank all who contributed to this report, both directly and indirectly (via incorporation of select content from various work products). The integrated project team involving AEP, Alstom, Battelle and WorleyParsons personnel successfully melded together to form a cohesive project team to deliver on the Phase I requirements of the Department of Energy Cooperative Agreement. The good work of the project team is attributable to many individuals, too numerous to mention herein. The open communications and rapport developed by the team during Phase I is reflected in the many inputs/suggestions of lessons learned, process improvements and exemplary practices that were documented and complied at the end of Phase I- Project Definition Phase.

Copyright © 2012 American Electric Power Inc. All Rights Reserved

DISCLAIMERS

US Department of Energy: This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

American Electric Power: This report is provided "as-is" and with no warranties, express or implied, whatsoever for the use or the accuracy of the information contained therein. Use of the report and the information found therein is at the sole risk of the recipient. American Electric Power Company, its affiliates and subsidiaries, shall not be liable in any way for the accuracy of any information contained in the report, including but not limited to, any errors or omissions in any information content; or for any loss or damage of any kind incurred as the result of the use of any of the information.

Copyright © 2012 American Electric Power Inc. All Rights Reserved

TABLE OF CONTENTS

1. SYNOPSIS 1
2. EXECUTIVE SUMMARY 1
3. INTRODUCTION 2
   - 3.1 About Lessons Learned 2
   - 3.2 Lessons Learned Process 3
   - 3.3 Historical Evolution to Current Project 3
   - 3.4 Project Objectives & Scope 4
   - 3.5 Scope of Lessons Learned 5
4. LESSONS LEARNED, INSIGHTS and EXEMPLARY PRACTICES 5
   - 4.1 Organization of Discussion 5
   - 4.2 Overall Project 5
     - 4.2.1 Lessons Learned 5
     - 4.2.2 Insights 7
     - 4.2.3 Exemplary Practices 7
   - 4.3 Carbon Dioxide Capture 8
     - 4.3.1 Lessons Learned 8
     - 4.3.2 Insights 11
     - 4.3.3 Exemplary Practices 11
   - 4.4 Carbon Storage 12
     - 4.4.1 Lessons Learned 12
     - 4.4.2 Insights 13
     - 4.4.3 Exemplary Practices 14
   - 4.5 Other Miscellaneous 15
5. CONCLUSIONS 15
6. APPENDICES 17
   - 6.1 Compilation of Miscellaneous Technical Lessons Learned for CO_2 Storage 17

Copyright © 2012 American Electric Power Inc. All Rights Reserved

LIST OF REFERENCES

1. CCS INTEGRATION REPORT TO GLOBAL CCS INSTITUTE
2. CO2 COMPRESSION REPORT TO GLOBAL CCS INSTITUTE
3. CO2 STORAGE REPORT TO GLOBAL CCS INSTITUTE
4. FRONT-END ENGINEERING & DESIGN REPORT TO GLOBAL CCS INSTITUTE

Copyright © 2012 American Electric Power Inc. All Rights Reserved

1. SYNOPSIS

The purpose of this report is to share select lessons learned, insights and exemplary practices from American Electric Power's Phase I – Project Definition activity associated with the Carbon Capture and Storage (CCS) system planned for installation at the company's Mountaineer Plant, located in New Haven, West Virginia, USA under US Department of Energy Cooperative Agreement No. DE-FE002673. Notwithstanding American Electric Power's (AEP) decision to dissolve the existing cooperative agreement and postpone project activities, AEP and its integrated project team successfully completed the Phase I effort for the Mountaineer Commercial Scale CCS project.

The front-end engineering and design package developed within Phase I incorporated knowledge gained and lessons learned (construction, operations, and process related) from the 20 MWe pilot Product Validation Facility (PVF) project for both the carbon dioxide (CO_2) capture and storage systems. The design package also established the fit, form, and function of the project including design criteria, mass and energy balances, plot plans, general arrangement drawings, electrical one-lines, process flow diagrams, P&IDs, etc.

The work completed in Phase I continues the advancement of Alstom's CAP technology toward commercial demonstration at the intended scale. The completed front-end engineering and design package also provides a sound basis for completion of the project when conditions warrant the continuation of this or a similar project elsewhere. The lessons learned, insights, and exemplary practices shared within this report should benefit other CCS projects.

2. EXECUTIVE SUMMARY

With a long historical record of delivering many electric utility industry innovations, coupled with a predominantly coal-fired electric generation fleet, AEP took an early leadership role in exploring the feasibility of retrofitting its coal-fired fleet with CO_2 capture and storage technologies. AEP undertook a measured approach in its leadership role that tracked the emergence of dialogue around future CO2-limiting policies in the US and abroad. Among other things, AEP engaged in a cost sharing agreement with the US Department of Energy (DOE) in 2003 to determine the geologic feasibility of storing CO_2 in deep saline reservoirs in the Ohio Valley. Based on the favorable results of the geologic characterization project, AEP selected the Alstom's Chilled Ammonia Process in 2007 for testing of their CO_2 capture technology at a 20 MWe pilot scale. Known as the Product Validation Facility, the project included carbon dioxide injection and deep saline storage. The 2009 proposed scale up of Alstom's Chilled Ammonia Process to a commercial scale project and AEP's financial commitment appeared to be in-sync with emerging US policy aimed at curbing CO_2 emissions. Key for AEP and its ratepayers, was the need to understand both the technical and financial viability of retrofitting coal-fired generation with CCS technology, given the impending emergence of federal legislation.

With the Mountaineer Commercial CCS II project, AEP and the DOE planned a phased approach to its execution with key decision points and phase gate off-ramps inserted at the end of each of Phases I & II. The decision points allowed for reflection of the work performed (e.g. technical and financial feasibility) within the phases and decisions on whether to proceed with subsequent project phases. Given the diminished prospects for future regulatory support and cost recovery due a lack of federal legislation, AEP informed DOE at the Phase I decision point of its intention to dissolve the project agreement and suspend

Copyright © 2012 American Electric Power Inc. All Rights Reserved

further work following the completion of Phase I. At the time of the communication, AEP noted that when the original grant application was submitted by AEP in response to DE-FOA-0000042, AEP believed it important to advance the science of CCS due to pending action regarding climate change legislation and/or regulations concerning CO_2 emissions at its coal-fired power plants. Various bills in Congress were introduced to limit emissions that also provide funding for early CCS projects. AEP also believed that regulatory support for the remaining cost recovery beyond the DOE or legislative support was probable given the potential for emission reduction requirements on an aggressive timetable. While AEP still believes the advancement of CCS is critical for the sustainability of coal-fired generation, the regulatory and legislative support for cost recovery simply does not exist at the present time to fund AEP's cost share of the Mountaineer Commercial Scale Project.

With the completion and documentation of the Phase I work, AEP and DOE have a good understanding of the project's risks; capital costs; and expected operations and maintenance costs. The completed front-end engineering and design package provides a sound basis for completion of the project when conditions warrant the continuation of this or a similar project elsewhere.

As a part of any project close-out, projects and engineering groups within AEP's generation business unit routinely document lessons learned. Lessons learned may consist of activities that were known to have negatively impacted the execution of a project or the performance of an organization or may be activities or events that worked well and had a positive effect. While a number of lessons learned were documented during project execution, most of the lessons learned were documented and compiled at the end of Phase I in a lessons learned meeting that followed an advance survey of project team members for lessons learned inputs. Over 20 participants, representing AEP, Alstom, Battelle and WorleyParsons input and/or participated in the review. Project lessons learned, exemplary practices and recommended process improvement were reviewed for understanding and/or were updated as a result of the meeting discussions. Lessons learned inputs were aggregated into three broad categories: Overall Project General, CO_2 Capture Effort and CO_2 Storage Effort.

The lessons learned discussions contained herein primarily pertain to the Mountaineer commercial scale CCS project. However, given the historical work leading up to and inputting to the commercial scale project a number of discussions draw on AEP's earlier experiences.

While a select number of notable lessons learned, insights, and exemplary practices are highlighted in this presentation, numerous others are shown in an Appendix to this report. The documented lessons learned, insights, and exemplary practices should serve a future project team, if and when the project resumes, others working on DOE funded projects and other CCS projects in general.

3. INTRODUCTION

3.1 About Lessons Learned

Lessons learned may consist of activities that were known to have negatively impacted the execution of a project or the performance of an organization or may be activities or events that worked well and had a positive effect. The projects and engineering groups, within AEP's generation business unit, routinely utilize lessons learned processes in execution of their projects. Through documentation and dissemination of lessons learned, project teams and organizations learn from and avoid the reoccurrence of miss-steps. Additionally, and equally as important, lessons learned processes may extend to the

Copyright © 2012 American Electric Power Inc. All Rights Reserved

identification of exemplary practices and recommended process improvements that help mature performing teams and organizations, increasing their value to and contributing to the bottom lines of their companies.

3.2 Lessons Learned Process

As noted above, lessons learned are routinely documented in the execution of projects. Project teams may be asked to document lessons learned following a specific incident, action or activity. Alternatively, lessons learned are compiled following completion of a short term project of a year or less; or, in the case of a long term project performed over multiple years, they may be compiled following the completion of a project phase (e.g. initial front-end engineering and design, detailed engineering, construction, and start-up and commissioning). As a phased project, the Mountaineer Commercial Scale CCS project (MT CCS II) held a lesson learned meeting following a survey of project team members for inputs in advance of the meeting. Inputs were requested for lessons learned, exemplary practices and process improvements. Over 20 participants, representing AEP, Alstom, Battelle and WorleyParsons input to and/or participated in the review. Project lessons learned, exemplary practices and recommended process improvement were reviewed for understanding and/or were updated as a result of the meeting discussions. The lessons learned, exemplary practices, and recommended process improvements were distributed to the participants and input to AEP's lessons learned data base repository.

AEP also held a separate day-long lessons learned meeting with Battelle to review overall technical related lessons learned from Battelle's support and participation on related carbon storage projects that first started in 2003; descriptions of those projects are contained in Section 3.3.

3.3 Historical Evolution to Current Project

AEP has been actively involved in the development of CCS technology over the past eight years. AEP's initial involvement in the development of CCS began in 2003 with the Ohio River Valley CO_2 Storage Project; US DOE's National Energy Technology Laboratory (NETL) sponsored the project under Contract No. DE-AC26-98FT40418. The project included the drilling, sampling, and testing of a deep well combined with a 2D seismic survey to characterize local and regional geologic features at AEP's Mountaineer plant. The work completed within the project laid the groundwork for site selection of the PVF based on its very detailed geologic characterization study.

In March 2007, AEP signed an agreement with Alstom to validate its Chilled Ammonia Process (CAP) technology via scale up to a 20-MWe Product Validation Facility (PVF). Alstom had previously constructed and operated a 1.7-MWe pilot scale CAP capture facility at the We Energies Pleasant Prairie Power Plant. The flue gas volume of the slip stream for the PVF is equivalent to the flue gas generated from a 20 MWe coal fired power plant. The PVF was designed to capture and store approximately 100,000 metric tons of CO_2 annually.

Captured CO_2 from the PVF was injected via two onsite wells into two geologic formations (Rose Run sandstone and Copper Ridge dolomite) at a depth of approximately 1.5 miles below the plant site. One injection well and three deep monitoring wells were drilled within the power plant property between 2008 and 2009. The characterization well, previously drilled in 2003 was re-worked and transformed into one of the two injection wells. The PVF provided critical data to support the design and engineering of the MT CCS II project.

Copyright © 2012 American Electric Power Inc. All Rights Reserved

In August 2009, AEP submitted an application to Department of Energy (DOE) to demonstrate the commercial viability for retrofitting the Mountaineer plant with a 235-MWe nominal carbon capture and storage facility, building on the work of the DOE supported Ohio River Valley CO_2 Storage Project, and including the non-DOE funded PVF. In December 2009, DOE announced the selection of the Mountaineer Commercial Scale Carbon Capture and Storage Project for funding under Round Three of the DOE's Clean Coal Power Initiative.

3.4 Project Objectives & Scope

AEP's objective for the MT CCS II project is to design, build, and operate a commercial scale carbon capture and storage (CCS) system capable of treating a nominal 235 MWe slip stream of flue gas from the outlet duct of the Flue Gas Desulfurization (FGD) system at the Mountaineer Plant, a 1,300 MWe coal-fired generating station located in New Haven, West Virginia. The CCS system is designed to capture 90% of the CO_2 from the incoming flue gas using the Alstom's CAP and compress, transport, inject and store 1.5 million metric tons per year of the captured CO_2 into deep saline reservoirs.

AEP and its integrated project team, including Alstom, Battelle and WorleyParson successfully completed the Phase I effort for the Mountaineer Commercial Scale Carbon Capture and Storage Project in accordance with US DOE Cooperative Agreement No. DE-FE002673, which provided 50% cost sharing to the project. Phase I of the project's cooperative agreement called for, among other things: the completion of front-end engineering and design (FEED); the development of an Environmental Impact Statement in accordance with the National Environmental Process Act (NEPA); and the identification of exceptionally long lead time items.

The front-end engineering and design package developed within Phase I incorporated knowledge gained and lessons learned (construction and operations related) from the PVF and the design package also established the fit, form, and function of the project including design criteria, process flow diagrams, mass and energy balances, plot plans, general arrangement drawings, electrical one-lines, flow diagrams, P&IDs, etc.

Based on the work completed in the front-end engineering and design package, AEP and its integrated project team also:

- Developed a +/- 25% cost estimate,
- Developed a detailed Phase II project schedule,
- Provided DOE with all information it needed to complete the NEPA process,
- Developed a multi prime construction contracting strategy for Phase III,
- Drilled a deep well for characterization of subsurface geology at one of the remote CO_2 storage sites,
- Issued preliminary PFD and overall mass and energy balances, and
- Completed preliminary project design.

Copyright © 2012 American Electric Power Inc. All Rights Reserved

3.5 Scope of Lessons Learned

The lessons learned discussions contained herein primarily pertain to the MT CCS II project. However, given the historical work leading up to and inputting to the MT CCS II project a number of discussions draw on AEP's earlier experiences. Specifics of lessons learned relating to Alstom's Chilled Ammonia Process technology are not addressed in this report due to the proprietary nature of that information; generalities are however noted consistent with the referenced topical project reports previously prepared for the Global CCS Institute. Specifics of a number of lessons learned pertaining to the work on CO_2 storage systems are however shared in this report.

While this report is titled a CCS Lessons Learned Report, the discussions contained herein also include insights and advice and discussion of exemplary practices.

4. LESSONS LEARNED, INSIGHTS AND EXEMPLARY PRACTICES

4.1 Organization of Discussion

The lessons learned discussions, insights, exemplary practices and other advice shared within this section are organized along broad classifications of: Overall Project General, Carbon Dioxide Capture Systems, and Carbon Dioxide Storage Systems. Select lessons learned are noted and discussed, while other lessons learned are listed in appendices. Within the broad classifications, the lessons learned discussed that are listed in the appendices may be further subcategorized by subject area (e.g. engineering/technical, regulatory, environmental, construction, project management, communications, etc).

The format employed for presenting the subject mater includes:

- A statement or description of the lessons learned, insight or exemplary practice;
- A recommendation for any listed lesson learned; and
- Discussion, as applicable for understanding and context for the lesson learned, insight or exemplary practice.

The lessons learned insights and exemplary practices listed and discussed in the sections to follow are judged to be some of the more significant issues worthy of listing and discussion; they are however randomly listed within the broad categories and are not shown in any prioritized ranking.

4.2 Overall Project

4.2.1 Lessons Learned

4.2.1.1 LACK OF FEDERAL LEGISLATION RELATED TO CO_2 EMISSIONS

Recommendation - Dissolve the existing cooperative agreement at the appropriate project phase decision point and postpone project activities.

Discussion - At the Phase I decision point to DOE, AEP communicated its plans to dissolve the existing cooperative agreement and postpone project activities following the completion of Phase I. At the time of the communication, AEP noted that when the original grant application was submitted by AEP in

Copyright © 2012 American Electric Power Inc. All Rights Reserved

response to DE-FOA-0000042, AEP believed it important to advance the science of CCS due to pending action regarding climate change legislation and/or regulations limiting CO_2 emissions at its coal-fired power plants. Various bills in Congress were introduced to limit emissions but also provide funding for early CCS projects. The Waxman-Markey Bill even passed the House but later failed to pass the Senate. AEP also believed that regulatory support for the remaining cost recovery beyond the DOE or legislative support was probable given the potential for emission reduction requirements on an aggressive timetable. While AEP still believes the advancement of CCS is critical for the sustainability of coal-fired generation, the regulatory and legislative support for cost recovery simply does not exist at the present time to fund AEP's cost share of the Mountaineer Commercial Scale Project.

4.2.1.2 PREPARATION OF THE ENVIRONMENTAL IMPACT STATEMENT (EIS) REQUIRED MORE UPFRONT TECHNICAL OR ENGINEERING INFORMATION THAN WAS INITIALLY AVAILABLE

Recommendation - Start engineering and hire the National Environmental Policy Act (NEPA) contractor as soon as practicable. Build 18 to 24 months into the project schedule for the NEPA process.

Discussion - Compiling information and having an Environmental Impact Statement (EIS) prepared is an intensive effort that requires the completion of some engineering to start the EIS development process. Environmental Impact Statements written around processes that are somewhat first-of-a-kind or new can add challenges to the NEPA process as many of the analyses and evaluations in the EIS require significant information from the process or technology. Since commercial scale CCS had not yet been demonstrated in practice, much of the technical information was based on calculated values, modeled effects, and assumptions.

4.2.1.3 CARBON DIOXIDE CAPTURE RETROFIT SYSTEMS MAY NOT BE PRACTICABLE FOR PLANT SITES LACKING AVAILABLE AREA FOR THE PROCESS EQUIPMENT

Recommendation – Recognize that carbon capture retrofit installations require significant space for installation and operations.

Discussion – The design for the MT CCS II project covers about 13 acres of plant property adjacent the existing 1300 MW unit. As a first-of-a-kind (FOAK) retro-fit facility, the design for the project includes buildings for visitor presentations, administrative staff, a laboratory and added warehouse space. The need for the additional buildings may or may not be applicable to other installations, based on their site specific circumstances. That being said, the amount of space needed for the retrofit project was a significant revelation to AEP; fortunately the Mountaineer plant site is not constrained by a lack of available space.

4.2.1.4 THE PROJECT TEAM GAINED A GREATER APPRECIATION FOR THE BENEFITS OF PERFORMING EARLY HAZARDS ANALYSES AND CONSTRUCTABILITY REVIEWS

Recommendation - Incorporate hazards analyses and constructability reviews in FEED activities.

Discussion – AEP's Engineering, Projects and Field Services organization continually strives to improve its recognition of hazards and incorporation of safety into its designs. Additionally, efforts to involve construction personnel in constructability reviews during front end engineering & design has had limited

Copyright © 2012 American Electric Power Inc. All Rights Reserved

success, primarily due to limited resources availability. As a FOAK project with many perceived hazards and concerns for first time construction of such a project, AEP and its integrated project team focused significant effort and resources to identify and address hazards and constructability issues. The effort and time spent proved far more valuable than anticipated contributing to, among others: the early identification and the efficient addressing of hazards during the FEED process; early identification of constructability concerns that led to cost savings opportunities; and a more robust cost estimate and construction schedule.

4.2.2 Insights

4.2.2.1 IN A FOAK APPLICATION, TRY TO INNOVATE FROM PROVEN TECHNOLOGIES

Discussion – FOAK applications or projects inherently carry a number of unknown uncertainties or risks, or in other words you don't know what you don't know until it happens. It's important to limit uncertainties or risks associated with new or unproven technologies without track records. A significant portion of the process equipment making up the CAP is readily used in the petrochemical industry. While scaling up the equipment design often led to a multiple process "train" approach within the broader process, the equipment considered for MT CCS II was not un-proven in industrial or petrochemical applications.

4.2.2.2 THE GREATEST COST RISKS FOR CCS PROJECTS MAY LIE IN THE STORAGE SIDE OF SUCH PROJECTS

Discussion – AEP and its integrated project team performed a critical review of the MT CCS II project cost estimate for application of risk based project contingency. AEP examined the CO_2 capture system cost estimate, and generally felt that the estimate contained more opportunities for cost savings than risks of cost increases. The greatest uncertainties and corresponding risks for cost increases were in the carbon storage side of the project, principally due to uncertainties associated with interpretation and application of the new Class VI Underground Injection Control (UIC) permit regulations for injection, monitoring and post closure care of carbon storage sites. Additional detailed discussion for this insight is contained in the Front-end Engineering and Design report on the MT CCS II project prepared for Global CCS Institute at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project>.

4.2.3 Exemplary Practices

4.2.3.1 HIGH RISK AND FOAK PROJECTS AND/OR PROGRAMS NEED TO BE CAREFULLY MANAGED FROM INCEPTION THROUGH PILOT TESTING AND COMMERCIAL DEMONSTRATION WITH STRATEGICALLY PLACED DECISION POINTS AND PHASE GATE OFF-RAMPS

Discussion – With a long historical record of delivering many electric utility industry innovations, coupled with a predominantly coal-fired electric generation fleet, AEP took a leadership role in exploring the feasibility of retrofitting its coal-fired fleet with CO_2 capture and storage technologies. AEP undertook a measured approach in its leadership role that tracked the emergence of dialogue around future CO_2-limiting policies in the US. As noted in the introduction, AEP first engaged in a cost sharing agreement with the DOE to determine the geologic feasibility of storing CO_2 in deep saline reservoirs in the Ohio

Copyright © 2012 American Electric Power Inc. All Rights Reserved

Valley, home to a number of AEP coal-fired generating plants. Based on the favorable results of the geologic characterization project, AEP selected the Alstom CAP for pilot testing of carbon dioxide capture and included CO_2 storage in the PVF project. The scale up of Alstom's CAP to a commercial scale project and AEP's financial commitment appeared to be in-sync with emerging US policy on limiting CO_2 emissions. Key for AEP and its ratepayers, was the need to understand both the technical and financial viability of retrofitting coal-fired generation with CCS technology, given the impending emergence of federal legislation.

With the Mountaineer CCS II project, AEP and the DOE planned a phased approach to its execution with key decision points and phase gate off-ramps inserted at the end of each of Phases I & II. The decision points, allowed for reflection of the work performed (e.g. technical and financial feasibility) within the phases and collective decisions on whether to proceed with subsequent project phases. Given the diminished prospects for future regulatory support and cost recovery due a lack of federal legislation, AEP informed DOE at the Phase I decision point of its intention to dissolve the project agreement and suspend further work following the completion of Phase I.

With the completion and documentation of the Phase I work, AEP and DOE have a good understanding of the project's risks; capital costs; and expected operations and maintenance costs during planned Phase IV operations. The completed front-end engineering and design package provides a sound basis for completion of the project when conditions warrant the continuation of this or a similar project elsewhere.

4.2.3.2 COMMUNICATE OFTEN WITH THE PUBLIC

Discussion – Be sure to develop a communications plan for your project and ask plant employees that live in nearby communities to review and comment on it before rolling it to the public. Plan for and conduct meetings with local government and public officials before the start of major work on site; include public open houses and/or town hall meetings to describe the project and address any concerns. AEP held annual town hall meetings to update community leaders on project status and plans for the upcoming year. Example presentations or discussions might include among others, an exhibit showing the type of truck and geophone used to perform 2D seismic studies (e.g. noise from pounding the ground and tracking energy waves) and a heads-up of crew schedules for walking down proposed CO_2 pipeline transport corridors.

4.3 Carbon Dioxide Capture

4.3.1 Lessons Learned

4.3.1.1 CARBON DIOXIDE CAPTURE SYSTEMS ARE CHEMICAL PLANTS THAT HAVE A DIFFERING OPERATING PHILOSOPHY THAN ELECTRIC POWER PLANTS

Recommendation – The CO_2 capture technology provider and electric utility owner need to recognize and address operational philosophy differences and process dynamics limitations early in the design process.

Discussion - Power plants and chemical plants have differing operational philosophies. Examples include: 1) chemical plants produce a uniform product from a uniform feed stock whereas power plant

Copyright © 2012 American Electric Power Inc. All Rights Reserved

electrical energy production is based on demand closely tied to weather; 2) chemical plants have stable production rates with consistent production schedules whereas power plants have frequent power output adjustments based on time of day and load following; and 3) coal-fired power plants have a variable fuel feedstock whereas variability of feedstock to chemical plants is minimized to reduce impacts. Additional issues include: access, maintainability related to outage durations, and safety policies that added to cost; see the referenced CCS Integration report for additional detailed discussion at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project>.

4.3.1.2 SOURCING AND QUALITY OF STEAM IS IMPORTANT

Recommendation – Carefully consider the extraction source(s) of steam relative to the needs for the CO_2 capture retrofit system; depending on the size of the carbon dioxide capture system, a stand alone or independent steam supply source may be more desirable.

Discussion – As discussed at length in the CCS Integration Report at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project>, the project team decided to extract steam at two different pressure levels and utilize throttling valves for supply of steam to the carbon dioxide capture regeneration and process stripping systems. The selection points and quality of steam supply met the needs for the system at the intended scale-up size. However, if one were to design a commercial scale system capable of treating the entire flue gas discharge, and independent steam supply source would need to be considered. It must be understood that selection of the steam source is highly site-specific and project-specific. Because this was a slipstream demonstration project, AEP was reluctant to accept significant modifications to the steam turbine that could have impacted future operations once the CCS project was completed. That design criteria then factored into the overall decision of where to extract steam.

4.3.1.3 UNCLEAR CRITERIA FOR OPERATIONS VERSUS CAPITAL COSTS CAN LEAD TO REANALYSIS AND DELAY.

Recommendation - Establish criteria for operating versus capital costs early in the project.

Discussion – Early consideration of evaluation criteria (e.g. reliability, maintainability and availability) by owner and technology provider teams helps avoid later focus on the wrong driver for a design decision.

4.3.1.4 INSURE THAT PRELIMINARY EQUIPMENT SIZING CAN BE PRACTICABLY FABRICATED AND SHIPPED TO SITE.

Recommendation – Work with one or more potential equipment suppliers during initial design.

Discussion – FOAK system projects, in a scale-up stage will lead to new sizing or reconfiguration of equipment. Equipment suppliers will likely have insights regarding practical limitations of sizing and/or cost savings ideas for reconfiguration of equipment subsystems or components. The challenge to the FOAK technology and/or overall project owner is to determine when it may be in the best interests of the project to involve equipment suppliers in early design discussions, including the need to compensate them for resources utilized in providing the inputs.

4.3.1.5 A DEDICATED EXHAUST STACK MAY BE PREFERRED AND/OR REQUIRED

Copyright © 2012 American Electric Power Inc. All Rights Reserved

Recommendation – Carefully consider the need for a new dedicated exhaust stack, including the lead time needed for permitting.

Discussion – As discussed in more detail in the CCS Integration report at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project>, the project team considered use of the existing plant stack, construction of a new stack and also possible use of the existing plant hyperbolic cooling tower as an exit point for the treated gas stream. While the team initially recommended a new dedicated stack, uncertainties and lead times associated with modeling and permitting of a new stack became a disincentive. The team returned treated gas back to the existing plant stack as a basis for the project cost estimate. However, for treating higher percentages of flue gas, a dedicated exhaust point may be required as the technical difficulties surrounding mixing of flue gas streams and gas stream temperatures may become a concern.

4.3.1.6 GRAY WATER MANAGEMENT IS A SIGNIFICANT CHALLENGE

Recommendation – Turn gray water into a marketable product

Discussion – The gray water by-product bleed stream, containing ammonium sulfate, can be made into a marketable product as feedstock for manufacture of fertilizer. For Mountaineer's gray water to be considered desirable, the concentration of ammonium sulfate solution needed to be at least 40%. Contacting potential end users early in the design process to better understand the types of products they can utilize can prove beneficial. As an aside, fresh water make-up for evaporation and losses did not require additional make-up capacity at Mountaineer. Again this is project specific, but avoiding the expense and balance of plant related impacts of adding make-up water capacity were significant factor in the overall design process.

4.3.1.7 AEP EVALUATED A NUMBER OF REAGENTS FOR THE CHILLED AMMONIA PROCESS

Recommendation - Anhydrous Ammonia is the optimal reagent for the CAP.

Discussion – The project team evaluated a number of reagents for use in the CAP refrigeration system. The chilled ammonia process uses ammonia solution as chemical solvent to remove CO_2 from the flue gas. Ammonia is the single natural refrigerant being used extensively in industrial applications for its good thermodynamic and thermophysical characteristics. While ammonia is an excellent refrigerant, it is also a hazardous substance. Although hazardous, there are well established practices, common in industry, for the safe handling of anhydrous ammonia. The evaluation and comparisons carried out by the project team showed that an ammonia refrigeration system is optimal for the Mountaineer CCS II project. This system has the lowest energy consumption (highest efficiency) and the lowest installed capital cost, with minimal environmental impact with respect to ozone depletion, greenhouse effect, or global warming.

4.3.1.8 ASSUMPTION OF HIGH CO_2 INJECTION WELL PRESSURES

Recommendation – CO_2 compression to an intermediate pressure, followed by variable speed pumping to the final injection pressure offers the greatest flexibility and efficiency over the life of the system as compared to full compression to the maximum expected injection pressure.

Discussion – Injection well pressures in the range of 1200 – 1500 psi range are expected early in the life of the target injection wells. Maximum injection pressure into the geological formations targeted for this

Copyright © 2012 American Electric Power Inc. All Rights Reserved

project is expected to be 3000 psi. It should be noted that the allowable maximum injection pressure depends on the permitting agency and the fracture gradient of the reservoir and the cap rock. See the referenced CO2 Compression Report for additional discussion at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project>.

4.3.2 Insights

4.3.2.1 BUILD FLEXIBILITY INTO PLANT INTERFACE POINTS TO ALLOW FOR AND/OR ACCOUNT FOR UPSET CONDITIONS.

Discussion – The CCS integration report, furnished to Global CCS Institute at <http://www.globalccsinstitute.com/projects/mountaineer-commercial-scale-carbon-capture-and-storage-project> discusses at length AEP's approach for integrating FOAK retro-fit technologies and the need to build flexibility into plant interface points. Design basis for plant interface points can be refined later based on operating experience.

4.3.3 Exemplary Practices

4.3.3.1 INVOLVE APPROPRIATE PLANT PERSONNEL IN ALL DISCUSSIONS SURROUNDING CRITICAL INTERFACE POINTS (E.G. STEAM TURBINE, RIVER WATER INTAKE, AND OTHER CRITICAL PROCESSES)

Discussion – Plant personnel have greater awareness for and key insights regarding operational flexibility of their plant systems. Involvement of plant personal from the onset of the project contributed to a higher confidence of the design basis, improved communication of ideas, and minimized obstacles to plant understanding and acceptance.

4.3.3.2 THE PROJECT TEAM'S USE OF A 3D MODEL DURING PRELIMINARY PROJECT DESIGN PROVIDED NUMEROUS BENEFITS

Discussion – The 3D model developed for the project proved to be invaluable to the integrated project team. As the model was developed, it was reviewed on a monthly basis by project team members representing, among others: construction, engineering, plant personnel, and project management. The model not only helped with understandings of equipment sizing and relationships to existing plant infrastructure, but it also helped the team develop a detailed materials list and robust cost estimate; as an example, the team was able to account for piping sizes down to a 2-1/2 inch (6.35 cm) diameter. The model also aided project constructability reviews. Overall, the project team felt that the use of the model increased everyone's confidence in the final project cost estimate.

4.3.3.3 AEP AND ALSTOM COLLOCATED ENGINEERING PERSONNEL AND UTILIZED INTEGRATED PROCESS DESIGN WORKSHOPS

Discussion – The start of design for the MT CCS II project overlapped with the operation of the PVF. As a result, lessons learned from the PVF were still being revealed and/or compiled during early MT CCS II design activity. AEP and Alstom decided to collocate engineering and plant personnel, alternating in offices both in the US and in Europe, to speed an in depth understanding and application of the lessons

Copyright © 2012 American Electric Power Inc. All Rights Reserved

learned from the PVF. The process design workshops helped speed the integrated project team's collective understanding of capture subsystems in a way that allowed for transparency and buy-in from plant personnel that ultimately would be tasked with operation of the systems. The process design workshops also contributed to a higher level of confidence for the overall system design.

4.4 Carbon Dioxide Storage

4.4.1 Lessons Learned

4.4.1.1 CO_2 INJECTION AND MONITORING WELLS ARE NOT "BUSINESS AS USUAL" FOR ANY REGULATOR.

Recommendation - Partner with regulators and others as needed early in the permitting process.

Discussion - Underground Injection Control (UIC) regulations, promulgated by the US Environmental Protection Agency (EPA) are new and may be unfamiliar to state regulators. States targeted for CCS projects will also need to develop their own regulations to comply with US EPA requirements before they can be authorized to process and permit CO_2 storage projects.

4.4.1.2 THE PROJECT TEAM DID NOT HAVE AN APPRECIATION FOR NECESSARY LEAD TIMES TO SECURE PROPERTY ACCESS RIGHTS FOR LOCATING CO_2 TRANSPORT PIPELINES.

Recommendation – Involve land management professionals early in the development of any project schedule.

Discussion – The project team did not have an appreciation for the lead times necessary to secure property access rights, causing some schedule delay. Land management personnel should be consulted when developing the Level I or II inputs to the overall project schedule. In a related matter, project team incorrectly assumed that the location of transport pipe lines within right-of-ways for transmission lines would lessen permitting needs.

4.4.1.3 THE DRILLING SCHEDULE DID NOT ACCOUNT FOR COMMON RISK FACTORS THAT CAN IMPACT THE PLANNED SCHEDULE OF COMPLETION.

Recommendation – Acknowledge risk factors in the drilling operation and incorporate them into the schedule.

Discussion – The drilling of the BA-02 characterization well proceeded on a tight schedule that in hind site was optimistic and did not consider common risk factors associated with drilling deep wells. Example risk factors might could include among others: failed parts and machinery and the need to maintain adequate spare parts onsite or in close proximity, encountering fluid when drilling on air, encountering excessive fluids in formations, loss of circulation during cementing, fishing tools out of a bore hole, etc. Project teams should work with their drilling crews to anticipate possible risk factors and their probabilities for occurrence and build an appropriate level of contingency into the overall schedule for drilling, and project schedule as applicable.

Copyright © 2012 American Electric Power Inc. All Rights Reserved

4.4.1.4 NEW GEOLOGIC HORIZONS MAY AVAIL THEMSELVES AS BONA FIDE CO_2 STORAGE TARGETS

Recommendation – Consider, to the extent practicable, the drilling of multiple characterization wells over an expanded area.

Discussion – Based on the drilling of the BA-02 characterization well and the subsequent down hole testing, the project team confirmed the Lower Copper Ridge zone was viable beyond the area immediately surrounding the Mountaineer Plant. Prior to work at Mountaineer, this zone was not previously understood to have characteristics suitable for CO_2 storage.

4.4.1.5 GEOPHYSICAL TECHNIQUES SUCH AS SURFACE SEISMIC HAVE RESOLUTION LIMITATIONS

Recommendation – Reservoir testing is crucial during the characterization process.

Discussion – Surface seismic techniques cannot resolve thin horizons. The formations in the Mountaineer plant area are only approximately 30 ft (10 m) thick. Detailed log analyses (which have high resolution of approximately 1ft) and subsequent hydrologic testing of the target reservoirs were crucial in calculating the storage potential of the formation.

4.4.2 Insights

4.4.2.1 INSURE THAT STATE LEVEL POLICIES ARE IN PLACE TO SUPPORT CO_2 INJECTION AND STORAGE; LEAD TIMES TO DO SO CAN SPAN MANY YEARS.

Discussion - CO_2 injection and storage could become cost prohibitive without state level policies, in the form of enabling legislation and regulations that frame the responsibilities and rights of the entities that inject CO_2 and adjacent property owners, respectively. State policies should address, from among other issues: financial responsibility, use of pore space, property rights, liability, eminent domain and permitting fees. Additionally, project teams need to consider the possible migration of injected CO_2 into other regulatory jurisdictions (i.e. adjacent states), as many coal-fired electric utility plants are located along rivers that form boundaries with other state regulatory jurisdictions.

The lead time necessary to develop state level policies, in the form of legislation and regulations can approach three to four or more years, depending on the extent of stakeholder interest and the overall priorities of state executive and legislative branches. For example, AEP has been working with West Virginia policy makers and other stakeholders on CCS issues for over four (4) years. During the 2009 legislative session, the West Virginia Legislature passed a bill acknowledging that it is in the public interest to advance the implementation of carbon dioxide capture and sequestration technologies into the state's energy portfolio. Recognizing the administrative, technical and legal questions involved in developing this new technology, the Code authorized the West Virginia Department of Environmental Protection Secretary to establish a Carbon Dioxide Sequestration Working Group (Working Group). The Working Group was charged with studying all issues related to the sequestration of carbon dioxide and to submit a preliminary report to the Legislature on July 1, 2010, followed up by a final report on July 1, 2011. The preliminary and final reports were delivered to the legislature. The final report, however, addresses, among other things recommended legislation to help encourage the widespread use of CCS

Copyright © 2012 American Electric Power Inc. All Rights Reserved

in West Virginia. Proposed legislation still needs to be introduced and considered by the legislative body; a process that can take one or more years to complete.

4.4.2.2 LEADING CCS PROJECTS NEED TO ACCOUNT FOR UNCERTAINTY WITH FIRST TIME APPLICATION OF UNDERGROUND INJECTION CONTROL (UIC) PERMITTING GUIDELINES.

Discussion – An initial Class VI UIC permit application for a CCS project has yet to be submitted and approved by any state regulatory jurisdiction within the US. Initial review and approval of first time permit applications in any state could become subject high stakeholder interest and prolonged agency review, leading to schedule delay. Additionally, uncertainty regarding the number of shallow, intermediate and deep monitoring wells that might be required by a first UIC permit issuance must be accounted for in project cost estimate assumptions and risks until such time that a UIC permit is received.

4.4.2.3 LOOK FOR OPPORTUNITIES TO PURCHASE PREVIOUSLY COMPLETED 2D SEISMIC STUDIES IN AN AREA OF INTEREST.

Discussion – AEP purchased two 2D seismic lines to enhance its understanding of the regional geology, at a cost savings to the project. AEP also began to appreciate the potential to partner with other area projects that may be drilling in the area (e.g. shale gas exploration). Example partnering arrangements might include exchanging logging data, funding additional drill rig time and effort to perform various optional characterization tests at other nearby drilling sites, etc.

4.4.2.4 CONSIDER THE NEED TO ESTABLISH SITE SELECTION CRITERIA TO EVALUATE PROPERTIES FOR THE WELLS AND PIPELINE CORRIDORS.

Discussion – AEP's selection of candidate well injection sites focused on: property owned by the company in West Virginia; locations which required minimal right-of-way interferences for pipelines and access to the sites; and sites within relative close proximity to the Mountaineer plant. In the course of building a cost estimate for the project, it became apparent that some sites, on closer inspection, had significant developmental costs for access. In retrospect, the project team may have benefitted from having developed site selection criteria based on input from a multi-discipline team (e.g. engineering, environmental, geology, legal, project management). Future projects should consider the need to establish site selection criteria and apply the criteria as early as possible in the conceptual design phase of the project.

4.4.3 Exemplary Practices

4.4.3.1 FORM AND UTILIZE A GEOTECHNICAL EXPERTS ADVISORY GROUP

Discussion - Public acceptance of carbon dioxide storage depends in part on a thorough characterization and assessment of the underlying geology, including the ability of target reservoir zones to receive and store CO_2 without impact to the groundwater resources. AEP expected that, not only would the project development be more robust, but also the public would be more accepting of the ultimate design for the CO_2 injection and monitoring program if a geotechnical advisory group was formed from a wide ranging group of interested and knowledgeable stakeholders (i.e. experts) to broaden and bolster

Copyright © 2012 American Electric Power Inc. All Rights Reserved

the resource expertise levels that were applied to the project, and include their input to the design philosophy and permitting strategy.

4.5 Other Miscellaneous

AEP also held a separate day-long lessons learned meeting with Battelle to review overall technical related lessons learned from Battelle's support and participation on AEP related carbon storage projects that first started in 2003; select technical lessons learned from the Battelle meeting were compiled and are shown in an Appendix 6.1.

5. CONCLUSIONS

Notwithstanding AEP's decision to dissolve the existing cooperative agreement and postpone project activities, AEP and its integrated project team successfully completed the Phase I effort for the Mountaineer Commercial Scale Carbon Capture and Storage Project, as outlined in the cooperative agreement. Within Phase I, the cooperative agreement called for:

- The resolution of outstanding conditions with the U.S. Department of Energy (DOE) cooperative agreement;
- Project specific developmental activities (i.e., front-end engineering and design);
- The initiation of the NEPA process; and
- The identification of exceptionally long lead time items.

The front-end engineering and design package developed within Phase I incorporated knowledge gained and lessons learned (construction and operations related) from the PVF and the design package also established the fit, form, and function of the project including design criteria, mass and energy balances, plot plans, general arrangement drawings, electrical one-lines, flow diagrams, P&IDs, etc.

Based on the work completed in the front-end engineering and design package, AEP and its integrated project team also:

- Developed a +/- 25% cost estimate,
- Developed a detailed Phase II project schedule,
- Provided DOE with all information it needed to complete the NEPA process,
- Developed a multi prime construction contracting strategy for Phase III,
- Drilled a deep well for characterization of subsurface geology at one of the remote CO_2 storage sites,
- Issued preliminary PFD and overall mass and energy balances, and
- Completed preliminary project design.

The work completed in Phase I continues to support positive advancement of the Alstom CAP technology toward commercial demonstration at the intended scale. The work completed also provides AEP and DOE with a good understanding of the project's risks, capital cost, and expected operations and maintenance costs for planned Phase IV operations. The completed front-end engineering and design package provides a sound basis for completion of the project when conditions warrant the continuation of

Copyright © 2012 American Electric Power Inc. All Rights Reserved

this or a similar project elsewhere in the US and the lessons learned, insights, and exemplary practices shared within this report should benefit other CCS projects.

Copyright © 2012 American Electric Power Inc. All Rights Reserved

6. APPENDICES

6.1 Compilation of Miscellaneous Technical Lessons Learned for CO_2 Storage

(Note: Some of the items discussed below have their origins in previous work done by AEP outside the scope of this project. AEP used the knowledge gained in earlier work to further enhance the value of this commercial-scale project and build upon those earlier foundations. It is AEP's contention that sharing such information in this document is of great benefit to future project efforts AND, THUS, WHY THEY HAVE BEEN INCLUDED.)

Well Design:

- Larger diameter tubing in injector wells aided in CO_2 deliverability to the reservoir. Also, larger diameter injection tubing should help to avoid plugging issues and allow a more diverse suite of wire line tools to be run.
- The annular system may need to be reworked so as to avoid future mineral precipitation in the injection tubing string. This may include:
    - Detection and prevention of tubing damage during installation
    - Sensitive annulus pressure or fluid level detectors for sensing minute leaks of annular fluid out of the annular space
    - Use of annular fluid that is less likely to precipitate minerals in a dry (CO_2) environment (e.g. KCl weighted fluid is more expensive but has lower potential for mineralization than CaCl)
    - Periodic injections of water, or some fluid, for removal/dissolution of minerals from injection tubing
    - Use of scale inhibitors in injection tubing
    - Use of tubing material that inhibits coalescence of precipitates
    - Use of larger diameter injection tubing (i.e. tubing with larger minimum ID restriction)
- Real-time down hole temperature and pressure gauges are difficult to work around; may look at "wireless" options in the future
- May want to look at a horizontal injection well option in lower permeability formations (e.g. Rose Run)
- May look at multi-completion monitoring wells for monitoring in separate reservoirs – instead of having one monitoring well per reservoir
- The small diameter of AEP-1 was an issue, particularly since this well was used as an injection well. In this case, this was due to the fact that this well was not originally designed to be an injection well, but rather a characterization well. Nevertheless, avoid small diameter wells in the future.
- Stainless steel casing requires special running equipment, including high torque power tongs and special dies.

Permitting:

- Class VI regulations require a separate UIC permit application for each injection well (no area permits). In addition, five (5) companion plans must be prepared and submitted with the permit application, including: Area of Review and Corrective Action Plan; Testing and Monitoring Plan;

Copyright © 2012 American Electric Power Inc. All Rights Reserved

Emergency and Remedial Response Plan; Well Plugging Plan; Post Injection Site Care and Site Closure Plan.

- Financial assurance requirements under Class VI regulations require payment up front to cover 50 years of post injection monitoring, corrective action, well plugging, and other items. This must be arranged by the time the UIC permit application is submitted.

Drilling:

- Use Geotech/pilot hole to help guide conductor/surface casing design/placement
- When drilling in bedrock plan on a larger diameter conductor hole
- Have spare parts, pumps and air compressors on hand

Well Logging - Collection:

- Ensure baseline PNC logs are run after sufficient amount of time has passed from drilling the well
- Can run fewer "high-end/expensive" open hole logs in well-established areas

Well Logging – Analysis:

- Better data management from start of project – faster data integration

Well Coring – Data Analysis:

- Collect more whole core samples from injection zones
- Perform more SCAL tests to be used for model input parameters (e.g. mercury injection, geomechanical)

Injection Testing – Data Collection:

- High Priority, especially for "first" well in project/region
- Allow sufficient time for multi-zone (i.e. with packers) injection testing
- Equipment Planning – Thoroughly Vet Vendors (experience, novelty of what we planned)
- Procurement of high quality open hole packers for zone isolation
    - Should have multiple back-ups on-site
    - Should be field-serviceable
- Real-time down hole gauges for injection testing should be robust and field-serviceable
- Design well injection system to allow shutdown and shut-in (for reservoir characterization)
- Final key in characterization logging → core → reservoir test
- Thoroughly/accurately plan/schedule/budget, including contingencies (plan for failures, be flexible, nimble)
- Online/live data analysis during testing is strongly desired
- The flow meter logging surveys were very successful in identifying candidate in-flow zones for subsequent detailed hydrologic (packer) tests. In addition, collection of a temperature log 24 hours after the final dynamic logging survey provided valuable information to corroborate the results of the flow meter logging surveys. Strongly recommend incorporating flow meter logging surveys in all future well characterization programs in addition to standard coring and well logging programs.
- The discrete depth interval hydrologic (packer) tests were very successful in quantifying critical reservoir hydrologic parameters needed to identify candidate CO_2 injection zones and assess (model) CO_2 injectivity. Strongly recommend incorporating hydrologic (reservoir) testing in all future well characterization programs in addition to standard coring and well logging programs.

Copyright © 2012 American Electric Power Inc. All Rights Reserved

- It was prudent to allow time between the Phase I reservoir testing (flow meter logging) and Phase II reservoir testing (packer tests conducted within individual discrete-depth interval zones) to allow time to select target zones for detailed testing.
- Conducting both injection and withdrawal slug/DST tests is important.
- A service rig with a swabbing unit is essential for supporting the reservoir testing work. A drill rig is not required, and would not have the ability to conduct swabbing.
- Packer bypass (cross formational flow) was observed during some of the constant rate injection tests. Although injection pressures were well below fracture pressure, it is recommended to use low injection pressures in future injection testing.
- It is important to have a portable pump on site that can be used to inflate the packers and load the tubing string for injection slug/DST tests. This way, the pump truck only needs to be called to the site for the longer-duration constant rate injection tests. We used a rental pump for this purpose, and it turned out to be a cost saver.

Injection Testing – Data Analysis:

- Should allocate more staff time for analysis of injection testing data
- Software proved to very useful for analyzing reservoir pressure data for the purpose of characterizing reservoir properties.
- It is important to regularly analyze reservoir pressure data (injection/fall-off events) from the injection wells and monitoring wells. This was easy for the injection wells because bottom hole pressure data was obtained in real time; whereas, data from the monitoring wells was available only when gauges were pulled.
- Injectivity index is a useful parameter for tracking overall injection performance.
- Use of pressure memory gauges in the monitoring wells was appropriate and cost effective vs. real-time pressure monitoring systems for the short duration of this project. For longer-duration injection projects, real-time pressure monitoring systems may be more cost effective.

History Matching – Pressure Data:

- Develop workflow/process for interpreting and integrating results of CO_2 injection data
- Could have used lower pressure data sampling rate in monitoring wells and, to a degree, the injection wells
- More data accessibility in the future –continually self-updating data stream instead of weekly spreadsheet updates
- Good effort so far, need to do more, especially in correlation of pressure front and CO_2 front
- Pressure monitoring is very promising, but more modeling/analysis is needed [but geophysical methods may be at same state of development]

Geophysics:

- Need 3D data (could drive land acquisition), identifies faulting SE, guides risk
- Acknowledge limitations on purchased data (→can drive need for acquisition)
- Include detailed geomechanics
- Modeling effort (guides injection pressure) can minimize need for seismic
- Integrate seismic data is static model
- PNC – useful, low cost (allow time post drilling)
- Consider operation issues in planning repeats
- Fluid sampling shallow groundwater

Copyright © 2012 American Electric Power Inc. All Rights Reserved

- Soil Gas – likely needed, will be very labor intensive
- Groundwater monitoring – key to involve local plant expertise

Others:

- Use ongoing monitoring to guide future monitor needs (5yr→30yr) {adaptive strategy}
- Brine – target is to determine CO_2 breakthrough
- Satellite surface upheaval monitoring could be valuable

Copyright © 2012 American Electric Power Inc. All Rights Reserved

Appendix V:

2011 Operable Generating Units in the United States by State and Energy Source

Operable Generating Units in the United States by State and Energy Source, 2011

Note: Descriptions of field names and codes can be obtained from the record layout in the Form EIA-860 source data file at www.eia.gov/cneaf/electricity/page/eia860.html.

Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

State	County	Entity ID	Entity	Facility ID	Plant Name	Generator ID	Unit Code	Status	Nameplate Capacity (MW)	Net Summer Capacity (MW)	Net Winter Capacity (MW)
AL	Houston	195	Alabama Power Co	6001	Joseph M Farley	1		OP	888.2	874	874
AL	Houston	195	Alabama Power Co	6001	Joseph M Farley	2		OP	888.2	860	860
AZ	Maricopa	803	Arizona Public Service Co	6008	Palo Verde	1		OP	1403.1	1311	1311
AZ	Maricopa	803	Arizona Public Service Co	6008	Palo Verde	2		OP	1403.1	1314	1314
AZ	Maricopa	803	Arizona Public Service Co	6008	Palo Verde	3		OP	1403.1	1312	1312
AR	Pope	814	Entergy Arkansas Inc	6055	Arkansas Nuclear One	1		OP	902.5	834	858
AR	Pope	814	Entergy Arkansas Inc	6055	Arkansas Nuclear One	2		OP	942.5	989	1007
MD	Calvert	2876	Calvert Cliffs Nuclear PP LLC	6011	Calvert Cliffs Nuclear Power Plant	1		OP	918	855	872
MD	Calvert	2876	Calvert Cliffs Nuclear PP LLC	6011	Calvert Cliffs Nuclear Power Plant	2		OP	910.7	850	862
SC	Darlington	3046	Progress Energy Carolinas Inc	3251	H B Robinson	2		OP	768.6	724	758
NC	Brunswick	3046	Progress Energy Carolinas Inc	6014	Brunswick	1		OP	1001.6	938	975
NC	Brunswick	3046	Progress Energy Carolinas Inc	6014	Brunswick	2		OP	1001.6	932	953
NC	Wake	3046	Progress Energy Carolinas Inc	6015	Harris	1		OP	950.9	900	938
MI	Monroe	5109	Detroit Edison Co	1729	Fermi	2		OP	1217	1085	1120
CT	New London	5221	Dominion Nuclear Conn Inc	566	Millstone	2		OP	909.9	869.1	879.3
CT	New London	5221	Dominion Nuclear Conn Inc	566	Millstone	3		OP	1253	1233.4	1237.2
SC	Oconee	5416	Duke Energy Carolinas, LLC	3265	Oconee	1		OP	886.7	846	865
SC	Oconee	5416	Duke Energy Carolinas, LLC	3265	Oconee	2		OP	886.7	846	865
SC	Oconee	5416	Duke Energy Carolinas, LLC	3265	Oconee	3		OP	893.3	846	865
SC	York	5416	Duke Energy Carolinas, LLC	6036	Catawba	1		OP	1205.1	1129	1163
SC	York	5416	Duke Energy Carolinas, LLC	6036	Catawba	2		OP	1205.1	1129	1163
NC	Mecklenburg	5416	Duke Energy Carolinas, LLC	6038	McGuire	1		OP	1220.3	1100	1156
NC	Mecklenburg	5416	Duke Energy Carolinas, LLC	6038	McGuire	2		OP	1220.3	1100	1156
NY	Oswego	5943	Entergy Nuc Fitzpatrick LLC	6110	James A Fitzpatrick	1		OP	882	828.1	849.1
VT	Windham	5956	Entergy Nuclear Vermont Yankee	3751	Vermont Yankee	1		OP	563.4	620.3	628
NY	Westchester	6027	Entergy Nuclear Indian Point 2	2497	Indian Point 2	2		OP	1299	1006.1	1028.6
NY	West Chester	6028	Entergy Nuclear Indian Point 3	8907	Indian Point 3	3		OP	1012	1030.9	1046.8
FL	Miami-Dade	6452	Florida Power & Light Co	621	Turkey Point	3		OP	760	693	717
FL	Miami-Dade	6452	Florida Power & Light Co	621	Turkey Point	4		OP	760	693	717
FL	St Lucie	6452	Florida Power & Light Co	6045	St Lucie	1		OP	850	839	853
FL	St Lucie	6452	Florida Power & Light Co	6045	St Lucie	2		OP	850	839	853
FL	Citrus	6455	Progress Energy Florida Inc	628	Crystal River	3		OS	890.4	860	877
NH	Rockingham	6854	NextEra Energy Seabrook LLC	6115	Seabrook	1		OP	1242	1246.2	1246.7
GA	Burke	7140	Georgia Power Co	649	Vogtle	1		OP	1160	1150	1150
GA	Burke	7140	Georgia Power Co	649	Vogtle	2		OP	1160	1152	1152
GA	Appling	7140	Georgia Power Co	6051	Edwin I Hatch	1		OP	867.1	876	876
GA	Appling	7140	Georgia Power Co	6051	Edwin I Hatch	2		OP	864.7	883	883
MI	Berrien	9324	Indiana Michigan Power Co	6000	Donald C Cook	1		OP	1152	1009	1084
MI	Berrien	9324	Indiana Michigan Power Co	6000	Donald C Cook	2		OP	1133.3	1060	1107
LA	St Charles	11241	Entergy Louisiana Inc	4270	Waterford 3	3		OP	1199.8	1159	1178
MS	Claiborne	12485	System Energy Resources, Inc	6072	Grand Gulf	1		OP	1372.5	1190	1201
NE	Nemaha	13337	Nebraska Public Power District	6036	Cooper	1		OP	801	765.9	765.9
NY	Oswego	13606	Nine Mile Point Nuclear Sta LLC	2589	Nine Mile Point Nuclear Station	1		OP	641.8	630	630
NY	Oswego	13606	Nine Mile Point Nuclear Sta LLC	2589	Nine Mile Point Nuclear Station	2		OP	1259.3	1143	1152
MN	Wright	13781	Northern States Power Co - Minnesota	1922	Monticello	1		OP	631.2	554	581
MN	Goodhue	13781	Northern States Power Co - Minnesota	1925	Prairie Island	1		OP	593.1	521	546
MN	Goodhue	13781	Northern States Power Co - Minnesota	1925	Prairie Island	2		OP	593.1	519	546
NE	Washington	14127	Omaha Public Power District	2289	Fort Calhoun	1		OA	502	478.6	478.6
PA	Luzerne	14266	PPL Susquehanna LLC	6103	PPL Susquehanna	1		OP	1298	1260	1300
PA	Luzerne	14266	PPL Susquehanna LLC	6103	PPL Susquehanna	2		OP	1298	1260	1300
CA	San Luis Obispo	14328	Pacific Gas & Electric Co	6099	Diablo Canyon	1		OP	1169	1122	1122
CA	San Luis Obispo	14328	Pacific Gas & Electric Co	6099	Diablo Canyon	2		OP	1164	1118	1118
NJ	Salem	15478	PSEG Nuclear LLC	2410	PSEG Salem Generating Station	1		OP	1170	1165.9	1187.9
NJ	Salem	15478	PSEG Nuclear LLC	2410	PSEG Salem Generating Station	2		OP	1170	1159.9	1185.8
NJ	Salem	15478	PSEG Nuclear LLC	6118	PSEG Hope Creek Generating Station	1		OP	1170	1172.9	1251.8
SC	Fairfield	17539	South Carolina Electric&Gas Co	6127	V C Summer	1		OP	1029.8	966	980
CA	San Diego	17609	Southern California Edison Co	360	San Onofre Nuclear Generating Station	2		OP	1127	1070	1070
CA	San Diego	17609	Southern California Edison Co	360	San Onofre Nuclear Generating Station	3		OP	1127	1080	1080
AL	Limestone	18642	Tennessee Valley Authority	46	Browns Ferry	1		OP	1152	1100.8	1131.7
AL	Limestone	18642	Tennessee Valley Authority	46	Browns Ferry	2		OP	1152	1103.7	1135.2
AL	Limestone	18642	Tennessee Valley Authority	46	Browns Ferry	3		OP	1190	1104.9	1134.2
TN	Hamilton	18642	Tennessee Valley Authority	6152	Sequoyah	1		OP	1220.6	1152	1177.4
TN	Hamilton	18642	Tennessee Valley Authority	6152	Sequoyah	2		OP	1220.6	1125.7	1155.1
TN	Rhea	18642	Tennessee Valley Authority	7722	Watts Bar Nuclear Plant	1		OP	1289.9	1123	1179
MO	Callaway	19436	Union Electric Co - (MO)	6153	Callaway	1		OP	1236.8	1190	1240
VA	Surry	19876	Virginia Electric & Power Co	3806	Surry	1		OP	847.5	838	875
VA	Surry	19876	Virginia Electric & Power Co	3806	Surry	2		OP	847.5	838	875
VA	Louisa	19876	Virginia Electric & Power Co	6168	North Anna	1		OP	979.7	920	929
VA	Louisa	19876	Virginia Electric & Power Co	6168	North Anna	2		OP	979.7	943	975
WA	Benton	20180	Energy Northwest	371	Columbia Generating Station	2		OP	1200	1097	1138
KS	Coffey	20893	Wolf Creek Nuclear Optg Corp	210	Wolf Creek Generating Station	1		OP	1267.7	1175	1205
TX	Matagorda	21535	STP Nuclear Operating Co	6251	South Texas Project	1		OP	1354.3	1280	1280
TX	Matagorda	21535	STP Nuclear Operating Co	6251	South Texas Project	2		OP	1354.3	1280	1280
MA	Plymouth	22928	Entergy Nuclear Generation Co	1590	Pilgrim Nuclear Power Station	1		OP	670	684.7	684.7
NY	Wayne	50100	R.E. Ginna Nuclear Power Plant, LLC	6122	R E Ginna Nuclear Power Plant	1		OP	614	580.9	581.8
OH	Lake	50161	FirstEnergy Nuclear Operating Company	6020	Perry	1		OP	1311.8	1240	1268
PA	Beaver	50161	FirstEnergy Nuclear Operating Company	6040	Beaver Valley	1		OP	923.4	892	911
PA	Beaver	50161	FirstEnergy Nuclear Operating Company	6040	Beaver Valley	2		OP	923.4	885	904
OH	Ottawa	50161	FirstEnergy Nuclear Operating Company	6149	Davis Besse	1		OP	925.2	894	908
WI	Kewaunee	54718	Dominion Energy Kewaunee Inc.	6024	Kewaunee	1		OP	560.1	566	574
IA	Linn	55289	NextEra Energy Duane Arnold LLC	1060	Duane Arnold Energy Center	1		OP	679.5	601.4	622.1
WI	Manitowoc	55906	NextEra Energy Point Beach LLC	4046	Point Beach Nuclear Plant	1		OP	643	591	594
WI	Manitowoc	55906	NextEra Energy Point Beach LLC	4046	Point Beach Nuclear Plant	2		OP	643	593	594
LA	West Feliciana	55938	Entergy Gulf States - LA LLC	6462	River Bend	1		OP	1035.9	974	979
IL	De Witt	55951	Exelon Nuclear	204	Clinton Power Station	1		OP	1136.3	1065	1078
IL	Grundy	55951	Exelon Nuclear	869	Dresden Generating Station	2		OP	1009.3	867	867
IL	Grundy	55951	Exelon Nuclear	869	Dresden Generating Station	3		OP	1009.3	867	867
IL	Rock Island	55951	Exelon Nuclear	880	Quad Cities Generating Station	1		OP	1009.3	908	908
IL	Rock Island	55951	Exelon Nuclear	880	Quad Cities Generating Station	2		OP	1009.3	911	911
NJ	Ocean	55951	Exelon Nuclear	2388	Oyster Creek	1		OP	550	614	637
PA	York	55951	Exelon Nuclear	3166	Peach Bottom	2		OP	1159.7	1122	1148
PA	York	55951	Exelon Nuclear	3166	Peach Bottom	3		OP	1159.7	1122	1148
IL	Will	55951	Exelon Nuclear	6022	Braidwood Generation Station	1		OP	1224.9	1178	1208
IL	Will	55951	Exelon Nuclear	6022	Braidwood Generation Station	2		OP	1224.9	1162	1176
IL	Ogle	55951	Exelon Nuclear	6023	Byron Generating Station	1		OP	1224.9	1164	1188
IL	Ogle	55951	Exelon Nuclear	6023	Byron Generating Station	2		OP	1224.9	1138	1168
IL	La Salle	55951	Exelon Nuclear	6026	LaSalle Generating Station	1		OP	1170	1118	1133
IL	La Salle	55951	Exelon Nuclear	6026	LaSalle Generating Station	2		OP	1170	1120	1141
PA	Montgomery	55951	Exelon Nuclear	8105	Limerick	1		OP	1138.5	1146	1191
PA	Montgomery	55951	Exelon Nuclear	8105	Limerick	2		OP	1138.5	1150	1195
PA	Dauphin	55951	Exelon Nuclear	8011	Three Mile Island	1		OP	976.6	806	829
TX	Somervell	55983	Luminant Generation Company LLC	6145	Comanche Peak	1		OP	1215	1205	1235
TX	Somervell	55983	Luminant Generation Company LLC	6145	Comanche Peak	2		OP	1215	1196	1225
MI	Van Buren	56192	Entergy Nuclear Palisades LLC	1715	Palisades	1		OP	811.8	803.4	819.8
								Total:	107001.2	101418.8	
									Difference:	5582.4	

Plant Name	Generator ID	Primary Purpose	Prime Mover	Primary Energy Source	Secondary Energy Source
Joseph M Farley	1	22	ST	NUC	
Joseph M Farley	2	22	ST	NUC	
Palo Verde	1	22	ST	NUC	
Palo Verde	2	22	ST	NUC	
Palo Verde	3	22	ST	NUC	
Arkansas Nuclear One	1	22	ST	NUC	
Arkansas Nuclear One	2	22	ST	NUC	
Calvert Cliffs Nuclear Power Plant	1	22	ST	NUC	
Calvert Cliffs Nuclear Power Plant	2	22	ST	NUC	
H B Robinson	2	22	ST	NUC	
Brunswick	1	22	ST	NUC	
Brunswick	2	22	ST	NUC	
Harris	1	22	ST	NUC	
Fermi	2	22	ST	NUC	
Millstone	2	22	ST	NUC	
Millstone	3	22	ST	NUC	
Oconee	1	22	ST	NUC	
Oconee	2	22	ST	NUC	
Oconee	3	22	ST	NUC	
Catawba	1	22	ST	NUC	
Catawba	2	22	ST	NUC	
McGuire	1	22	ST	NUC	
McGuire	2	22	ST	NUC	
James A Fitzpatrick	1	22	ST	NUC	
Vermont Yankee	1	22	ST	NUC	
Indian Point 2	2	22	ST	NUC	
Indian Point 3	3	22	ST	NUC	
Turkey Point	5	22	ST	NUC	
Turkey Point	4	22	ST	NUC	
St Lucie	1	22	ST	NUC	
St Lucie	2	22	ST	NUC	
Crystal River	3	22	ST	NUC	
Seabrook	1	22	ST	NUC	
Vogtle	1	22	ST	NUC	
Vogtle	2	22	ST	NUC	
Edwin I Hatch	1	22	ST	NUC	
Edwin I Hatch	2	22	ST	NUC	
Donald C Cook	1	22	ST	NUC	
Donald C Cook	2	22	ST	NUC	
Waterford 3	3	22	ST	NUC	
Grand Gulf	1	22	ST	NUC	
Cooper	1	22	ST	NUC	
Nine Mile Point Nuclear Station	1	22	ST	NUC	
Nine Mile Point Nuclear Station	2	22	ST	NUC	
Monticello	1	22	ST	NUC	
Prairie Island	1	22	ST	NUC	
Prairie Island	2	22	ST	NUC	
Fort Calhoun	1	22	ST	NUC	
PPL Susquehanna	1	22	ST	NUC	
PPL Susquehanna	2	22	ST	NUC	
Diablo Canyon	1	22	ST	NUC	
Diablo Canyon	2	22	ST	NUC	
PSEG Salem Generating Station	1	22	ST	NUC	
PSEG Salem Generating Station	2	22	ST	NUC	
PSEG Hope Creek Generating Station	1	22	ST	NUC	
V C Summer	1	22	ST	NUC	
San Onofre Nuclear Generating Station	2	22	ST	NUC	
San Onofre Nuclear Generating Station	3	22	ST	NUC	
Browns Ferry	1	22	ST	NUC	
Browns Ferry	2	22	ST	NUC	
Browns Ferry	3	22	ST	NUC	
Sequoyah	1	22	ST	NUC	
Sequoyah	2	22	ST	NUC	
Watts Bar Nuclear Plant	1	22	ST	NUC	
Callaway	1	22	ST	NUC	
Surry	1	22	ST	NUC	
Surry	2	22	ST	NUC	
North Anna	1	22	ST	NUC	
North Anna	2	22	ST	NUC	
Columbia Generating Station	2	22	ST	NUC	
Wolf Creek Generating Station	1	22	ST	NUC	
South Texas Project	1	22	ST	NUC	
South Texas Project	2	22	ST	NUC	
Pilgrim Nuclear Power Station	1	22	ST	NUC	
R E Ginna Nuclear Power Plant	1	22	ST	NUC	
Perry	1	22	ST	NUC	
Beaver Valley	1	22	ST	NUC	
Beaver Valley	2	22	ST	NUC	
Davis Besse	1	22	ST	NUC	
Kewaunee	1	22	ST	NUC	
Duane Arnold Energy Center	1	22	ST	NUC	
Point Beach Nuclear Plant	1	22	ST	NUC	
Point Beach Nuclear Plant	2	22	ST	NUC	
River Bend	1	22	ST	NUC	
Clinton Power Station	1	22	ST	NUC	
Dresden Generating Station	2	22	ST	NUC	
Dresden Generating Station	3	22	ST	NUC	
Quad Cities Generating Station	1	22	ST	NUC	
Quad Cities Generating Station	2	22	ST	NUC	
Oyster Creek	1	22	ST	NUC	
Peach Bottom	2	22	ST	NUC	
Peach Bottom	3	22	ST	NUC	
Braidwood Generation Station	1	22	ST	NUC	
Braidwood Generation Station	2	22	ST	NUC	
Byron Generating Station	1	22	ST	NUC	
Byron Generating Station	2	22	ST	NUC	
LaSalle Generating Station	1	22	ST	NUC	
LaSalle Generating Station	2	22	ST	NUC	
Limerick	1	22	ST	NUC	
Limerick	2	22	ST	NUC	
Three Mile Island	1	22	ST	NUC	
Comanche Peak	1	22	ST	NUC	
Comanche Peak	2	22	ST	NUC	
Palisades	1	22	ST	NUC	

Appendix W:

Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Attainment Demonstration

Revisions to the State Implementation Plan (SIP)
for the Control of Ozone Air Pollution

DALLAS-FORT WORTH EIGHT-HOUR OZONE NONATTAINMENT AREA ATTAINMENT DEMONSTRATION

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
P.O. BOX 13087
AUSTIN, TEXAS 78711-3087

Adoption
May 23, 2007

PROJECT NO. 2006-013-SIP-NR

EXECUTIVE SUMMARY

This state implementation plan addresses ozone formation in the Dallas-Fort Worth (DFW) area, the precursor emissions of nitrogen oxides (NO_X)and volatile organic compounds (VOC), what control strategies are to be implemented, how much emission reduction are associated with each strategy, when these reductions will occur. Based on photochemical modeling and an evaluation of corroborative evidence, ozone measurements in DFW will be compliant with the national ambient air quality standard (NAAQS) by June 15, 2010.

Following promulgation of the 1990 Federal Clean Air Act (FCAA) Amendments, The United States Environmental Protection Agency (EPA) classified the DFW area as moderate nonattainment for the one-hour ozone standard. Since then, the Texas Commission on Environmental Quality (TCEQ) and DFW area local governments have taken steps to improve DFW air quality through the implementation of numerous control measures targeting attainment of the one-hour ozone NAAQS. These control strategies have resulted in significant improvements to DFW's air quality as demonstrated by the decrease in the DFW area's one-hour ozone design value over the past 15 years. The one-hour design value has decreased about 11.4 percent since 1991, and the eight-hour ozone design value has decreased by approximately 8.6 percent. On June 15, 2005, the one-hour ozone NAAQS was revoked, leaving only an eight-hour ozone standard, effective June 15, 2004. In 2006, the one-hour ozone design value was measured at 124 ppb, which demonstrates attainment of the former one-hour ozone standard. The design value for eight-hour ozone was 96 ppb in 2006. The DFW area is required to attain the new eight-hour ozone standard by June 15, 2010. This SIP revision demonstrates attainment of the eight-hour ozone NAAQS in the DFW area.

Despite the significant decreases in one-hour and eight-hour ozone design values and in NO_X and VOC emissions in the DFW area, the increased stringency of the eight-hour ozone standard requires further reductions to bring the area into attainment of the eight-hour ozone standard. Rapid population growth and economic development in the DFW nonattainment area present numerous and complex challenges to reducing NO_X and VOC emissions. However, despite the increasing population in the DFW nine-county area and along with other factors, such as increased vehicle miles traveled, the DFW area continues to experience decreasing trends in ambient ozone and its precursor emissions, NO_X and VOC.

Analysis of VOC and NO_X sensitivity to the ozone formation indicate that the optimum path to attainment is through NO_X reductions. Accordingly, this SIP submittal contains NO_X control strategies, which are summarized below in Table ExSum-1: *Summary of Control Strategy NO_X Reduction Estimates for the DFW Eight-Hour Ozone Attainment Demonstration* and estimated NO_X reductions in Table ExSum-2: *DFW Baseline, Future Base, and Control Case NO_X Emissions.*

Table ExSum-1: Summary of Control Strategy NO_X Reduction Estimates for the DFW Eight-Hour Ozone Attainment Demonstration

TCEQ Rules	Estimated NO_X Reductions by June 15, 2010
	tpd
DFW Industrial, Commercial, and Institutional Sources Rule	8.88 [1]
DFW Electric Generating Facilities (EGF)	0.4
DFW Minor Sources	2.9
Cement Kilns	9.69 [2]
East Texas Combustion Sources	22.4
Total	44.27 [3]

[1] The final control strategy modeled assumed 9.0 tpd NO_X reduction from DFW industrial, commercial, and institutional sources.
[2] The final control strategy modeled assumed 10.4 tpd NO_X reduction from the cement kiln rule.
[3] Collectively, the final control strategy modeled assumed a 45.1 tpd NO_X reduction from the Chapter 117 rules for major and minor sources (including EGFs, cement kilns and East Texas combustion sources). These rules, as adopted, are expected to reduce NO_X by 44.27 tpd. The 0.83 tpd additional NO_X from rule changes predicts modeled ozone to increase approximately 0.04 ppb at the monitor showing the greatest change, Fort Worth C13. Increases at other monitors will be less and this change does not affect the number of monitors predicted to be at or above 85 ppb.

DFW Local Initiatives	Estimated NO_X Reductions in 2009
	tpd
Voluntary Mobile Emissions Reduction Program (VMEP) in nine counties	2.63
Transportation Control Measures (TCMs) in nine counties	1.53
Total	4.16

Federal Measures	Estimated NO_X Reductions in 2009
	tpd
On-Road	217.52
Non-Road	21.49

Table ExSum-2: DFW Baseline, Future Base, and Control Case NO_X Emissions

Weekday (August 17, 1999) Emissions Inventory	1999 Baseline Emissions	2009.a2 Future Year Baseline Inventory	2009.a2 Future Year Combo 10 Inventory
	tpd	*tpd*	*tpd*
Area sources	34	44	41
Non-road sources	148	107	105
Point Sources	134	59	40
On-road mobile sources	437	193	187
Biogenic sources	52	52	52
Total NOx Emissions	**805**	**455**	**425**

This plan demonstrates attainment using photochemical modeling that includes the above control strategies. The demonstration also relies on weight of evidence (WoE) (see Chapter 3) and additional control measures not explicitly accounted for in the photochemical modeling.

This SIP revision includes 1999 base and baseline case modeling and 2009 future case modeling with and without the control strategies identified in Table ExSum-1: *Summary of Control Strategy NO_X Reduction Estimates for the DFW Eight-Hour Ozone Attainment Demonstration.* Only two monitors remain above 85 ppb once the control package has been applied. Because photochemical modeling is an evaluation tool and not an absolute prediction of future ozone concentrations, additional data must be considered to draw conclusions about the validity of the final predicted design value and whether the attainment demonstration satisfies the requirements of the FCAA.

Table ExSum-3: Future Design Value Calculations with Controls from Table ExSum-1

	2009 Baseline			2009 Combo #10			
Site Name	Baseline DV	Average RRF	Future DV	Baseline DV	Average RRF	Future DV	
	ppb		*ppb*	*ppb*		*ppb*	truncated
Frisco C31	100.3	0.890	89.3	100.3	0.884	88.7	88
Dallas Hinton C60	92.0	0.936	86.1	92.0	0.930	85.6	**85**
Dallas North C63	93.0	0.917	85.3	93.0	0.912	**84.8**	**84**
Dallas Exec C402	88.0	0.905	**79.7**	88.0	0.896	**78.8**	**78**
Denton C56	101.5	0.878	89.1	101.5	0.873	88.6	88
Midlothian C94	92.5	0.918	**84.9**	92.5	0.907	**83.9**	**83**
Arlington C57	90.5	0.909	**82.2**	90.5	0.894	**80.9**	**80**
FtW NW C13	98.3	0.884	86.9	98.3	0.871	85.6	**85**
FtW Keller C17	96.3	0.887	85.4	96.3	0.881	**84.8**	**84**
Average	94.7	--	85.4	--	--	**84.6**	**83.9**

This SIP provides ozone reduction trends analyses and supplementary data to demonstrate that the DFW nine-county nonattainment area will attain the 0.08 ppm eight-hour ozone standard. The corroborative analysis in Chapter 3 and Additional Measures in Chapter 4 Section 4.2.6 not included in the model support a conclusion that this DFW SIP demonstrates attainment of the eight-hour ozone NAAQS. These additional measures include the EPA's SmartWay and Blue SkyWays Programs, energy efficiency measures, Clean School Bus Program, stationary diesel and dual-fuel engine control measures, additional Texas Emissions Reduction Plan (TERP) and Low Income Vehicle Repair Assistance, Retrofit, and Accelerated Vehicle Retirement Program (LIRAP) commitments, and fleet turnover from 2009 to June 15, 2010.

Anthropogenic NO_X and VOC emissions fall into four categories: point source, on-road mobile sources, non-road mobile sources, and area sources, with the largest source of NO_X emissions in the DFW area being from on-road mobile sources. Over the past 14 years, point source NO_X emissions decreased by 44 percent. This decreasing trend in reported emissions is corroborated by the decrease in measured ambient NO_X concentrations over the past 15 years. The VOC emissions in the DFW area come primarily from on-road mobile sources and area sources.

Reported VOC emissions decreased by about 30 percent in the past 14 years, with ambient VOC concentrations also decreasing over the last nine years.

On-road and non-road mobile sources are the largest NO_X contributors in the DFW area. The TCEQ's 2009 future case emissions inventory shows that on-road and non-road mobile sources contribute 74 percent of the NO_X emissions. The trends in total NO_X emissions are dependent upon trends in the NO_X emissions from on-road mobile sources, a source category for which the TCEQ does not have direct legal authority to set emission standards. Even though DFW area population and vehicle miles traveled have increased, NO_X emissions from on-road mobile sources, as well as the total NO_X emissions from all source categories have decreased since 1999. Decreases in the on-road source category are in part attributed to fleet turnover and the implementation of programs such as TERP, the Vehicle Inspection and Maintenance (I/M) Program in the DFW area, and Texas Low Emission Diesel (TxLED) in East and Central Texas.

This revision includes details regarding the control strategies identified in Table ExSum-1: *Summary of Control Strategies NO_X Reduction Estimates for the DFW Attainment Demonstration*, data showing progress that the DFW area has made toward attainment, a reasonably available control measures (RACM) analysis, a reasonably available control technology (RACT) analysis, and a motor vehicle emissions budget (MVEB). For the MVEB, see Table ExSum-4: 2009 *Attainment Demonstration Motor Vehicle Emissions Budget for the Nine-County DFW Area.*

Table ExSum-4: 2009 Attainment Demonstration Motor Vehicle Emissions Budget for the Nine-County DFW Area

Nine-County DFW Area	Total Emissions	
	NO_x	VOC
	tpd	*tpd*
DFW motor vehicle emissions budget	186.81	99.09

SECTION V: LEGAL AUTHORITY

A. General

The TCEQ has the legal authority to implement, maintain, and enforce the national ambient air quality standards.

The first air pollution control act, known as the Clean Air Act of Texas, was passed by the Texas Legislature in 1965. In 1967, the Clean Air Act of Texas was superseded by a more comprehensive statute, the Texas Clean Air Act (TCAA), found in Article 4477-5, Vernon's Texas Civil Statutes. The Legislature amended the TCAA in 1969, 1971, 1973, 1979, 1985, 1987, 1989, 1991, 1993, 1995, 1997, 1999, 2001, 2003, and 2005. In 1989, the TCAA was codified as Chapter 382 of the Texas Health & Safety Code.

Originally, the TCAA stated that the Texas Air Control Board (TACB) is the state air pollution control agency and is principal authority in the state on matters relating to the quality of air resources. In 1991, the Legislature abolished the TACB effective September 1, 1993, and its powers, duties, responsibilities and functions were transferred to the Texas Natural Resource Conservation Commission (TNRCC). With the creation of the TNRCC, the authority over air quality is found in both the Texas Water Code and the TCAA. Specifically, the authority of the TNRCC is found in Chapters 5 and 7. Chapter 5, Subchapters A - F, H – J, and L, include the general provisions, organization and general powers and duties of the TNRCC, and the responsibilities and authority of the Executive Director. This Chapter also authorizes the TNRCC to implement action when emergency conditions arise, and to conduct hearings. Chapter 7 gives the TNRCC enforcement authority. In 2001, the 77th Texas Legislature continued the existence of the TNRCC until September 1, 2013, and changed the name of the TNRCC to the Texas Commission on Environmental Quality (TCEQ).

The TCAA specifically authorizes the TCEQ to establish the level of quality to be maintained in the state's air and to control the quality of the state's air by preparing and developing a general, comprehensive plan. The TCAA, Subchapters A - D, also authorize the TCEQ to collect information to enable the commission to develop an inventory of emissions; to conduct research and investigations; to enter property and examine records; to prescribe monitoring requirements; to institute enforcement proceedings; to enter into contracts and execute instruments; to formulate rules; to issue orders taking into consideration factors bearing upon health, welfare, social and economic factors, and practicability and reasonableness; to conduct hearings; to establish air quality control regions; to encourage cooperation with citizens' groups and other agencies and political subdivisions of the state as well as with industries and the Federal Government; and to establish and operate a system of permits for construction or modification of facilities.

Local government authority is found in Subchapter E of the TCAA. Local governments have the same power as the TCEQ to enter property and make inspections. They also may make recommendations to the Commission concerning any action of the TCEQ that affects their territorial jurisdiction, may bring enforcement actions, and may execute cooperative agreements with the TCEQ or other local governments. In addition, a city or town may enact and enforce ordinances for the control and abatement of air pollution not inconsistent with the provisions of the TCAA and the rules or orders of the Commission.

Subchapters F, G, and H of the TCAA authorize the TCEQ to establish low emission vehicle requirements for mass transit authorities, local government fleets, and private fleets; create a

mobile emissions reduction credit program; establish vehicle inspection and maintenance programs in certain areas of the state, consistent with the requirements of the federal Clean Air Act; establish gasoline volatility and low emission diesel standards; and fund and authorize participating counties to implement low-income vehicle repair assistance, retrofit, and accelerated vehicle retirement programs.

B. Applicable Law

The following statutes and rules provide necessary authority to adopt and implement the SIP. The rules listed below have previously been submitted as part of the SIP.

Statutes

TEXAS HEALTH & SAFETY CODE, Chapter 382	September 1, 2005
TEXAS WATER CODE	September 1, 2005

All sections of each subchapter are included, unless otherwise noted.

Chapter 5: Texas Natural Resource Conservation Commission
Subchapter A: General Provisions
Subchapter B: Organization of the Texas Natural Resource Conservation Commission
Subchapter C: Texas Natural Resource Conservation Commission
Subchapter D: General Powers and Duties of the Commission
Subchapter E: Administrative Provisions for Commission
Subchapter F: Executive Director (except §§ 5.225, 5.226, 5.227, 5.2275, 5.232, and 5.236)
Subchapter H: Delegation of Hearings
Subchapter I: Judicial Review
Subchapter J: Consolidated Permit Processing
Subchapter L: Emergency and Temporary Orders (§§ 5.514, 5.5145 and 5.515 only)

Chapter 7: Enforcement
Subchapter A: General Provisions (§§ 7.001, 7.002, 7.0025, 7.004, 7.005 only)
Subchapter B: Corrective Action and Injunctive Relief (§ 7.032 only)
Subchapter C: Administrative Penalties
Subchapter E Criminal Offenses and Penalties: §§ 7.177, 7.179-7.181

Rules

All of the following rules are found in Title 30, Texas Administrative Code, as of the following effective dates:

Chapter 7, Memoranda of Understanding, §§ 7.110 and 7.119	May 2, 2002
Chapter 35, Subchapters A-C, K: Emergency and Temporary Orders and Permits; Temporary Suspension or Amendment of Permit Conditions	December 10, 1998
Chapter 39, Public Notice, §§ 39.201; 39.401; 39.403(a) and (b)(8)-(10); 39.405(f)(1) and (g);39.409; 39.411 (a), (b)(1)-(6) and (8)-(10) and (c)(1)-(6) and (d); 39.413(9), (11), (12) and (14);	August 15, 2002

39.418(a) and (b)(3) and (4); 39.419(a), (b),(d) and (e); 39.420(a), (b) and (c)(3) and (4); 39.423 (a) and (b); 39.601; 39.602; 39.603; 39.604; and 39.605	
Chapter 55, Request for Contested Case Hearings; Public Comment, §§ 55.1; 55.21(a) - (d), (e)(2), (3) and (12), (f) and (g); 55.101(a), (b), (c)(6) - (8); 55.103; 55.150; 55.152(a)(1), (2) and (6) and (b); 55.154; 55.156; 55.200; 55.201(a) - (h); 55.203; 55.205; 55.206; 55.209 and 55.211	August 29, 2002
Chapter 101: General Air Quality Rules	June 23, 2005
Chapter 106: Permits by Rule, Subchapters A	June 30, 2004
Chapter 111: Control of Air Pollution from Visible Emissions and Particulate Matter	November 18, 2004
Chapter 112: Control of Air Pollution from Sulfur Compounds	July 16, 1997
Chapter 113, Standards of Performance for Hazardous Air Pollutants and for Designated Facilities and Pollutants	June 15, 2005
Chapter 114: Control of Air Pollution from Motor Vehicles	May 19, 2005
Chapter 115: Control of Air Pollution from Volatile Organic Compounds	May 5, 2005
Chapter 116: Permits for New Construction or Modification	June 15, 2005
Chapter 117: Control of Air Pollution from Nitrogen Compounds	May 19, 2005
Chapter 118: Control of Air Pollution Episodes	March 5, 2000
Chapter 122, § 122.122: Potential to Emit	December 11, 2002

SECTION VI. CONTROL STRATEGY

A. Introduction (No Change)

B. Ozone (Revised)

1. *Dallas-Fort Worth* **(Revised May 23, 2007)**
   Chapter 1: Background and Introduction
   Chapter 2: Photochemical Modeling
   Chapter 3: Corroborative Analysis
   Chapter 4: Control Strategies and Required Elements
2. *Houston-Galveston-Brazoria* **(Revised May 23, 2007)**
3. *Beaumont-Port Arthur* (No change)
4. *El Paso* (No change)
5. *Regional Strategies* (No change)
6. *Northeast Texas* (No change)
7. *Austin Area* (No change)
8. *San Antonio Area* (No change)

C. Particulate Matter (No change)

D. Carbon Monoxide (No change)

E. Lead (No change)

F. Oxides of Nitrogen (No change)

G. Sulfur Dioxide (No change)

H. Conformity with the National Ambient Air Quality Standards (No change)

I. Site Specific (No change)

J. Mobile Sources Strategies (No change)

K. Clean Air Interstate Rule (No change)

LIST OF ACRONYMS

ACT -- Alternative Control Techniques
AF -- Air-to-Fuel
APU -- Auxiliary Power Units
ARPDB -- Acid Rain Program Data Base
ATCM – Airborne Toxic Control Measure
auto-GC -- Automated Gas Chromatograph
BACT -- Best Available Control Technology
BCCA-AG -- Business Coalition for Clean Air-Appeal Group
BMP -- Best Management Practices
BPA -- Beaumont-Port Arthur
Btu/hr -- British Thermal Units per Hour
Btu/scf -- British Thermal Units per Square Cubic Feet
CAE -- Cetane Additive Enhanced Diesel Fuel
CAIR -- Clean Air Interstate Rule
CAMx -- Comprehensive Air Model with Extensions
CARB -- California Air Resources Board
CBD -- Houston's Central Business District
CFR -- Code of Federal Regulations
CMAQ -- Congestion Mitigation and Air Quality
CO -- Carbon Monoxide
CTG -- Control Technique Guidelines
DECS -- Diesel Emission Control Strategy
DERC -- Discrete Emission Reduction Credits
DFW -- Dallas-Fort Worth
DPM -- Diesel Particulate Matter
DRRP -- Diesel Risk Reduction Program
DV -- Design Value
DVc -- Current Design Value
DVf -- Future Design Value
EAC -- Early Action Compact
EDMS -- Emissions and Dispersion Modeling System
E-GRID-2007 -- Emissions and Generation Resource Integrated Database
EE/RE -- Energy Efficiency/Renewable Energy
EGAS -- Economic Growth Analysis System
EGF -- Electric Generating Facilities
EGU -- Electric Generating Units
EI -- Emissions Inventory
EPA -- United States Environmental Protection Agency
EPS3 -- Emissions Processing System, version 3
ERC -- Emission Reduction Credits
ERCOT -- Electric Reliability Council of Texas
ESAD -- Emission Specification for Attainment Demonstration
ESL -- Energy Systems Laboratory, the Texas A&M University System
F -- Fahrenheit
FAA -- Federal Aviation Administration
FCAA -- Federal Clean Air Act
FCV -- Fuel Cell Vehicle
FGR -- Flue Gas Recirculation
FHWA -- Federal Highway Administration
FR -- Federal Register
FT -- Fischer-Tropsch Diesel Fuel

GIS -- Geographic Information System
GloBEIS -- Global Biosphere Emissions and Interactions System
gpm -- Gallons per Minute
GTM -- Gross Ton Mile
HAP -- Hazardous Air Pollutant
HARC -- Houston Advanced Research Center
HDT -- Heavy-Duty Truck
HECT -- Highly-Reactive Volatile Organic Compound Emissions Cap and Trade Program
HGB -- Houston-Galveston-Brazoria
H-GAC -- Houston-Galveston Area Council
HOV -- High Occupancy Vehicle
hp -- Horsepower
HPMS -- Highway Performance Monitoring System
HRVOC -- Highly-Reactive Volatile Organic Compound
HSC -- Houston Ship Channel
IC -- Internal Combustion
ICI -- Industrial, Commercial, and Institutional
IECC -- International Energy Conservation Code
I/M -- Inspection and Maintenance
km -- Kilometer
K_Vs -- Vertical Exchange Coefficient
LAER -- Lowest Achievable Emission Rate
lb/MMBtu -- Pound per Million British Thermal Units
LDAR -- Leak Detection and Repair
LDIR -- Light Detection and Ranging
LDEQ -- Louisiana Department of Environmental Quality
LDGV -- Light-Duty Gasoline Vehicle
LDT -- Light-Duty Truck
LDV -- Light-Duty Vehicle
LED -- Low Emission Diesel
LEV -- Low Emission Vehicle
LEV II -- California's Low Emission Vehicle II Program
LIRAP -- Low Income Repair and Assistance Program
LNB -- Low Nitrogen Oxides (NO_X) Burners
LNC -- Low Nitrogen Oxides (NO_X) Combustors
LNG -- Liquefied Natural Gas
LTO -- Landing and Take-Off
MACT -- Maximum Achievable Control Technology
Mcf -- Thousand Cubic Feet
MCR -- Mid-Course Review
MDPV -- Medium-Duty Passenger Vehicle
MECT -- Mass Emissions Cap and Trade Program
MM5 -- Fifth Generation Meteorological Model
MMBtu/hr -- Million British Thermal Units per Hour
MMcf -- Million Cubic Feet
MMS -- Minerals Management Service
MOA -- Memorandum of Agreement
MON -- Miscellaneous Organic National Emission Standards for Hazardous Air Pollutants (NESHAP)
mph -- miles per hour
MVEB -- Motor Vehicle Emissions Budget
MW -- Megawatts
MY -- Model Year
NAAQS -- National Ambient Air Quality Standard

NEGF -- Non-Electric Generating Facility
NEI -- National Emissions Inventory
NESHAP -- National Emission Standards for Hazardous Air Pollutants
ng/J -- Nanogram per Joule
NMIM -- National Mobile Inventory Model
NOAA -- National Oceanic and Atmospheric Administration
NO_X -- Nitrogen Oxides
NO_y -- Nitrogen Species
NSCR -- Non-Selective Catalytic Reduction
NTRD -- New Technology Research and Development Program
O_3 -- Ozone
OGV -- Ocean-Going Vessel
PAYD -- Pay As You Drive
PBL -- Planetary Boundary Layer
PEI -- Periodic Emissions Inventory
PERP -- Portable Engine Registration Program
PiG -- Plume-in-Grid
PM -- Particulate Matter
$PM_{2.5}$ -- Particulate Matter less than 2.5 microns
ppb -- Parts Per Billion
ppbC -- Parts Per Billion Carbon
ppbv -- Parts Per Billion by Volume
ppm -- Parts Per Million
PSCF -- Potential Source Contribution Factors
PSDB -- Point Source Database
psia -- Pounds per Square Inch Absolute
PUC -- Public Utility Commission
RACT -- Reasonably Available Control Technology
RACM -- Reasonably Available Control Measure
RFP -- Reasonable Further Progress
RMSE -- Root Mean Square Error
ROP -- Rate-of-Progress
RRF -- Relative Reduction Factor
SB -- Senate Bill
SCAQMD -- South Coast Air Quality Management District
scfm -- Square Cubic Feet per Minute
SCR -- Selective Catalytic Reduction
SEP -- Supplemental Environmental Programs
SETPMTC -- Southeast Texas Photochemical Modeling Technical Committee
SIC -- Standard Industrial Classification
SIP -- State Implementation Plan
SNCR -- Selective Non-Catalytic Reduction
SOV -- Single Occupancy Vehicle
STP -- Surface Transportation Program
SWCV -- Solid Waste Collection Vehicle
TAC -- Texas Administrative Code
TACB -- Texas Air Control Board
TCAA -- Texas Clean Air Act
TCEQ -- Texas Commission on Environmental Quality (commission)
TCM -- Transportation Control Measure
TDM -- Travel Demand Model
TERP -- Texas Emission Reduction Plan
TexAQS 2000 -- Texas Air Quality Study 2000
TexAQS II -- Texas Air Quality Study 2006

TKE -- Turbulent Kinetic Energy
TNMHC -- Total Nonmethane Hydrocarbon
TNRCC -- Texas Natural Resource Conservation Commission
tpd -- tons per day
tpy -- tons per year
TSE -- Truck Stop Electrification
TTI -- Texas Transportation Institute
TUC -- Texas Utility Code
TxDOT -- Texas Department of Transportation
TxLED -- Texas Low Emission Diesel
USC -- United States Code
VMEP -- Voluntary Mobile Source Emissions Reduction Program
VMT -- Vehicle Miles Traveled
VOC -- Volatile Organic Compound
VRU -- Vapor Recovery Unit
ZEB -- Zero Emission Bus
ZEV -- Zero Emissions Vehicle

DALLAS-FORT WORTH OZONE NONATTAINMENT AREA
EIGHT-HOUR ATTAINMENT DEMONSTRATION

TABLE OF CONTENTS

Executive Summary

List of Acronyms

Table of Contents

List of Appendices

List of Tables

List of Figures

Chapter 1: Background and Introduction
1.1 General
1.2 Health Effects
1.3 Public/Stakeholder Participation
1.4 Social and Economic Considerations
1.5 Fiscal and Manpower Resources

Chapter 2: Photochemical Modeling
2.1 Introduction
2.2 Episode Selection
2.3 Model Selection and Set-up
2.4 Meteorological Modeling
2.5 Emissions Inventory
2.6 1999 Base Case, Baseline, and Model Performance Evaluation
2.7 Development of DFW 2009 Future Baseline and Sensitivity Tests
2.8 DFW Future Baseline Case (2009) Modeling Results
2.9 DFW Future Case (2009) With Controls Modeling Results
2.10 Bibliography and References

Chapter 3: Corroborative Analysis
3.1 Overview
3.2 Ozone Design Value Trends
3.3 Ozone Variability Analysis
3.4 NO_X and VOC Trends
3.5 NO_X and VOC Limitation Analysis
3.6 Local Contributions and Federal Preemption Issues
3.7 Background Ozone and Transport Contributions
3.8 2010 Mobile Emissions Modeling Sensitivity
3.9 Conclusions
3.10 References

Chapter 4: Required Control Strategy Elements
4.1 Overview of Existing Control Strategies

4.2 NO_X and VOC Control Measures
4.3 Reasonably Available Control Technology (RACT) Analysis
4.4 Reasonably Available Control Measures (RACM) Analysis
4.5 Motor Vehicle Emissions Budget (MVEB)
4.6 Contingency Measures

Appendices

LIST OF APPENDICES

Appendix	Appendix Name
A	Emissions Inventories Used in Episode Modeling
B	Emissions Inventory Development
C	Spatial Plots of the Daily Maximum Eight-Hour Ozone in the DFW 4-km Domain Using CAMx 4.03 (left), CAMx 4.31 (center), and CAMx 4.40 Beta (right) for Each Episode Day
D	DFW Future Case (2009) Sensitivity Tests
E	1999 Base Case/Baseline Run Log
F	Transportation Control Measures for the DFW Eight-Hour Ozone SIP
G	DFW Nonattainment Area Ozone Conceptual Model
Attachment 1	Start of the School Year's Effect on the DFW Area
Attachment 2	MAPPER Analysis of VOC & NO_X Limitations in the DFW Area
Attachment 3	Weekday/Weekend Analysis of Ozone in the DFW Area
Attachment 4	Characterization of VOC Reactivity in the DFW Area
Attachment 5	Auto-GC Analysis in the DFW Area
H	NCTCOG Submittal of On-Road and Non-Road Emissions Reductions Benefits
I	Assessment of NO_X Emissions Reduction Strategies for Cement Kilns - Ellis County, Final Report (July 14, 2006)
J	Reasonably Available Control Technology Analysis
K	Information Sources Used in the Emission Control Strategy Development Process
L	Emission Reduction Control Strategies, Environ Final Report
M	RACM Analysis of Area and Point Source Emission Control Measures

LIST OF TABLES

Number	Table Name
Table 2-1	MM5 and CAMx Vertical Layer Structure
Table 2-2	1999 Baseline Model Inputs
Table 2-3	DFW 1999 Baseline Design Value Calculations
Table 2-4	DFW 2009 Baseline RRF Calculations Using CAMx 4.31 and .a2 Emissions
Table 2-5	2009 Design Value Calculations
Table 2-6	2009 Control Package Emission Reductions (Combination 10 compared to .a2 Baseline)
Table 2-7	Weekday NO_x Emissions (tpd) for 2009 with DFW Combination 10 Controls
Table 2-8	Weekday VOC Emissions (tpd) for 2009 with DFW Combination 10 Controls
Table 2-9	DFW Future Case RRF Calculations with Combination 10 Controls
Table 2-10	Future Design Value Calculations with Combination 10 Controls
Table 3-1	DFW Eight-Hour Ozone Trends
Table 3-2	Relative Reduction Factors (RRFs) for New Monitors
Table 3-3	Episode Average Ozone Contributions by APCA Source Region in DFW Future Case (2009)
Table 3-4	Future Case (2009) Ozone Design Values
Table 4-1	DFW Modeled NO_x Reduction Estimates
Table 4-2	Summary of Control Strategies NO_x Reduction Estimates for the DFW Eight-Hour Ozone Attainment Demonstration
Table 4-3	DFW five percent Increment of Progress Reductions
Table 4-4	Total 2009 Estimated Emission Reductions by TCM Program
Table 4-5	NCTCOG Voluntary Mobile Emission Reductions
Table 4-6	Federal Mobile/Engine Standards Implementation Schedule
Table 4-7	Tuesday, August 17 On-Road Emission Trends for Nine-County DFW From 1999-2012
Table 4-8	Change in On-Road Emissions for Tuesday, August 17 in Nine-County DFW From 1999-2012
Table 4-9	2009 Attainment Demonstration Motor Vehicle Emissions Budget for the Nine-County DFW Area

LIST OF FIGURES

Number	Figure Name
Figure 2-1	Texas Ozone Season
Figure 2-2	Wind Directions Associated with DFW Eight-Hour Ozone Episodes
Figure 2-3	DFW Ozone vs. Morning and Afternoon Wind Speeds
Figure 2-4	DFW Sites with High Eight-Hour Design Values
Figure 2-5	August 13-22, 1999, Daily Max Ozone and Number of Stations with Exceedances
Figure 2-6	DFW Main Modeling Fine (4-km) Grid with Ozone Monitor Sites
Figure 2-7	DFW Modeling Grids, Original Nesting and Expanded Grids
Figure 2-8	MM5 and CAMx Modeling Grids with the Expanded Domain
Figure 2-9	Boundary Conditions Used for the Expanded Domain in DFW Modeling
Figure 2-10	Daily Site-Averaged MM5 Wind Performance for Runs 5, 6, and 7 in the DFW 4 km Modeling Domain
Figure 2-11	Daily Site-Averaged MM5 Temperature Performance for Runs 5, 6, and 7 in the DFW 4 km Modeling Domain
Figure 2-12	Daily Site-Averaged MM5 Humidity Performance for Runs 5, 6, and 7 in the DFW 4 km Modeling Domain
Figure 2-13	Bias and Gross Error Plotted in Error Space for Eight-Hour Ozone CAMx Modeling Runs
Figure 2-14	Base Case Model Performance Statistics for Eight-Hour Ozone in DFW
Figure 2-15a	Hourly Time Series for the 1999 Baseline Comparing Three CAMx Versions
Figure 2-15b	Hourly Time Series for the 1999 Baseline Comparing Three CAMx Versions
Figure 2-15c	Hourly Time Series for the 1999 Baseline Comparing Three CAMx Versions
Figure 2-16	DFW 40 Ton Test Response Chart
Figure 2-17	Comparison of EPA RRF Calculation Method with Daily Calculation Method
Figure 2-18	Spatial Plots of the Daily Maximum Eight-Hour Ozone in 2009 with Combination 10 Controls, and Differences from the 2009 Baseline for Each Episode Day in the DFW 4 km Domain
Figure 2-19	Change in DFW Eight-Hour Ozone Design Values
Figure 3-1	One-Hour and Eight-Hour Ozone Design Values in the DFW Area (1991-2006)
Figure 3-2	DFW One-Hour Ozone Design Values and Population
Figure 3-3	DFW Eight-Hour Ozone Design Values and Population
Figure 3-4	Frisco Eight-Hour Ozone Trends
Figure 3-5	Denton Eight-Hour Ozone Trends
Figure 3-6	One-Hour and Eight-Hour Ozone Exceedances in the DFW Area from 1990 to 2006
Figure 3-7	Average Eight-Hour Ozone Exceedance Days vs. Average Number of Monitors in the DFW Area from 1990 to 2006
Figure 3-8	Number of Actual Eight-Hour Ozone Exceedance Days Compared to the Number of Expected Eight-Hour Ozone Exceedance Days in the DFW Area from 1990 to 2006
Figure 3-9	DFW Ozone Trends Adjusted for Wind Speed
Figure 3-10	Percent of Total Eight-Hour Ozone Exceedance Days Above and Below 95 ppb in the DFW Area from 1990 to 2006
Figure 3-11	Long Term DFW Trend for Exceedances Greater Than 95 ppb

Figure 3-12	DFW Seasonal Average Eight-Hour Daily Maximum Ozone Adjusted for Meteorological Factors
Figure 3-13	1999 Anthropogenic NO_X Emissions by Source Category in the DFW Area
Figure 3-14	1999 Anthropogenic VOC Emissions by Source Category in the DFW Area
Figure 3-15	NO_X Emission Inventory Trend in the DFW Area from 1990 to 2003
Figure 3-16	VOC Emission Inventory Trend in the DFW Area from 1990 to 2003
Figure 3-17	NO_X Emission Inventory Trends for the 110-County East Texas Area from 1990 to 2003
Figure 3-18	Spatial Patterns of the Extent of Reaction in the DFW Area
Figure 3-19	Future Case CAMx Response to VOC Reductions
Figure 3-20	Future Case CAMX Response to NO_X Reductions
Figure 3-21	DFW Future Case (2009) NO_X Emissions by Source Category
Figure 3-22	NO_X Sources Directly Regulated by TCEQ
Figure 3-23	Eight-Hour Ozone in the DFW Area from 1998 to 2003
Figure 3-24	Site Specific APCA Contributions in DFW Future Case (2009)
Figure 4-1	Weekday On-Road Emission Inventory Trends in Nine-County DFW from 1999-2012

CHAPTER 1: BACKGROUND AND INTRODUCTION

1.1 GENERAL

"The History of the Texas State Implementation Plan (SIP)," a comprehensive overview of the SIP revisions submitted to Environmental Protection Agency (EPA) by the State of Texas, is available at the following web site:
http://www.tceq.state.tx.us/implementation/air/sip/sipintro.html#History.

Eight-Hour Ozone Standard

As of June 15, 2004, the Dallas-Fort Worth (DFW) eight-hour ozone nonattainment area is classified as a moderate area under the 1990 Federal Clean Air Act Amendments (FCAA) (42 United States Code (USC) §§7401 et. seq.). The DFW area is therefore required to attain the eight-hour ozone standard of 0.08 ppm by June 15, 2010, and to submit a state implementation plan (SIP) revision by June 15, 2007 (69 FR 23857). For the DFW area, defined as Collin, Dallas, Denton, Ellis, Johnson, Kaufman, Parker, Rockwall, and Tarrant Counties, the TCEQ has developed an attainment demonstration in accordance with 42 USC §7410. The one-hour ozone national ambient air quality standard (NAAQS), which preceded the eight-hour ozone standard, was revoked June 15, 2005 (69 FR 23951).

On April 30, 2004, the United States Environmental Protection Agency (EPA) published its Phase I Eight-Hour Implementation Rule. In 40 CFR §51.905(a)(ii) and subsequent guidance, the EPA provided three options for areas such as DFW that did not have an approved one-hour ozone attainment plan at the time of designation:

A. Submit a one-hour attainment demonstration no later than one year after designation (by June 15, 2005);
B. Submit an eight-hour ozone plan no later than one year after designation (by June 15, 2005) that provided a five percent increment of emissions reductions from the area's 2002 emissions baseline, in addition to federal and state measures already approved by the EPA and achieving those reductions by June 15, 2007; or
C. Submit an eight-hour ozone attainment demonstration by June 15, 2005.

Texas selected option B, the Five Percent Increment of Progress (IOP) plan, as a technically sound and expeditious approach to initiating the reductions ultimately needed for attainment of the eight-hour ozone standard.

DFW Five Percent IOP SIP

The Five Percent IOP SIP, adopted by the commission on April 27, 2005, contained several elements:

- 2002 Periodic Emissions Inventory (PEI) for the nine-county DFW eight-hour ozone nonattainment area;
- A five percent reduction in emissions from the 2002 emissions inventory baseline;
- Identification of the control measures to achieve the necessary nitrogen oxides (NO_X) and volatile organic compounds (VOC) emission reductions;
- Motor Vehicle Emissions Budgets (MVEBs) for use in transportation conformity demonstrations.

DFW Eight-Hour Ozone Attainment Demonstration SIP

This eight-hour ozone attainment demonstration for the DFW area contains photochemical modeling and weight of evidence, including corroborative analysis and additional measures not included in the model, to demonstrate attainment of the eight-hour ozone standard by June 15, 2010.

In addition to the existing control strategies in the DFW area, this SIP revision includes new rules for the following sources.

- DFW Cement Kilns
- DFW Electric Generating Facilities (EGFs)
- DFW Industrial, Commercial, and Institutional (ICI) Major Sources
- DFW Minor Sources
- East Texas Combustion Source in 33 Counties Beyond the DFW area

The revision includes additional commitments for voluntary mobile emissions reduction program (VMEP) and transportation control measures (TCM). The revision also contains the reasonably available control measures (RACM) analysis, reasonably available control technologies (RACT) analysis, contingency measures, emissions inventories, and motor vehicle emissions budgets (MVEB).

DFW One-Hour Ozone Background

An understanding of the previous DFW SIP and subsequent revisions is helpful in examining the current eight-hour ozone SIP revision. The DFW one-hour ozone nonattainment area (Collin, Dallas, Denton, and Tarrant Counties) was classified in 1991 as moderate in accordance with the 1990 FCAA amendment. As a moderate area, DFW was required to demonstrate attainment of the one-hour ozone standard by November 15, 1996. Ambient air monitoring data for the years 1994-96, however, showed that the one-hour ozone standard was exceeded more than one day per year over the three-year period. As a result, EPA reclassified the DFW area from moderate to serious (effective March 20, 1998) for failure to attain the one-hour ozone standard by the November 1996 deadline. EPA required the State of Texas to submit a SIP revision within one year that showed attainment of the NAAQS and addressed requirements for serious ozone nonattainment areas.

1.1.1 March 1999

The TCEQ submitted a SIP revision containing a Post-1996 Rate of Progress (ROP) SIP demonstration to the EPA on March 18, 1999. The photochemical modeling contained in the revision indicated that additional reductions in NO_X emissions would be needed to attain the standard by November 1999. The following rules were developed and included in the SIP:

- Reasonably Available Control Technology (RACT) for NO_X point sources;
- Nonattainment New Source Review (NSR) for NO_X point sources; and
- Revisions resulting from the change in the major source threshold for RACT applicability for VOC.

Additionally, the commission indicated that, due to time constraints, the Post-1996 ROP SIP would not have all the rules adopted that were necessary to bring the DFW area into attainment by the November 1999 deadline and that a complete attainment demonstration would be submitted in the spring of 2000. The EPA determined that the Post-1996 ROP SIP was incomplete.

Additional local control strategies were necessary for DFW to reach attainment. To develop further control strategy options to augment the federal and state programs in the Post-1996 ROP SIP, the DFW area established the North Texas Clean Air Steering Committee (NTCASC). The committee members include local elected officials, business leaders, and other community stakeholders. This committee identified specific control strategies for review by technical subcommittee members.

After the attainment deadline of November 15, 1999, for serious areas under the one-hour ozone standard passed, the EPA had not made a determination regarding the DFW area's attainment status. Furthermore, technical data became available suggesting that DFW was significantly impacted by transport and regional background levels of ozone. Therefore, the commission began viewing the reductions for strategies needed for the Houston-Galveston-Brazoria (HGB) area and regional rules as a necessary and integral component in the strategy for DFW's attainment of the one-hour ozone strategy.

1.1.2 April 2000

The Post-1996 ROP SIP was not yet approved by EPA by the next commission action. On April 19, 2000, the commission adopted a SIP revision and associated rules for the DFW one-hour ozone attainment demonstration. The April 2000 One-Hour Ozone Attainment Demonstration SIP contained a number of control strategies and the following elements:

- Photochemical modeling of specific control measures and future state and national rules for attainment of the one-hour ozone standard in the DFW area by the attainment deadline of November 15, 2007.
- A modeling demonstration that showed air quality in the DFW area was influenced at times by transport from the HGB nonattainment area. Under EPA's July 16, 1998, transport policy, if photochemical modeling demonstrated that emissions from an upwind area located in the same state and with a later attainment date interfered with the downwind area's ability to attain, the downwind area's attainment date could be extended to no later than that of the upwind area. For the DFW area, this would extend the attainment date to November 15, 2007, the same attainment date as the HGB area.
- Identification of the VOC and NO_X emissions reductions necessary to attain the one-hour ozone standard by 2007. The reductions of 141 tpd NO_X from federal measures and 225 tpd NO_X from state measures resulted in a total of 366 tpd NO_X reductions for the attainment demonstration.
- A 2007 MVEB for transportation conformity.
- A commitment to perform and submit a mid-course review by May 1, 2004.

At the time it was submitted, the April 2000 One-Hour Ozone Attainment Demonstration SIP would have allowed the EPA to determine that the DFW area should not be reclassified from serious to severe under the conditions of the EPA's July 16, 1998, transport policy.

1.1.3 August 2001

The next commission action was required by legislative mandate. Senate Bill 5 (SB5), passed by the 77th Texas Legislature in May 2001, required the repeal of two rules contained in the April 2000 SIP revision. The first rule restricted the use of construction and industrial equipment (non-road, heavy-duty diesel equipment rated at 50 hp or greater). The second rule required the replacement of diesel-powered construction, industrial, commercial, and lawn and garden equipment rated at 50 hp or greater with newer Tier 2 or Tier 3 equipment. The Texas Emissions Reduction Plan (TERP) grant incentive program established by SB5 replaced the NO_X emissions reductions previously claimed for the two programs. The commission implemented the legislative mandate of SB5 by submitting the rule repeals as part of a SIP revision adopted in August 2001.

1.1.4 March 2003

On March 5, 2003, the SIP was further revised to include the following.

- The adoption of revised Chapter 117 NO_X emission limits for cement kilns.
- The estimation of NO_X reductions from energy efficiency measures, using a methodology that was to be further refined before energy efficiency credit was formally requested in the SIP.

- The commitment to perform modeling with MOBILE6, the latest version of the EPA's emission factor model for mobile sources.

Meanwhile, the EPA's July 16, 1998, transport policy, on which the extension of the DFW area's attainment to November 15, 2007, was based, was challenged by environmental groups. A suit was filed challenging the extension of the Beaumont-Port Arthur (BPA) area's attainment date based on transport from the HGB area. On December 11, 2002, the United States Fifth Circuit Court of Appeals ruled that the EPA was not authorized to extend BPA's attainment date based on transport. The EPA published a final action in the Federal Register on March 30, 2004, reclassifying BPA to serious with an attainment date of November 15, 2005, and requiring a new attainment demonstration to be submitted by April 30, 2005. Although the court decision was specifically for BPA, the direct implication for DFW was that the EPA could not approve extensions of the DFW one-hour ozone attainment date past 1999, the date mandated by the FCAA for serious areas. In addition, the EPA could not approve the April 2000 One-Hour Ozone DFW Attainment Demonstration SIP.

1.1.5 Progress to Date

Since the early 1990s, when the DFW area was designated as nonattainment for the one-hour ozone standard, much has been done to bring the area into attainment with federal air quality standards. Contributions to improved air quality in the DFW area include: TCEQ implemented control strategies, local control strategies adopted by the North Central Texas Council of Governments (NCTCOG), and on-road and non-road mobile source measures implemented by the EPA.

The control strategies implemented so far have significantly improved air quality in the DFW area. The one-hour and the eight-hour ozone design values both show decreasing trends over the past 15 years. The one-hour design value has decreased about 11.4 percent since 1991, and the eight-hour ozone design value has decreased by about 8.6 percent. In 2006, the one-hour ozone design value was measured at 124 ppb, which demonstrates attainment of the former one-hour ozone standard. The eight-hour ozone design value decreased from 105 ppb in 1991 to 96 ppb in 2006.

1.2 HEALTH EFFECTS

In 1997, the EPA revised the NAAQS for ozone from a one-hour to an eight-hour standard based on scientific data that indicated that the eight-hour standard provides better protection of public health from longer-term exposures to moderate levels of ozone. To support the eight-hour ozone standard, the EPA provided information that indicated that even low levels of ozone can significantly decrease lung capacity temporarily in some healthy adults and cause inflammation of lung tissue, aggravate asthma, and make people more susceptible to respiratory illnesses such as bronchitis and pneumonia.

Children are at a higher risk from exposure to ozone, since they breathe more air per pound of body weight than adults and because children's respiratory systems are still developing. Children also spend a considerable amount of time outdoors during summer and during the start of the school year (August-October) when ozone levels are typically higher. Adults most at risk to ozone exposure are outdoor workers, people outside exercising, and individuals with preexisting respiratory diseases.

1.3 PUBLIC/STAKEHOLDER PARTICIPATION

1.3.1 Control Strategy Development

The TCEQ contracted with the NCTCOG to evaluate and quantify potential control measures for the DFW eight-hour ozone attainment demonstration. The NCTCOG sought public comment throughout the entire control strategy development process. A series of public meetings were held in the DFW area during June and September 2005 and public stakeholder meetings were held in Fort Worth, Arlington, and Richardson in September and December 2005. In addition, control strategy development was discussed at public meetings of the NTCASC from June 2005 through late 2006. The NCTCOG Regional Transportation Council and Surface Transportation Technical Committee also discussed control strategy development at several of the groups' meetings. Public comment was also sought at a meeting of the Clean Cities Technical Coalition in July 2005. For more information regarding the NCTCOG's control strategy catalog, please see Chapter 4, Section 4.5.2 *Control Strategy Development to Determine Appropriate RACM* or visit the NCTCOG website at http://www.nctcog.org/trans/air/sip/future/presentations.asp.

1.3.2 SIP and Rule Development

The TCEQ held two open-participation DFW Eight-Hour Ozone SIP & Rules Stakeholder Group meetings to discuss concepts of potential rules for the nine-county DFW ozone nonattainment area and to hear the public's ideas on potential rulemaking concepts and the development of Texas' clean air plan. The meetings were held on June 20 and 21, 2006, in Irving. In these meetings, the TCEQ presented attendees with a brief background of the DFW SIP, a review of the technical work that had been completed to date, and an overview of the existing control measures for NO_X and VOC. In addition to these meetings, the TCEQ held a meeting of the Northeast Texas Stakeholder Group to discuss a potential rulemaking that would implement NO_X emission specifications for certain stationary, gas-fired, reciprocating internal combustion engines. This meeting was held on September 7, 2006, in Longview. For more information on public and stakeholder participation, please visit www.tceq.state.tx.us/implementation/air/sip/dfw.html.

1.3.3 Public Hearing Information

The commission held public hearings at the following times and locations:

CITY	DATE	TIME	LOCATION
Houston	January 29, 2007	2:00 P.M.	Houston-Galveston Area Council 3555 Timmons Lane, Houston, TX 77027 Conference Room A, (2nd floor)
Houston	January 29, 2007	6:00 P.M.	Houston-Galveston Area Council, 3555 Timmons Lane, Houston, TX 77027, Conference Room A, (2nd floor)
Dallas	January 31, 2007	7:00 P.M.	Dallas Public Library Auditorium 1515 Young St., Dallas, TX 75201
Arlington	February 1, 2007	2:00 P.M.	Arlington City Hall 101 W. Abram Street, Arlington, TX 76010
Midlothian	February 1, 2007	6:00 P.M.	Midlothian Conference Center 1 Community Center Circle, Midlothian, TX 76065
Longview	February 6, 2007	2:00 P.M.	Longview Public Library 222 W. Cotton Street, Longview, TX 75601
Austin	February 8, 2007	2:00 P.M.	Texas Commission on Environmental Quality 12100 Park 35 Circle, Austin, TX 78753 Building E, Room 201S

The public comment period opened on December 29, 2006, and closed on February 12, 2007. Written comments were accepted via mail, fax, or through the TCEQ e-comment system.

1.4 SOCIAL AND ECONOMIC CONSIDERATIONS

For a detailed explanation of the social and economic issues involved with any of the measures, please refer to the preambles that precede each proposed rule package accompanying this SIP.

1.5 FISCAL AND MANPOWER RESOURCES

The state has determined that its fiscal and manpower resources are adequate and will not be adversely affected through the implementation of this plan.

CHAPTER 2: PHOTOCHEMICAL MODELING

2.1 INTRODUCTION

This chapter describes modeling conducted in support of the eight-hour ozone attainment demonstration SIP revision for the DFW nine-county nonattainment area. The 1990 FCAA requires that attainment demonstrations be based on photochemical grid modeling or any other analytical methods determined by the EPA to be at least as effective. The EPA's recent "Guidance on the Use of Models and Other Analyses in Attainment Demonstrations for the Eight-Hour Ozone NAAQS" (October 2005) recommends new procedures for determining whether a control strategy package will lead to attainment of the eight-hour NAAQS for ozone.

The guidance, which is the latest released by the EPA, recommends several qualitative methods for preparing attainment demonstrations that acknowledge the limitations and uncertainties of photochemical models when used to project ozone concentrations into future years. First, the guidance recommends using model outputs in a relative sense and applying the model response to the observed ozone data. Second, the guidance recommends using available air quality, meteorology, and emissions data to develop a conceptual model for eight-hour ozone formation and to use that analysis in episode selection. Third, the guidance recommends using supportive analyses (Weight of Evidence) to supplement and corroborate the model results and support the adequacy of a proposed strategy package.

In early 2003, as the TCEQ was preparing to move forward with the Mid-Course Review (MCR) for the DFW area, the EPA announced its plans to begin implementation of the eight-hour ozone standard. On June 2, 2003, the Federal Register published EPA's proposed Implementation Rule for the Eight-Hour Ozone Standard. In the same timeframe, EPA also formalized its intentions to designate areas for the eight-hour ozone standard by April 15, 2004, meaning states would need to reassess their efforts to date and control strategies to address the new standard by 2007.

Recognizing that existing one-hour ozone nonattainment areas would soon be subject to the eight-hour ozone standard, and in an effort to efficiently manage the state's limited resources, the TCEQ developed an approach that addressed the commitments made under the one-hour ozone standard while moving forward on the more stringent eight-hour ozone standard. Using the same episode for both one-hour and eight-hour modeling provided the opportunity to build upon a well-developed and properly performing foundation, as well as the opportunity to update emissions inventory data, use the most current modeling tools, enhance the photochemical grid modeling, and revise control strategies, if necessary.

This attainment demonstration uses photochemical modeling in combination with trends, transport analyses, and supplementary data to show that the DFW nine-county nonattainment area is on a path to attain the 0.08 ppm eight-hour ozone standard by June 15, 2010. The additional data and analysis in the Weight of Evidence (WoE) also supports the attainment conclusion.

Overview of Ozone Photochemical Modeling Process

Ozone is a secondary pollutant; it is not generally emitted directly into the atmosphere. Ozone is created in the atmosphere by a complex chemical reaction between sunlight and several primary pollutants. The chemical reaction requires ultraviolet energy from sunlight. The primary pollutants fall into two groups, nitrogen oxides (known as NO_x) and volatile organic compounds (known as VOC). As a result of these multiple factors, ozone events are most common during the summer and concentrations peak during the day and fall during the night and early morning hours.

Ozone chemistry is complex, involving more than 80 chemical reactions and hundreds of chemical compounds. As a result, ozone cannot be evaluated using simple dilution and dispersion algorithms. Due to the chemical complexity and the requirement to evaluate the

effectiveness of future controls, the EPA's guidance strongly recommends using photochemical computer models to analyze ozone issues. Computer simulations are the most effective tools to address both the chemical complexity and the future case evaluation.

Ozone Modeling

Ozone modeling involves two major phases, the base case and the future case (with substeps in each phase). The purpose of the base case is to evaluate procedures and to ensure that the model is performing correctly. The purpose of the future case is to evaluate the effectiveness of controls and to demonstrate attainment.

Base Case Modeling

Base case modeling involves several steps. First, historical episodes must be analyzed extensively to determine what factors are associated with ozone formation in the area, followed by development a conceptual model that identifies those factors. The technical team then selects an episode to model (a recent, real-world ozone event) that is representative of the factors, develops a modeling protocol (plan) that describes the process to be followed to evaluate the ozone in the urban area, and submits the plan to the EPA for approval.

The next step is to generate and quality assure the emissions and meteorological data for the episode. Then the meteorological data and NO_X and VOC emissions information are added into the computer model and the ozone model output is evaluated. The final step is to validate the base case modeling results by comparing them to the real measurements for ozone and precursor compounds to be sure that the model is performing correctly. The model output is assessed based on subjective analysis and statistical tests described in the EPA's 2005 modeling guidance. Satisfactory performance of the base case model demonstrates that the model is giving right answers for the right reasons; then the model is ready to be used for future case modeling.

Future Case Modeling

Future case modeling is designed to evaluate how much ozone will be created in the future. The scientific question is: If the same meteorology were to occur in the future, how much ozone would be formed? To answer this question, a future case emissions inventory must be developed that includes the impact of economic growth in the region, as well as all of the state and federal emission reductions that will be in effect in the future.

The first step of the future base case is to run the model with the emissions projected into the future while applying only the existing emissions reduction strategies to determine how well the model responds to existing controls, including state and federal mandated measures. The relative response factor (RRF) is multiplied by the baseline ozone measured during the representative base period. If the product of the RRF and baseline ozone is less than 0.08 ppm, the attainment demonstration is satisfied. If the existing emission reduction strategies are not sufficient to offset the growth and reduce ozone to attainment levels, then additional controls may be needed. The second step of the future case modeling is to test new, additional strategies to determine what combination of reductions would be most effective to bring the area into attainment.

2.2 EPISODE SELECTION

The EPA's guidance for episode selection has evolved over the last several years as the focus has shifted from the one-hour ozone standard to the eight-hour ozone standard, as explained in Section 2.1. The current episode was selected to address both the one-hour and eight-hour ozone standards. The August 13-22, 1999, episode was selected because it included both one-hour and eight-hour ozone exceedance events and was consistent with the conceptual model for ozone formation in the DFW area. As required by the EPA (EPA, 2005 a, b) several different candidate episodes were considered, and the final selection was based on evaluation of the meteorology associated with the events, as well as the availability of real time emissions and precursor measurements.

Much of the early development work for this eight-hour episode was done in support of a planned one-hour ozone MCR before the EPA issued the draft eight-hour ozone guidance. The one-hour ozone MCR modeling provided a strong foundation for the eight-hour ozone modeling, and since that time, the August 13-22, 1999, eight-hour ozone episode has been further developed and improved. The development process evolved over time, and improvements were added in a continuous cycle involving the incorporation of technical insight, best practices, model upgrades, and performance evaluation.

The August 13-22, 1999, DFW ozone episode is ten days long and includes nine days with eight-hour ozone exceedances. The episode includes a full synoptic cycle with a sequential pattern of different daily wind directions reflecting wind directions associated with DFW ozone events. The episode also includes a full ozone cycle, low ozone concentrations at the beginning and end with a period of high ozone concentrations in the middle, reflecting near calm winds. Weekdays and weekends were both included to properly reflect the occurrence of eight-hour ozone events in the DFW area.

Since the episode was selected before the EPA's eight-hour ozone guidance was finalized, some of the DFW early one-hour ozone selection criteria are not in the most recent EPA guidance (2005). However, since a large body of work has been developed with the current DFW episode, and significant performance improvements have been made, the EPA approved the use of the August 1999 episode for this eight-hour ozone demonstration. The following discussion will address how the August 1999 episode meets the most recent EPA selection criteria (EPA-454/R-05-002, 2005).

EPA Guidance for Episode Selection

Since 1999, the EPA has recommended selecting ozone episodes that represent the most typical and frequent ozone events based upon analysis of the meteorological and geographical patterns associated with high ozone concentrations in the area. The EPA also recommends selecting extended episodes that encompass full synoptic cycles from ramp-up to a high ozone period to a ramp-down to allow for a more complete evaluation of model performance through the full cycle. The EPA recommends (EPA, 1999) that at least four criteria be used to select episodes that are appropriate to model:

- Choose a mix of episodes reflecting a variety of meteorological conditions that frequently correspond with observed eight-hour ozone daily maxima greater than 84 ppb at multiple monitoring sites.
- Model periods in which observed eight-hour ozone daily maximum concentrations are close to the average fourth high eight-hour ozone daily maximum ozone concentrations.
- Model periods for which extensive air quality data and meteorological databases exist.
- Model a sufficient number of days so that the modeled attainment test applied at each monitor violating the NAAQS is based on multiple days.

DFW Ozone Episode Selection Process

An episode selection analysis was performed to identify time periods with representative high one-hour and eight-hour ozone levels suitable for developing regional scale modeling (Environ, 2002 and Environ 2003b). Episode selection was based upon the considerations developed in those studies.

Ozone episodes selected for modeling should represent the most frequent, typical, and representative patterns associated with high ozone in the DFW area. Detailed analysis of individual ozone events for the conceptual model has shown that although DFW ozone is associated with winds on different days blowing from the northeast through the east, southeast, and south, the common factor in all ozone events is light wind speeds. Light winds are typically less than seven mph.

The TCEQ evaluated the following factors as part of the episode selection process in determining the best candidate was the period of August 13-22, 1999.

- The best time period from which to select additional episodes to model is during August-September when ozone episodes occur most frequently in Texas and when the highest design values are established at most of the area's monitors. The August 13-22, 1999, episode occurs during the core of the Texas ozone season, as shown by Figure 2-1: *Texas Ozone Season.*

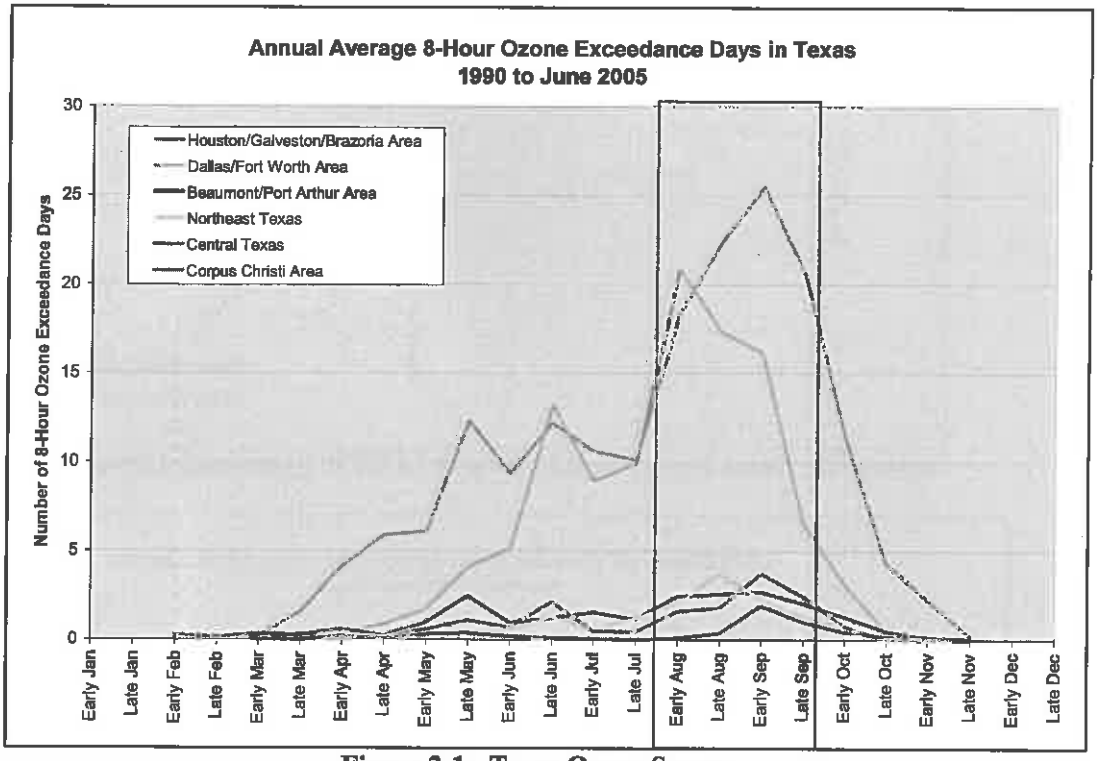


Figure 2-1: Texas Ozone Season

- Recent episodes are preferable to older episodes because recent episodes better represent the current emissions inventory, including mobile and point source configurations. At the time of the decision, August 13-22, 1999, was the most recent and representative episode.
- Well-monitored episodes (with more meteorology, VOC, and NO_x data) are preferable to data-poor episodes. Additional data allow for a more thorough model evaluation and provide the information necessary to understand the processes leading to high ozone. During 1999, there were nine active ozone monitors, six NO_x monitors, and one VOC monitoring gas chromatograph system.
- Episodes should include a variety of wind directions and speeds associated with high ozone concentrations. The August 13-22, 1999, episode included a variety of wind directions associated with a complete synoptic cycle, as shown by Figure 2-2: *Wind Directions Associated with DFW Eight-Hour Ozone Episodes.* The August 13-22, 1999, episode also included a variety of morning and afternoon wind speeds including near calm conditions, as shown by Figure 2-3: *DFW Ozone vs. Morning and Afternoon Wind Speeds.*

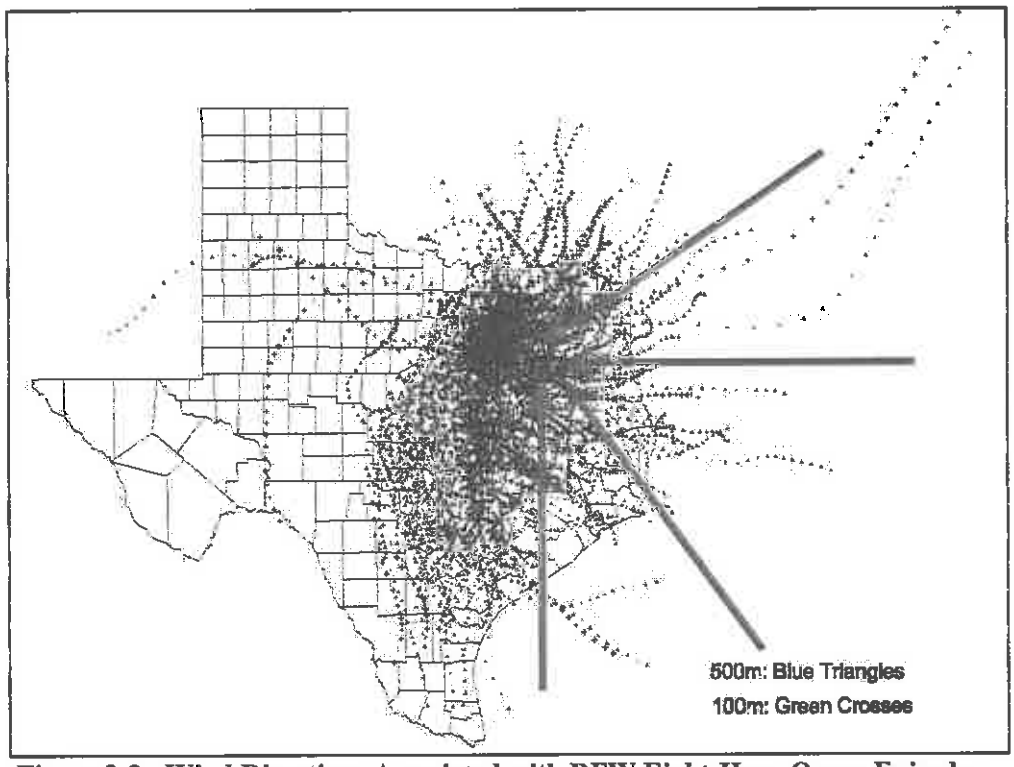


Figure 2-2: Wind Directions Associated with DFW Eight-Hour Ozone Episodes

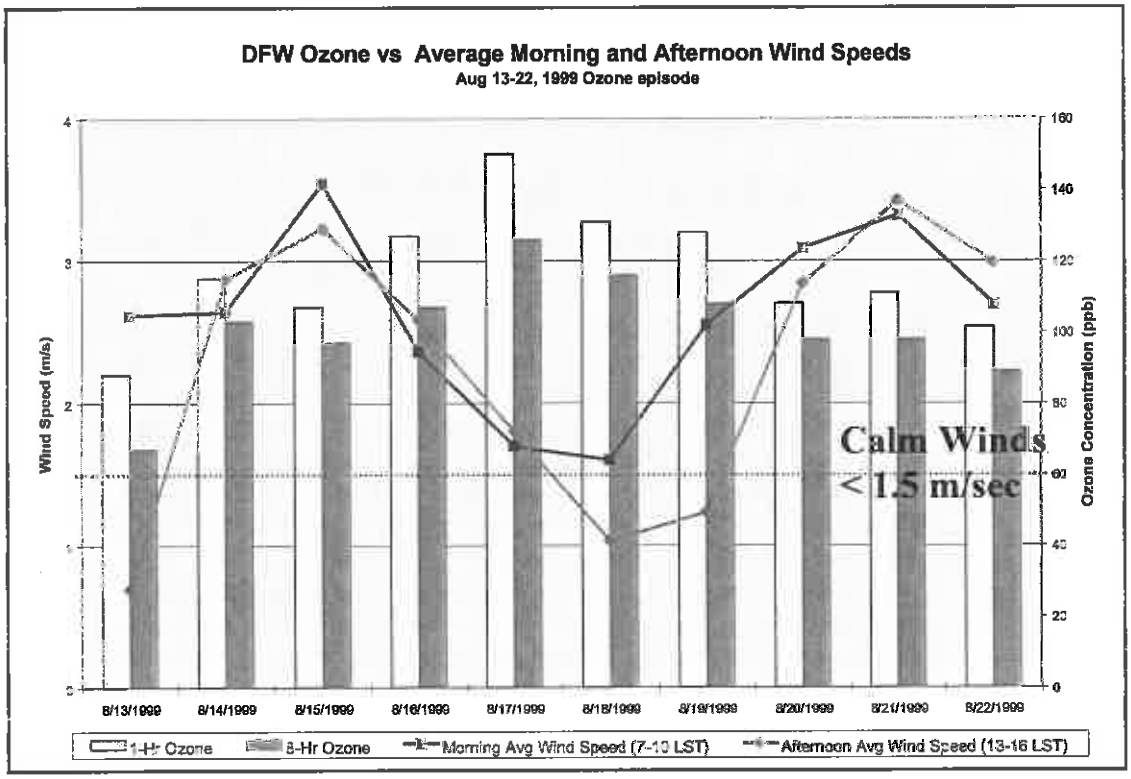


Figure 2-3: DFW Ozone vs. Morning and Afternoon Wind Speeds

- Episodes should include days that have high ozone concentrations in the geographical locations where high values typically occur. The Frisco, Denton, and Keller monitors

experienced multiple exceedances during the August 13-22, 1999, period and are on the north and west side of the DFW area, the areas that most frequently experience high ozone, as shown in Figure 2-4: *DFW Sites with High Eight-Hour Ozone Design Values.*

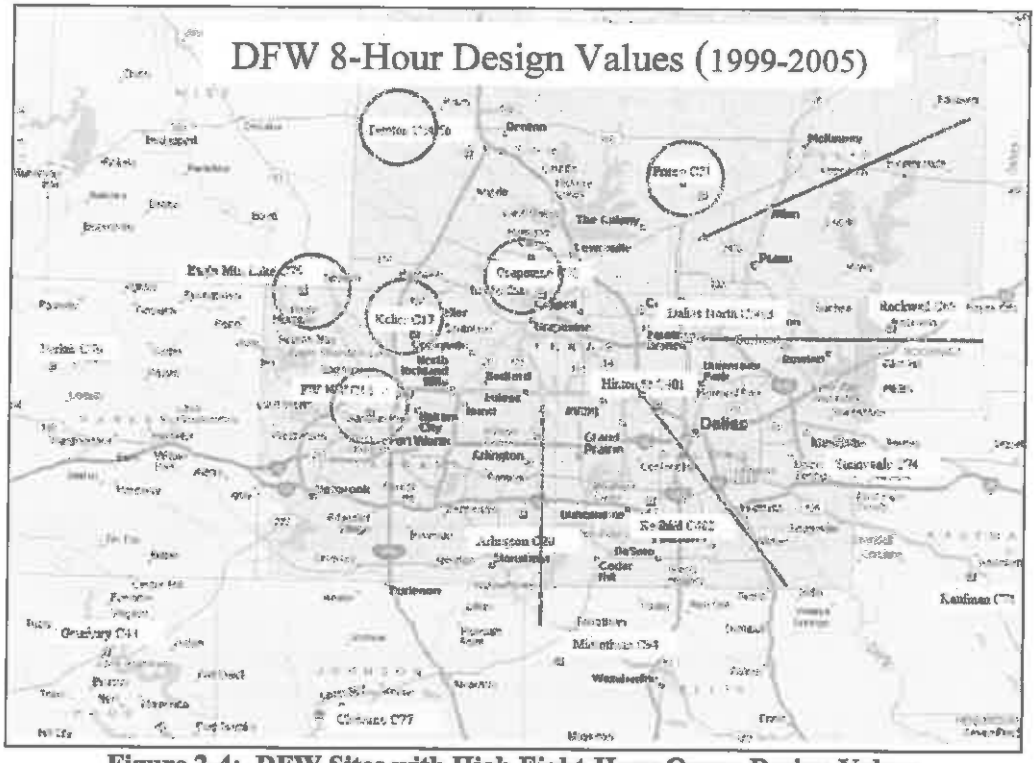


Figure 2-4: DFW Sites with High Eight-Hour Ozone Design Values

- Episodes should include days with monitored ozone concentrations within 10 ppb of the design value to represent the magnitude of ozone that must be controlled. There were 36 eight-hour ozone exceedances recorded during the August 13-22 period, and 22 of those measurements were within 10 ppb of the site specific design value.

- The August 13-22, 1999, period starts on a low ozone day, includes nine consecutive days with eight-hour ozone exceedances, with ozone concentrations declining at the end of the period.

- The highest monitored ozone occur on the days with lighter winds in the middle of the episode and at the Frisco and Denton monitors, which have the highest design values for the period, as illustrated by Figure 2-5: *August 13-22, 1999, Daily Max Ozone and Number of Stations with Exceedances.*

DFW 8-Hour Ozone Episode

August 13 - August 22, 1999

Day	Date	Max O3	Site Name	# Sites	Remarks
F	Aug 13	67	Frisco	0	SW Winds, Ramp Day
Sa	Aug 14	103	Arlington	4	NE Winds
Sun	Aug 15	97	Keller	6	East Winds
M	Aug 16	107	Keller	6	East Winds
T	Aug 17	125	Frisco, Denton	7	Light SE Winds
W	Aug 18	116	Frisco	4	Light South Winds
Th	Aug 19	108	Midlothian	2	Weak Front, N Winds
Fri	Aug 20	98	Midlothian	1	NE Winds
Sa	Aug 21	98	Arlington	5	East Winds
Sun	Aug 22	89	Denton	2	SE Winds
Mon	Aug 23	59	Denton	0	S Winds, Low Ozone

TCEQ/Breitenbach January 26, 2006

Figure 2-5: August 13-22, 1999, Daily Max Ozone and Number of Stations with Exceedances

As a result of these considerations, the August 13-22, 1999, ozone episode was selected for one-hour ozone modeling for the DFW area. Additional review of the event confirmed that the August 13-22, 1999, episode was also typical of eight-hour ozone episodes. On February 1, 2005, TCEQ staff met with EPA Office of Air Quality Planning and Standards (OAQPS) and Region 6 staff and jointly agreed that the August 13-22, 1999, episode provided an acceptable platform for eight-hour ozone SIP development.

Since that time, the TCEQ has revisited the conceptual model (Dallas/Fort Worth Nonattainment Area Ozone Conceptual Model, TCEQ, November 2005) and confirmed that the meteorological and geographical patterns that occurred in the 1999 episode are still occurring. Therefore, the August 13-22, 1999, episode is still valid and represents both typical and current ozone events in the DFW area.

Finally, the TCEQ also performed preliminary modeling of additional ozone episodes to see if the additional data would assist in the attainment demonstration. Coarse grid (12 km) modeling using data from the Oklahoma extension period (August 23-September 1, 1999) indicated that the model performance during the extended period was not as reliable as the existing DFW core episode and that the extra days would not change the model response in the DFW area. Similarly, analysis of DFW 12 km results during the Houston 2000 episode indicated that the Houston modeling did not perform as well in the DFW area as the DFW core episode. In both cases, the extra time and effort to bring the modeling up to performance standards would commit staff resources and delay the schedule without significant benefit. Therefore, the TCEQ decided to focus only on the DFW core episode.

The details of the evolution and gradual improvement in the performance of this episode may be reviewed by referring to the supplementary documents in the appendices and the bibliography.

2.3 MODEL SELECTION AND SETUP

This section discusses the most recent formulation of the model, including selection of the air quality model, the modeling domain, and the initial and boundary conditions. As the result of some exploratory work done by Environ (Tai, 2005a) several upgrades were incorporated into the modeling, including an expanded modeling domain, more vertical layers, better low level mixing, and enhanced boundary conditions. These changes improved model performance and were incorporated into the DFW modeling.

2.3.1 Selection of Air Quality Model

Guidance from the EPA requires that the air quality model selected must be scientifically appropriate for the intended application and be freely accessible to all stakeholders. The following three simple prerequisites were set for selecting the photochemical grid model to be used for SIP-related modeling. The model must:

- have a reasonably current, peer-reviewed, scientific formulation;
- be available at no or low cost to stakeholders; and
- not require the reformatting of available model inputs from earlier rounds of the study.

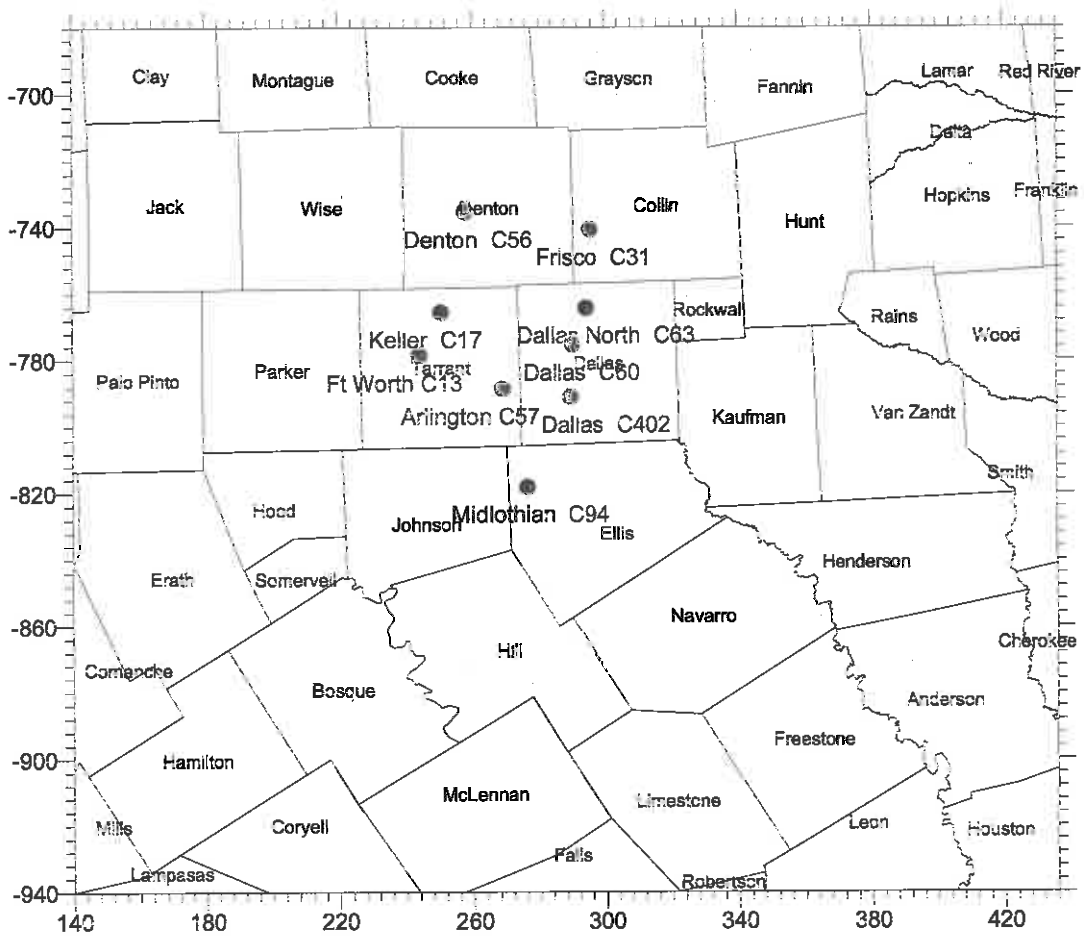
The only model to meet all three of these criteria is the Comprehensive Air Model with Extensions (CAMx). The model is based on well-established treatments of advection, diffusion, deposition, and chemistry. Another important feature is that NO_x emissions from large point sources can be treated with the plume-in-grid sub-model that helps avoid the artificial diffusion that occurs when point source emissions are inserted into a grid volume. The model software and the CAMx user's guide are publicly available at http://www.camx.com.

Version 4.03 of CAMx was used for all of the base case diagnostics and performance analysis and for the future case modeling for the majority of the sensitivity tests in order to maintain continuity and consistency with previous results. However, in June 2006 a new version of CAMx was tested to incorporate the latest upgrades and to be consistent with the Houston modeling. The new version (CAMx version 4.31) improves the plume dispersion algorithms and adds full NO_x and VOC chemistry in the plumes. CAMx 4.31 was tested in the base case and demonstrated improved performance, especially on August 17, the day with the highest monitored ozone concentrations. As a result of the improved base case performance in the DFW episode, CAMx 4.31 was used for the DFW future case modeling.

Similarly, the modeling emissions inventory underwent refinement over the course of the modeling analysis. The original emissions inventory, designated ".a0", was used for early modeling. The .a0 inventory was subsequently upgraded to the ".a1" inventory, which incorporated 2005 acid rain data for point source emissions. This .a1 inventory was then used for the future case sensitivity tests to maintain consistency and comparability. In June 2006, the final version of the emissions inventory, designated ".a2", was developed. This version of the inventory incorporated adjustments to the future case point source emissions for the Houston area cap and trade program and was used for all subsequent work.

2.3.2 Modeling Domain and Horizontal Grid Cell Size

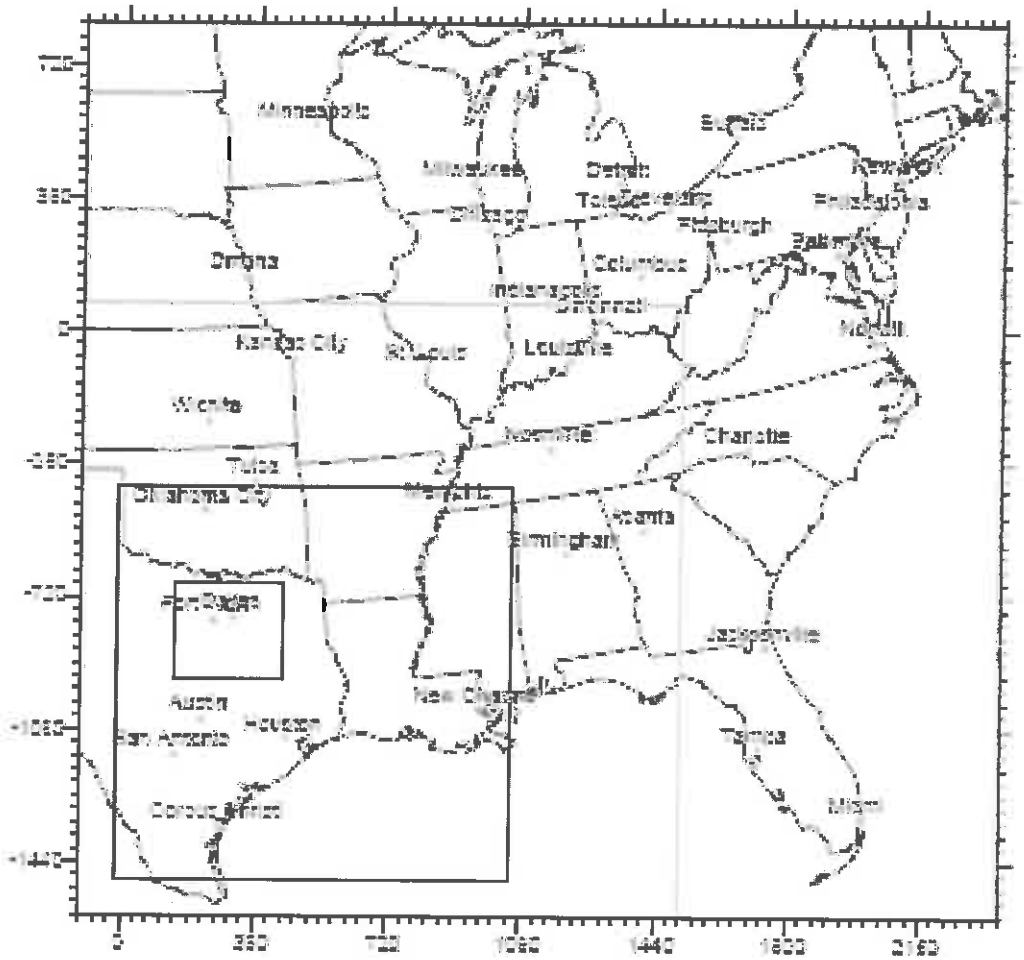
Early photochemical modeling for the DFW episode used the original DFW 36 km domain extending as far north as southern Nebraska and as far east as Georgia and the Florida Panhandle. The TCEQ expanded the modeling domain further east and north to reduce the influence of boundary conditions on ozone concentrations in the DFW area. The new domain expands the eastern boundary out to the Atlantic Ocean to include all of the eastern states and extends the northern boundary into North Dakota and part of Canada. The southern and western boundaries were unchanged.



CAMx Grid Dimensions
LCP center at (40 N, 100 W), True latitudes at 30 N and 60 N

4 km grid (with buffers): 74 x 65 from (140, -940) to (436, -680)
Figure 2-6: DFW Main Modeling Fine (4-km) Grid with Ozone Monitor Sites

Figure 2-6: *DFW Main Modeling Fine (4 km) Grid with Ozone Monitor Sites*, shows the DFW fine (4 x 4 km) grid used in all phases of the eight-hour ozone modeling of the August 1999 ozone episode. The grid shows the four core counties (Denton, Collin, Dallas, and Tarrant) as well as the surrounding five counties (Rockwall, Kaufman, Ellis, Johnson, and Parker) that were added as part of the eight-hour ozone standard nonattainment designation. The figure also shows the locations of the nine ozone monitors used in this modeling exercise.



CAMx Grid Definitions for DFW

	nx x ny	SW to NE Corners
CAMx 36km (standard)	45 x 48	(-102, -1584) to (1512, 72)
CAMx 36km expanded	69 x 67	(-108, -1624) to (2376, 528)
CAMx 12km	59 x 59*	(-12, -1488) to (1056, -420)
CAMx 04km	74 x 65*	(140, -840) to (436, -550)

* includes buffer cells

Figure 2-7: DFW Modeling Grids, Original Nesting and Expanded Grids (From Tai 2005a, Figure 4-1)

Figure 2-7: *DFW Modeling Grids, Original Nesting and Expanded Grids,* shows the original grid configuration as well as the extended domain used for the more recent modeling. The pink line shows the original smaller domain, and the blue lines show the current configuration. The expanded CAMx modeling domain consists of three nested grids depicted in blue. The finest grid (4 km × 4 km) encompasses the nine DFW nonattainment counties and is nested within a 12 km × 12 km grid covering the eastern part of Texas and extending into Louisiana and Mississippi. The outer 36 km × 36 km grid extends out to the Atlantic Ocean. The dimensions of the largest grid were selected based upon back trajectory analyses, which indicated that the expanded domain was large enough to minimize the impact of the contributions from the boundary conditions upon the 4 km inner grid while preserving reasonable model run times.

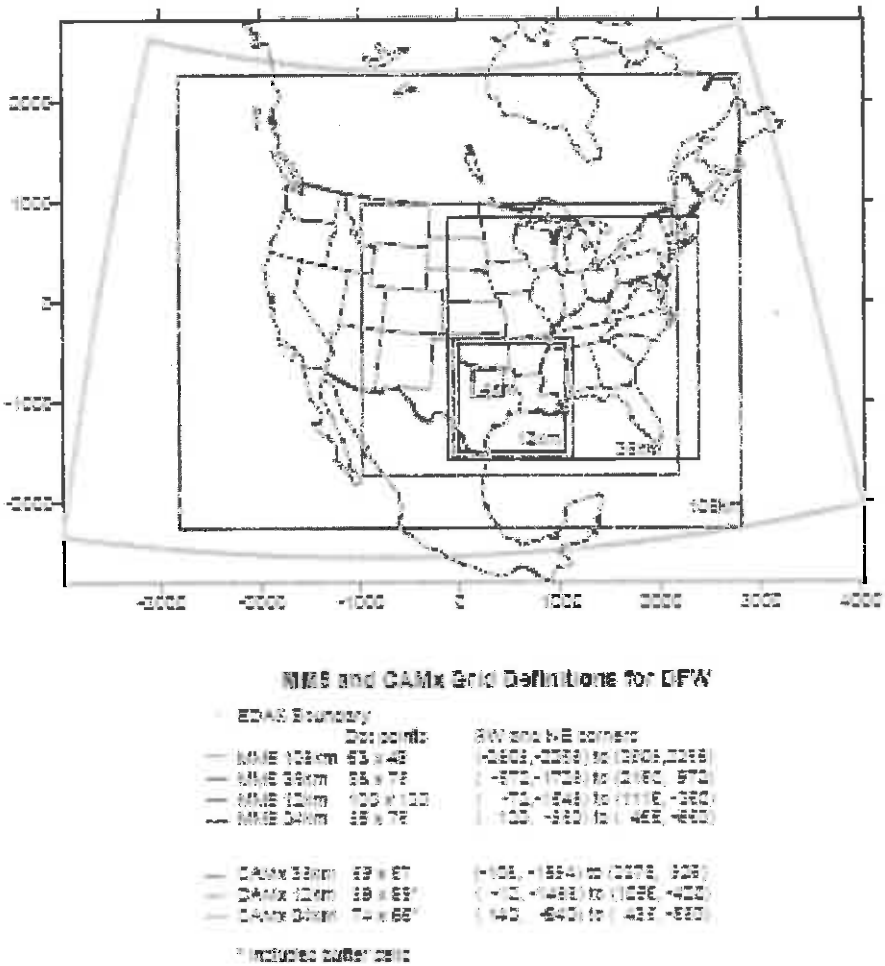


Figure 2-8: MM5 and CAMx Modeling Grids with the Expanded Domain (From Tai 2005a, Figure 4-2)

Figure 2-8: *MM5 and CAMx Modeling Grids with the Expanded Domain* shows both the NCAR/Penn State Mesoscale Model 5 (MM5) meteorological grid and the CAMx grids together. The meteorological grid is generally three cells larger than the CAMx grid, so that the interpolated meteorological conditions at the edge of each MM5 grid, which may not be balanced, are not used in the CAMx chemistry model.

2.3.3 Vertical Layer Structure

Determining the number of vertical layers for the modeling domain is a balance between including enough detail to accurately characterize the vertical layering of the atmosphere and managing the amount of computer time required to run the model. In the past, the first 15 vertical layers from MM5 and CAMx coincided, peaking at an altitude just below 4 km. Later work extended the model top to over 15 km by adding five additional layers, each spaced roughly 2 to 3 km apart.

The vertical layering structure from MM5 and CAMx is listed in Table 2-1: *MM5 and CAMx Vertical Layer Structure*. The layers are thinner near the surface and thicker at higher levels. The high level of vertical resolution in the lower layers helps the model to properly characterize the pollutant concentrations and the vertical gradients as the mixing depth changes throughout the day.

Table 2-1: MM5 and CAMx Vertical Layer Structure
(From Tai, 2005a. Table 4-1)

MM5 Layers	sigma	pressure	height	thickness	CAMx Layers	IC/BC
28	0.0000	50.00	18874.41	1706.76		
27	0.0250	73.75	17167.65	1362.47		
----------			Extended	CAMx Top	----------	
26	0.0500	97.50	**15805.17**	2133.42	--20---	^
25	0.1000	145.00	**13671.75**	1664.35	--19---	|
24	0.1500	192.50	12007.40	1376.75		|
23	0.2000	240.00	**10630.65**	1180.35	--18---	|
22	0.2500	287.50	9450.30	1036.79		|
21	0.3000	335.00	**8413.52**	926.8	--17---	|
20	0.3500	382.50	7486.72	839.57		|
19	0.4000	430.00	6647.15	768.53		Clean IC
18	0.4500	477.50	**5878.62**	709.45	--16---	|
17	0.5000	525.00	5169.17	659.47		|
16	0.5500	572.50	**4509.70**	616.58		|
----------			Original	CAMx Top	----------	|
15	0.6000	620.00	**3893.12**	579.34	--15---	|
14	0.6500	667.50	**3313.78**	546.67	--14---	|
13	0.7000	715.00	**2767.11**	517.77	--13---	|
12	0.7500	762.50	**2249.35**	491.99	--12---	
11	0.8000	810.00	**1757.36**	376.81	--11---	----------
10	0.8400	848.00	**1380.55**	273.6	--10---	^
9	0.8700	876.50	**1106.95**	266.37	---9---	|
8	0.9000	905.00	**840.58**	259.54	---8---	|
7	0.9300	933.50	**581.04**	169.41	---7---	|
6	0.9500	952.50	**411.63**	166.65	---6---	|
5	0.9700	971.50	**244.98**	82.31	---5---	Moderate IC
4	0.9800	981.00	**162.67**	65.38	---4---	|
3	0.9880	988.60	**97.29**	56.87	---3---	|
2	0.9950	995.25	**40.43**	20.23	---2---	↓
1	0.9975	997.62	**20.19**	20.19	---1---	
0	1.0000	1000.00	**0.00**	==========	Surface	==========

2.3.4 Initial and Boundary Conditions

ENVIRON developed the initial and boundary conditions for modeling conducted in the DFW and Northeast Texas areas. The EPA default concentrations were used for most species, but concentrations of several important ozone precursors, including isoprene and NO, were modified based on monitoring data collected at Kinterbish, Alabama, a rural site near the eastern border of the modeling domain. Additional details about boundary concentrations may be found in Mansell (2003), starting on page 6-23.

Boundary conditions are classified into three categories: clean, moderate, and dirty. The table in Figure 2-9: *Boundary Conditions Used for the Expanded Domain in DFW Modeling* shows the boundary concentrations associated with each category. Boundaries over the Gulf of Mexico and the Atlantic were assigned clean conditions. The western boundary, the southern boundary over Mexico, and the northern boundary over Nebraska were set to the moderate group up to 1700 m and clean farther aloft. The dirty category was used over land areas with the smaller domain but not used in the extended domain. Initial conditions were clean everywhere.

Species	Dirty	Moderate	Clean
O3	40	40	40
CO	200	200	100
NO	0.1	0.1	0.1
NO2	1	1	1
HNO3	3	3	1
HNO2	0.001	0.001	0.001
ALD2	0.555	0.555	0.05
ETH	0.51	0.51	0.15
HCHO	2.1	2.1	0.05
OLE	0.3	0.3	0.05
PAR	14.9	14.9	7.5
TOL	0.18	0.18	0.0723
XYL	0.0975	0.0975	0.0323
ISOP	3.6	0.1	0.001
PAN	0.1	0.1	0.1
H2O2	3	3	1
MEOH	2.6	0.001	0.001
ETOH	1.1	0.001	0.001

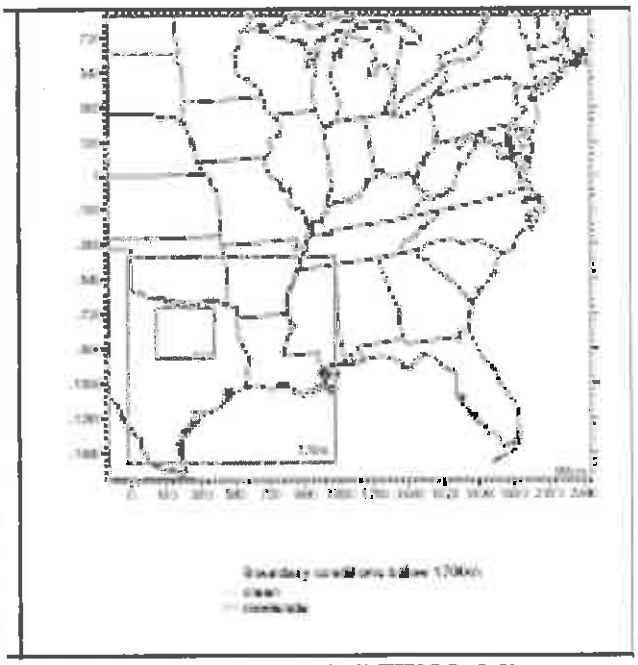


Figure 2-9: Boundary Conditions Used for the Expanded Domain in DFW Modeling

2.3.5 CAMx Model Options

CAMx has several user-selectable options that are specified for each simulation through the CAMx control file. Four model options must be decided for each project: the advection scheme, the plume-in-grid scheme, the chemical mechanism, and the chemistry solver. The selection for each option is decided during the base case model performance evaluation and then held fixed for the evaluation of any future year emission scenarios. The recommended choices for these options are discussed below. See the CAMx User's Guide (ENVIRON, 2000) for more details on these options.

Advection Scheme

CAMx version 4.02 has three optional methods for calculating horizontal advection (the movement of pollutants due to resolved horizontal winds). These are known as Smolarkiewicz, Bott, and the Piecewise Parabolic Method (PPM). The Smolarkiewicz scheme has been used for many years and was used in previous modeling for Northeast Texas (ENVIRON, 1999). The Smolarkiewicz scheme has been criticized for causing too much artificial diffusion of pollutants, tending to dilute features and artificially overstate transport. The Bott and PPM schemes are newer and have less artificial diffusion than the Smolarkiewicz scheme. The PPM scheme was used for this study because it was determined to be the least numerically diffusive; it runs at speeds similar to Smolarkiewicz; and it does not exhibit certain noisy features near sharp gradients that are apparent with the Bott approach.

Plume-in-Grid

CAMx includes an optional sub-grid scale plume model, which can be used to represent the dispersion and chemistry of major NO_x point source plumes close to the source. The TCEQ used the Plume-in-Grid (PiG) sub-model for major NO_x sources (i.e., point sources with episode-average NO_x emissions greater than two tons per day (tpd) in the 4-km grid).

Chemical Mechanism

CAMx provides two alternatives for the chemical mechanisms used to describe the gas-phase chemistry of ozone formation: the Carbon Bond 4 (CB4) and SAPRC99 mechanisms. The most

widely used mechanism for regional applications is CB4 with the updated isoprene and radical termination reactions. CB4 was used for this study.

Chemistry Solver
CAMx has two options for the numerical scheme used to solve the chemical mechanism. The first option is the Chemical Mechanism Compiler (CMC) fast solver, which has been used in every prior version of CAMx. The second option is an Implicit Explicit (IEH) solver. The CMC solver is faster and more accurate than most chemistry solvers used for ozone modeling. The IEH solver is even more accurate than the CMC solver, but slower. The CMC solver was used for this study.

2.4 METEOROLOGICAL MODELING

This section discusses the results of a series of studies designed to improve the meteorological modeling in support of the DFW August 13 - 22, 1999, ozone episode. The first meteorological modeling for this episode was done in 2003 (Mansell, 2003) in support of both one-hour and eight-hour ozone modeling requirements. That work used the following physics configuration:

- Simple-ice microphysics is employed for all domains;
- Kain-Fritsch cumulus parameterization scheme is invoked for 108 km, 36 km, and 12 km grids;
- No cumulus parameterization scheme is invoked for the 4 km domain, as convection is explicitly fully resolved at this resolution scale;
- The Rapid Radiative Transfer Model (RRTM) radiation scheme is used for all of the grids;
- Two-way interactive 108 km, 36 km, 12 km, and 4 km grids are used;
- The Pleim-Xiu Land Surface Model (LSM) with its own Planetary Boundary Layer (PBL) scheme; and
- 28 layers reaching up to 50 mb or 18,874 meters.

The early work was satisfactory but showed a general tendency to under predict ozone levels. The tendency to under predict was attributed to problems with high wind speed and wind direction errors that diluted ozone concentrations and carried the urban plume out of the DFW area. However, one CAMx sensitivity test also indicated that the CAMx model was not properly replicating the growth of the boundary layer and the afternoon maximum mixing height. Additional meteorological modeling was recommended to evaluate vertical mixing parameterization. Another CAMx sensitivity test indicated that ozone concentrations within the DFW area are particularly sensitive to the boundary conditions, highlighting the importance of setting the correct concentrations at the boundaries of the model. Due to these findings, the next round of modeling incorporated a larger modeling domain to allow the CAMx model to correct the boundary concentrations as they interact with emissions over a longer path before arriving in the DFW area.

Second Round
A second round of MM5 modeling (Emery, 2004) was designed to address the generalized ozone under prediction by reducing the wind speeds and directional errors. The project focused primarily on enhancing the performance of the previous meteorological modeling with the ultimate goal of improving ozone model performance. The meteorological improvements were validated using statistical comparisons to the data measured during the episode.

Three MM5 sensitivity tests were conducted to test the effect of increasing surface roughness, the model performance without nudging, and nudging toward a different large scale analysis without increased surface roughness. Neither of the latter two tests significantly improved performance but the increased surface roughness feature was used in subsequent runs. In a fourth run, additional observed meteorological data (DFW radar profiler data, Oklahoma Mesonet data, and Sonic Detection and Ranging (SODAR) data) were incorporated to improve the wind

performance. The fifth and final test run repeated this, except that the Environmental Data Assimilation System (EDAS) analyses were replaced with National Center for Environmental Prediction (NCEP)/National Center for Atmospheric Research (NCAR) Reanalysis Project (NNRP) analyses.

Follow-up tests with CAMx to compare the ozone generated with original meteorology and the different meteorological data fields did not significantly change CAMx model performance. Therefore, the choice of meteorological fields was reduced to determining which set of meteorology performed the best against the observed wind, temperature, and humidity data. The fifth run in this series of tests (Run 5 - with increased surface roughness, additional meteorological data, and NNRP analyses) was selected for future photochemical simulations.

Recent Upgrades

The next round of meteorological modeling was funded by the Houston Advanced Research Center (HARC) and reported in 2005 (Tai, 2005a). The goals of the HARC project were to improve ozone model performance for the August 13- 22, 1999, DFW episode and to investigate how changes in modeling inputs impact ozone formation. There were three components to this HARC project, but only the first component of the study discussed meteorology and is included in this section.

A key component of the HARC project sensitivity tests was to develop two alternative MM5 simulations and to investigate their impacts on CAMx performance. Statistical model performance was determined for the two alternative MM5 runs similarly to that reported by ENVIRON for the original MM5 configuration (Emery, 2004). For the purposes of this chapter, the original run will be called "Run 5," and the other simulations will be labeled "Run 6" and "Run 7," respectively. Run 6 replaces the Pleim-Xiu Land Surface Model (LSM)/Planetary Boundary Layer (PBL) schemes with Eta + Noah schemes. Run 7 replaces the Kain-Fritsch sub-grid cumulus convection scheme with the Grell scheme.

Several years ago, ENVIRON selected the Pleim-Xiu (P-X) LSM/PBL scheme for Texas MM5 modeling due to its improved performance for winds, temperature, and PBL depth over the original configuration (i.e., the simple 5-layer soil model with Gayno-Seaman and Medium Range Forecast model (MRF) PBL schemes). Recent MM5 modeling for DFW has indicated that PBL depths remain much too high using P-X, as indicated by comparison to real data. The TCEQ selected the Eta PBL scheme along with the Noah LSM, which is the only alternative soil model available that has technical capabilities on par with the P-X methodology.

Daily performance statistics for these runs are shown below in Figures 2-10: *Daily Site-Averaged MM5 Wind Performance for Runs 5, 6, and 7 in the DFW 4 km Modeling Domain,* 2-11: *Daily Site-Averaged MM5 Temperature Performance for Runs 5, 6, and 7 in DFW 4 km Modeling Domain,* and 2-12: *Daily Site-Averaged MM5 Humidity Performance for Runs 5, 6, and 7 in DFW 4 km Modeling Domain.* As expected, results from Run 5 and Run 7 are comparable for wind, temperature, and moisture. Both runs show slight over estimation of wind speed during most of the episode days, a relatively high warm bias for the daytime temperature, and a low humidity bias.

In Run 6, however, the over prediction of wind speed is reduced, and wind speed is biased low rather than high. The picture is not as clear with wind direction except that the gross error (total error) is comparable in all three runs. In Run 6 the temperatures run high since the heat is trapped in a shallower mixed layer, but the reduced mixing also improves the underestimation of moisture in Run 5 and 7. As a result of these tests and the importance of reducing wind speeds, Run 6 with the Eta/Noah PBL was selected for use in the DFW attainment demonstration modeling.

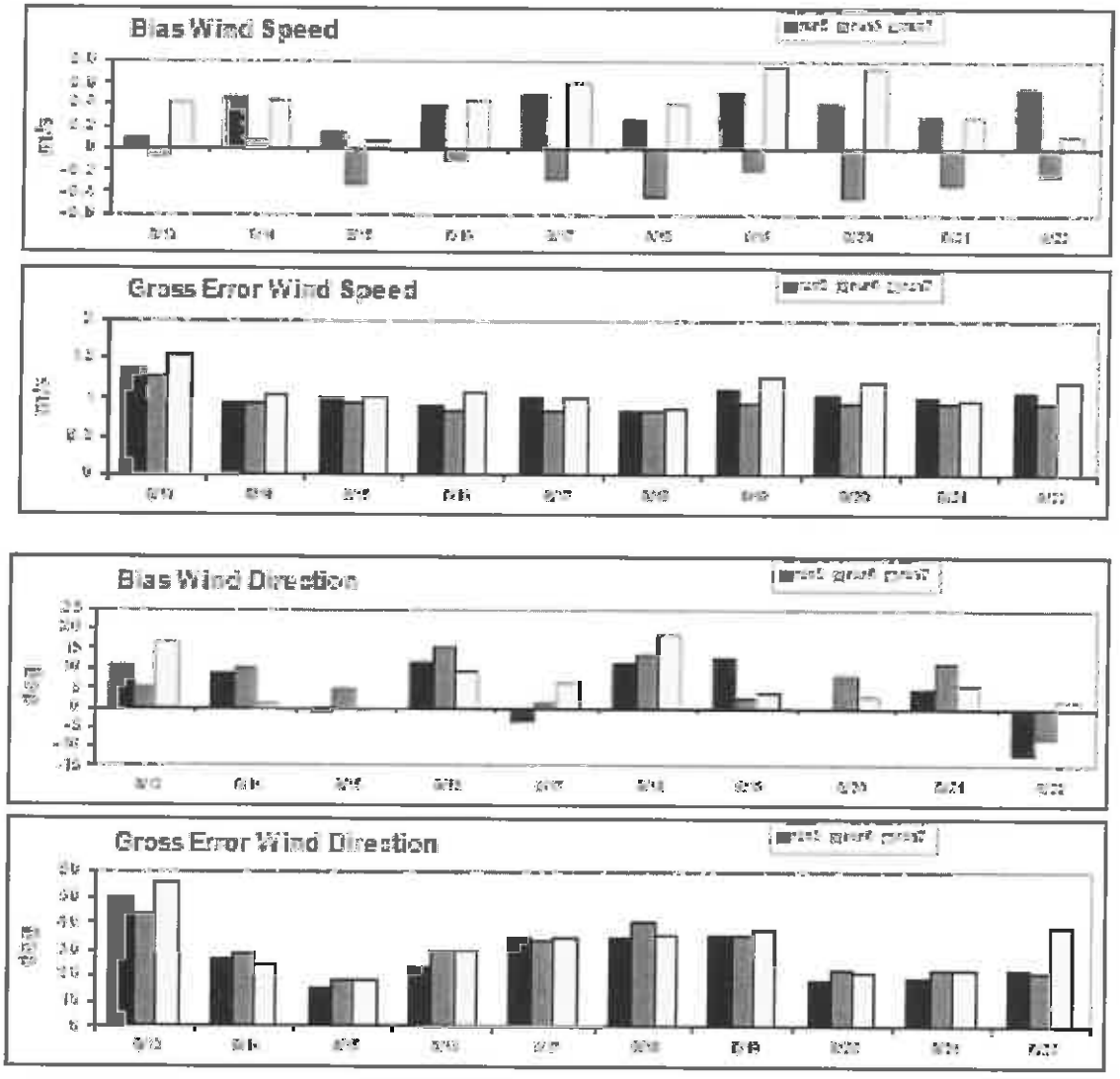


Figure 2-10: Daily Site-Averaged MM5 Wind Performance for Runs 5, 6, and 7 in the DFW 4 km Modeling Domain. Chart from Tai, 2005a, Figure 2-2(a)

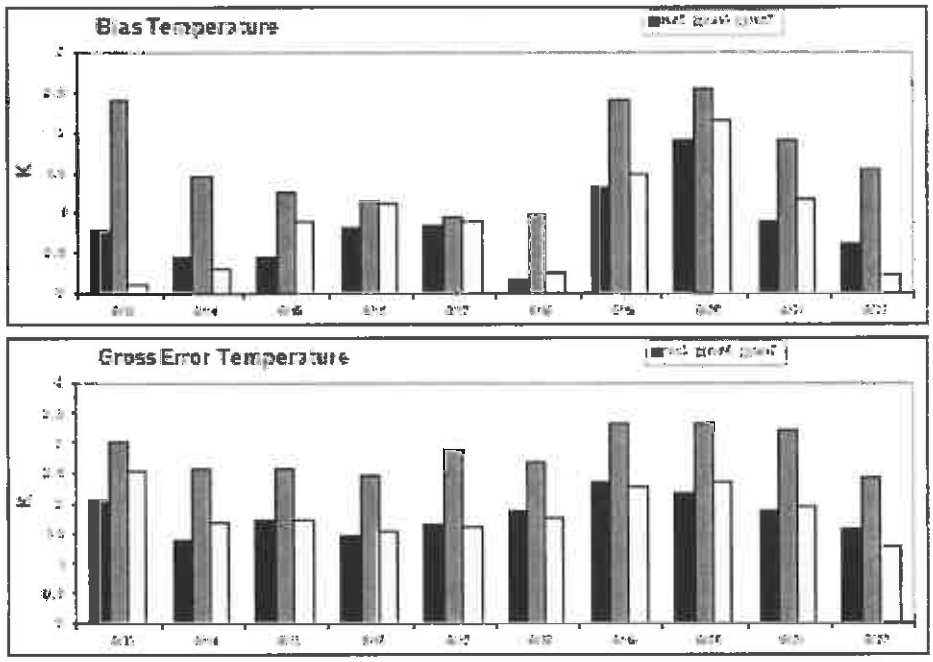


Figure 2-11: Daily Site-Averaged MM5 Temperature Performance for Runs 5, 6, and 7 in the DFW 4 km Modeling Domain

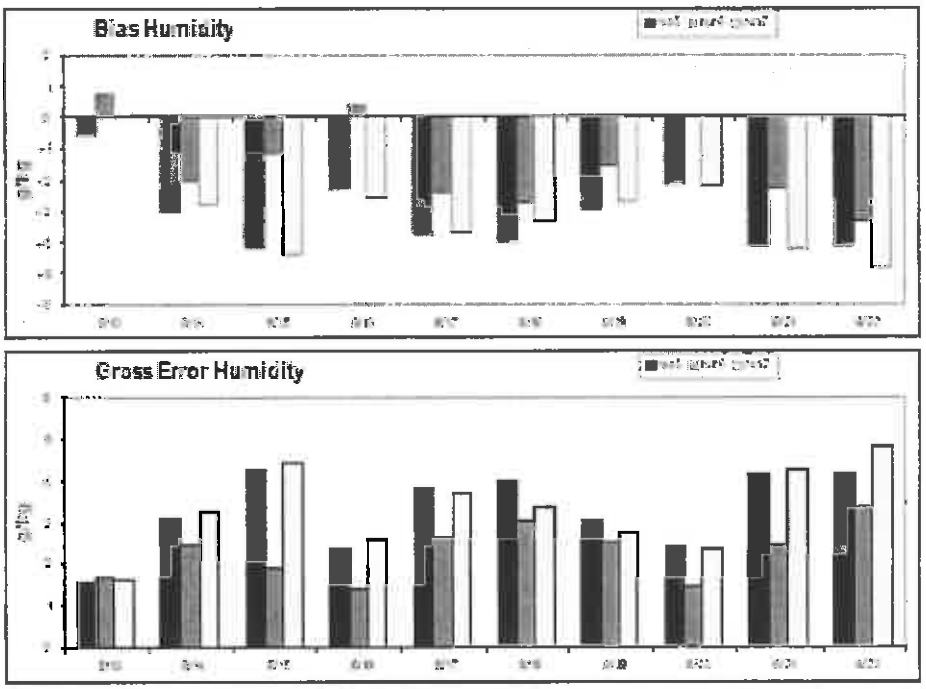


Figure 2-12: Daily Site-Averaged MM5 Humidity Performance for Runs 5, 6, and 7 in the DFW 4 km Modeling Domain

Comparisons between the observed and modeled vertical profiles also indicate vertical mixing problems with the Pleim-Xiu PBL scheme. The Pleim-Xiu method (Runs 5 and 7) develops relatively deep and uniform mixing all over the domain, whereas the Eta-Noah (Run 6) scheme develops variable mixing heights that are both lower and more realistic. The Eta-Noah scheme also predicted the vertical profiles for temperature and moisture, as well as the evening mixing height at the Fort Worth rawinsonde, better than the other two PBL schemes.

Ozone modeling results suggested that low level mixing problems might be the cause of low ozone production in the urban core. In particular, the modeled VOC and NO_x concentrations were higher than the measured values at the Hinton monitor, while the VOC/NO_x ratio was approximately correct. The mixing in the lowest layers of the model appeared too weak, trapping the emissions in the lowest layers of the model. The "Kv100" vertical mixing adjustment was applied in post-processing, which increased the mixing in the first three layers to match the mixing at 100 meters. The "Kv100" adjustment improved ozone predictions in the urban core by producing more ozone in areas with strong NO_x emissions that had previously experienced low ozone production.

Overall, Run 6 resulted in better vertical wind speed, temperature, and humidity profiles with lower bias for most of the time periods examined. Hence, Run 6 meteorology and the "Kv100" adjustment were used in all later CAMx modeling.

2.5 EMISSIONS INVENTORY

The photochemical modeling process requires four emissions inventories:

- the *base case inventory*,
- the *baseline inventory*,
- the *future-year inventory*, and
- the *future-year control strategy inventory*.

Base Case Inventory

The purpose of the base case emissions inventory is to validate both the meteorology and the emissions development procedures. Once the emissions and meteorology are generated, they are used in CAMx to model ozone concentrations during the episode. Model performance analyses are then conducted as described in the EPA modeling guidance (EPA 1999 and 2005). If the base case model performance is acceptable (correct concentrations, timing, and locations for every day of the episode), then the meteorology and emissions development procedures are considered to be sufficiently representative of the episode. Once the base case is accepted, the meteorology data are held constant through the next three phases of emission inventory development. The base case inventory for a typical episode day is summarized in Appendix A: *Emissions Inventories Used in Episode Modeling*.

Baseline Inventory

The EPA's procedures require the development of an RRF to calculate future ozone concentrations. Future-year emissions are projected based upon the base case year's emissions. However, the base case emissions can include day-specific and hourly emissions data. In order to keep the base and future case results used in the RRF comparable, a generic baseline emissions inventory is developed using the same averaging and estimating procedures that will be used in the future case. This baseline inventory is used with the base case meteorology to calculate the ozone concentrations that would occur with a generalized emission inventory. The baseline inventory for a typical episode day is summarized Appendix A: *Emissions Inventories Used in Episode Modeling*.

Future-Year Inventory

Emissions for the future-year inventory are generated by applying the projection growth estimates and controls that will be in effect in the future year to the baseline inventory. This projection provides the future base inventory, as opposed to the future controlled inventory discussed next. The same averaging procedures are used in both the baseline and future-year inventory to maintain comparability between the baseline and future-year ozone. The future-year inventory for a typical episode day is summarized in Appendix A: *Emissions Inventories Used in Episode Modeling*.

Future-Year Control Strategy Inventory
A future-year control strategy inventory (the future-year inventory with adopted control strategies applied) is required to determine the effectiveness of additional controls on modeled ozone concentrations. In this situation, a future-year emissions inventory with additional emissions reductions is generated. Control estimates are incorporated into the future-year emissions inventory, and the CAMx model is run to determine the effectiveness of the control strategies. The future-year control strategy inventory for a typical episode day is summarized in Appendix A: *Emissions Inventories Used in Episode* Modeling.

2.6 1999 BASE CASE, BASELINE, AND MODEL PERFORMANCE EVALUATION

Overview
The purpose of the base case is to develop the best possible meteorological and emissions inputs and procedures before moving on to forecasting the future case ozone. As described in previous sections, the emissions inventory and the meteorological inputs are generated on a day- and hour-specific basis and should match the real meteorology and emissions as closely as possible. Once the emissions and meteorology are generated, they are used as input to the photochemical model and the ozone generated each day and hour during the episode period is determined. The model results are then compared to the real-world ozone measurements at each monitoring site in the area using a package of graphical evaluations and statistical benchmarks established by the EPA (EPA, 1999 and 2005). If the base case modeled ozone reproduces the measured ozone concentrations, timing, and locations within acceptable criteria specified in the EPA's guidance, both the meteorology and emissions development procedures are sufficiently representative to move to the future case.

In its 2005 eight-hour ozone modeling guidance, the EPA indicates that air quality model performance can be evaluated with two types of tests: 1) Operational tests - How well does the model replicate observed concentrations of ozone and precursors, and 2) Diagnostic tests - How well does the model respond to changes in emissions? The EPA recommends a suite of statistical tests and graphical tests for the operational evaluation that is based upon measured data. The EPA also encourages the use of diagnostic tests, but since diagnostic tests are more subjective, they are more difficult to quantify. Finally, the EPA acknowledges that there is no single definitive test or criterion for evaluating model performance.

Background
The TCEQ began working on the August 13-22, 1999, DFW ozone episode before the EPA eight-hour ozone modeling guidance was finalized. Initially, work on this episode began in support of the one-hour ozone standard and the DFW one-hour ozone MCR. Over time, the negative bias (indicative of low ozone production) has been addressed, and the model performance has been significantly improved. Previous work regarding the August 13-22, 1999, DFW ozone episode, which was approved by the EPA, is listed in the bibliography (Environ, 2003; Mansell, 2003; Emery, 2004 and Environ, 2004, located on the web at: http://www.tceq.state.tx.us/implementation/air/airmod/data/dfw1.html). This section will discuss model improvements, starting with Run 20, focused on the 1999 base case and baseline performance, and a comparison of the model output data against the inventoried precursor concentrations and measured ozone.

A HARC project (Tai, 2005a) improved ozone model performance for the August 13-22, 1999, DFW SIP episode and investigated how various updated modeling assumptions impacted ozone formation. There were five components to the work:

- ten CAMx sensitivity runs were completed to investigate how changes in modeling inputs and assumptions affect ozone model performance;
- two MM5 runs were completed to support the CAMx sensitivity analysis;
- a revised 1999 base case (CAMx Run 34) was developed from the sensitivity tests;

- process analysis was used to investigate the revised 1999 base case and two related model scenarios; and
- the Anthropogenic Precursor Culpability Analysis (APCA) technique was used to investigate the effect of several modeling assumptions on ozone transport for 2010 future year scenarios.

After each group of tests, performance was assessed, and the best combination of factors incorporated into subsequent modeling. As a result of this series of sensitivity tests, eight-hour ozone model performance was further improved as demonstrated in Figure 2-13: *Bias and Gross Error Plotted in Error Space for Eight-Hour Ozone CAMx Modeling Runs*. Run 23 continues to show a strong negative bias, but Run 34 is inside the box on all, except ramp up days. The Run 46 cluster has only one ramp up day outside of the box and sits lower in the 'V' indicating even less total error than any of the other runs. Run 46 is the final 1999 baseline run and provides the basis for future work on the attainment demonstration.

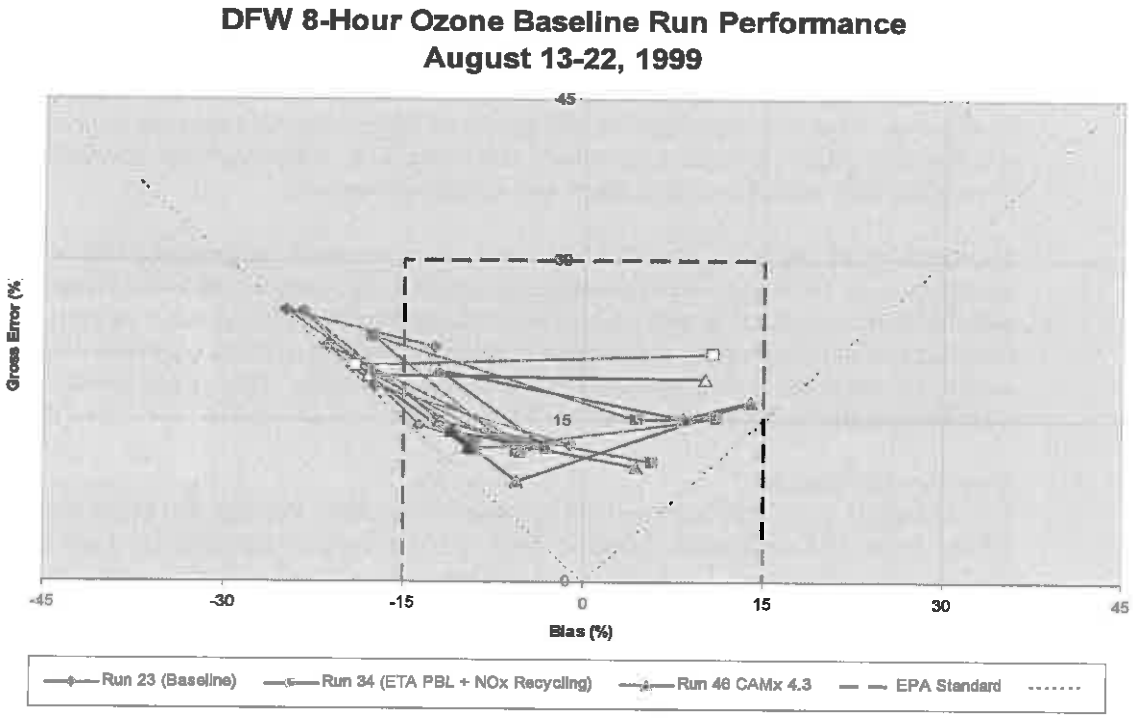


Figure 2-13: Bias and Gross Error Plotted in Error Space for Eight-Hour Ozone CAMx Modeling Runs

Improving Model Performance

The HARC project to improve model performance (Tai, 2005a) started from the CAMx base case that was developed for the DFW August 13-22, 1999, episode referred to as Run 17b (Emery et al., 2004). Ten modifications were applied separately to understand how model performance changed for both one-hour and eight-hour ozone, and how model performance might be improved. Sensitivity tests included changes in the size and top of the modeling domain, meteorology, emissions, and chemistry. All runs used CAMx version 4.03 and started from model inputs for the August 13-22, 1999, episode described by Emery et al. (2004).

Domain Modifications

Two of the modifications examined expanding the modeling domain. One test expanded the horizontal domain eastward into the Atlantic Ocean and northward into parts of Canada, yielding slightly improved model performance. The second modification extended the model top from 4

km to 14 km and also resulted in minor improvements in ozone performance. When both assumptions were applied, model performance improved even more. These modifications were judged to be improvements because they improved model performance and reduced dependence on boundary condition (BC) assumptions. As a result, all remaining sensitivity tests used the expanded horizontal domain and the higher model top.

Alternative Meteorology
As discussed in Section 2.4, *Meteorological Modeling*, ozone sensitivity to different CAMx meteorological input data was also examined. Overall, Run 24 (including MM5 Run 6) was judged to give superior meteorological and air quality model performance, so it was selected and carried forward into subsequent work.

Emission Modifications
Sensitivity tests were also conducted to evaluate model response to changes in the emissions. Ozone model performance in the DFW 4-km domain improved when the mobile source NO_x emissions were reduced by 30 percent inside the four DFW core counties. This result may be due to intense surface NO_x emissions in the DFW core area inhibiting ozone formation immediately downwind of the core where high ozone levels are observed. The peak ozone on August 17th was increased and shifted eastward closer to the observed peak location. Increasing biogenic emissions by 30 percent domain-wide also produced higher daytime ozone but did not systematically improve model performance. Doubling VOC emissions from non-EGF point sources had little impact on ozone levels and model performance.

The results of the sensitivity test showing improved ozone model performance with lower NO_x emissions in the DFW core were not sufficient to justify changing the emission inventory. Ozone model performance in DFW also is sensitive to changes in meteorology and chemistry. However, comparing modeled precursor concentrations to monitored concentrations indicated that the vertical mixing in the lowest layers of the model was inadequate. Changes to vertical mixing were incorporated in Runs 34 and 46.

Chemistry Mechanisms
Two additional chemical mechanism changes were evaluated. The first test evaluated a revised version of the CB4 mechanism called CB2002. CB2002 reduced ozone levels relative to the standard CB4 mechanism, degraded model performance, and was not implemented further. The second test, called CB4xi, extended the CB4 mechanism by adding 17 inorganic chemistry reactions. The most important of the extra inorganic reactions in CB4xi are several NO_x recycling reactions, which bring some of the NO_x from terminal reactions back into the model chemistry. For short model runs, NO_x recycling is negligible. However, for extended episodes and long transport paths, some of the NO_x should be recycled. When the NO_x recycling reactions were added to CB4, ozone concentrations were increased regionally by a few ppb both in the daytime and at night.

Conclusions from the Sensitivity Tests
The sensitivity tests improved model performance and better replicated monitored values by:

- increasing NO_x in the DFW core counties;
- adding more biogenic emissions; and
- implementing the NO_x recycling reactions in CB4.

These runs generally improved the normalized bias, the gross error and average paired peak accuracy, but reduced the accuracy of the unpaired peak. However, the unpaired peak accuracy is an old one-hour ozone test that evaluates the difference between two numbers: the maximum monitored ozone and the maximum modeled ozone. Since these two maxima are not matched in either time or space, the test only indicates whether the model is generating enough one-hour ozone somewhere in the domain. The unpaired peak test is not relevant in eight-hour ozone modeling since the focus is no longer on the one-hour worst-case modeled ozone peak, but

instead on the relative reduction in the eight-hour ozone generated at each monitor. The use of the CMAQ-based vertical diffusivity profiles and the CB2002 chemical mechanism lowered ozone, which did not improve model performance. Therefore, these options were not pursued further.

Revised Base Case: Run 34

As a result of these sensitivity tests and the improvements in model performance, a revised base case was developed for the DFW August 13-22, 1999, SIP episode referred to as Run 34. Changes in Run 34 compared to the previous Run 17b base case include:

- expanded modeling domain extending to the Atlantic Ocean and Canada;
- higher model top at about 14 km;
- meteorology from MM5 Run 6 using the Noah/Eta PBL scheme;
- enhanced near surface mixing from the Kv100 adjustment; and
- extended inorganic chemistry (CB4xi) with NO_x recycling reactions.

Run 34 shows improved ozone model performance compared to Run 17b. A tendency toward ozone under-prediction (negative bias) was improved by the updated meteorology "MM5 Run 6" and the chemistry updates (NO_x recycling). The "Kv100" adjustment increased vertical mixing and improved the ozone predictions in areas with intense surface NO_x emissions in the DFW core area.

The modeling grid was expanded as the result of several sensitivity tests (Tai, 2005a) that indicated the expansion of the modeling domain eastward and northward, as well as a higher model top, produced slightly improved model performance with less dependence upon boundary condition assumptions. Using the larger domain, additional sensitivity tests were run to evaluate the ozone response to changes in the emissions, meteorology, and chemistry. As previously discussed in the conclusions portion, these tests demonstrated that reducing excess NO_x in the four core counties, adding more biogenic emissions, and implementing the NO_x recycling reactions in CB4 consistently produced higher ozone and improved model performance, especially on the critical high ozone days.

On most days, these runs improved the normalized bias statistic and reduced the gross error statistics, which measures total error in the system. The test runs also improved the average accuracy of the paired peak statistic, which reflects the average peak ozone generated at all the sites in the domain.

Supplemental Modeling Analysis

Other supplementary tests were also run to address the evolving changes in the EPA's draft guidance. The EPA's latest draft of eight-hour ozone modeling guidance (EPA, 2005a) suggests that states should model an extended period that includes a complete synoptic cycle of ozone buildup through peak and decay. The DFW core episode period includes a complete synoptic cycle, but there also were additional high ozone days in late August 1999 after the core episode period that had been previously modeled for Oklahoma. This SIP evaluates the supplemental period from August 23 – September 1, 1999, as well as the TexAQS 2000 episode (August 22 through September 6, 2000) to evaluate the benefit of adding more high ozone days to the calculations.

Oklahoma Extension

Modeling results for the Oklahoma supplemental period were intended to be used to corroborate the primary results obtained for the core episode (August 13-22, 1999). This study used the same Run 34 CAMx configuration found to yield the best model performance in the previous work (Tai 2005a). Oklahoma emissions (Tai, 2005b) were available for the supplemental period, but detailed Texas emissions were not. Texas emissions for the supplemental period were linked on a day-of-the-week basis to the Texas emissions in the core period. The supplemental period results are considered less reliable than the core period results because they were modeled on a coarser

grid with a less detailed emissions inventory. The meteorological performance for the supplemental period was also worse than the performance during the core period with under predicted (low) wind speeds and over predicted (high) temperatures.

In the supplemental period, Run 40 under predicted daytime ozone levels on August 25 and 26 at most monitoring stations. Run 40 vastly over predicted the ozone on August 31 and September 1 at the three most northern stations – Frisco (CAMS 31) and Denton (CAMS 56 and Colony). On one day, August 25, the supplemental modeling placed the peak ozone east of DFW, when the highest observed ozone was in Tarrant and Denton Counties. The poor ozone performance in the supplemental period is primarily related to the poor meteorological model performance discussed previously. In general, the supplementary episode was biased low and did not perform as well as the core episode. Review of the data indicated that the model results would not be as reliable as results from the core episode. Since considerable work would be required to bring the level of performance up to that of the core episode, further effort on this episode was terminated.

Texas Air Quality Study (TexAQS) 2000 Episode
The TCEQ also considered using the TexAQS 2000 modeling (for the Houston area) to generate more days for the EPA statistical test. The meteorology and the emissions were taken directly from the Houston work, but performance was evaluated in the 12 km grid in the DFW area. The TexAQS modeling performed poorly in the DFW area. The eight-hour ozone concentrations in the DFW area were biased consistently low on 14 of the 16 days during the episode, every day except the last two. A regression line through the scatter plot indicated that the ozone production was roughly one-half of the observed values, and the correlation coefficient (r2) was only 0.226. Since performance on this supplementary episode was not as good as performance during the DFW core episode and therefore would not be as reliable, further effort on this episode was also terminated.

Final 1999 Base and Baseline Cases (Run 46)
As a result of the series of previous base case sensitivity tests, base case modeling was temporarily frozen and further modeling efforts were redirected to evaluate the 2009 future case, and the model response to a series of sensitivity tests. While these sensitivity tests were being done, all of the future case emissions inputs were frozen to keep the results comparable. However, also during this period, the 2009 future emissions inventory was upgraded, and a newer version of CAMx became available. Once the sensitivity test series was complete, and the emissions upgrades were finalized, the base case was reevaluated with the new version of CAMx. Based on the improvement in base case model performance, all of the changes were made at once, updating to the newer version of CAMx as well as the updated inventory and several other minor changes.

The 1999 base and baseline cases with the new version of CAMx were then re-validated, so that the RRFs would be based on similar assumptions. The final base line model configurations for Run 34 and Run 46 are documented in Table 2-2: *1999 Baseline Model Inputs*.

Table 2-2: 1999 Baseline Model Inputs

Model Input	Run 34 Configuration	Run 46 Configuration
CAMx Version	CAMx 4.03	CAMx 4.31
Plume in Grid Treatment	-----	Full VOC/NO_x Chemistry
Domain	Expanded Domain	No Change
Model Top	High Top (14 km)	No Change
Meteorology	MM5 Run 6 Using Noah/ETA PBL	No Change
MM5 to CAMx Extraction	-----	Updated mm5-camx version includes cloud/rain inputs
Vertical Mixing Adjustment	Kv100 post processing Increases low level mixing	Kv 100 Patch
Base Case Emissions	TCEQ Base/NEI Ver 2	NEI Ver 3 Updated Mobile + Offshore
Chemistry	CB4xi w/NO_x Recycling	No Change

The most significant changes in model configuration were the CAMx upgrade from version 4.03 to version 4.31. CAMx version 4.2 had already included an upgraded plume-in-grid module to improve plume dispersion as well as full VOC and NO_x chemistry. CAMx version 4.3 incorporated a more sophisticated second-order closure puff spread calculation that operates at sub-grid scales (Environ 2006).

Model Performance

Tests were run to compare the results of three different CAMx versions. Run 44 used CAMx 4.03; Run 46 used CAMx 4.31; and Run 50 used CAMx 4.4, a beta version. The beta version (4.40) increased the bias and gross error and was not selected. CAMX 4.31 performed better than both 4.03 and 4.40 and was selected for future case modeling. A full package of eight-hour performance statistics, time series, and tile plots showing the spatial distribution of ozone each day are included as Figure 2-14: *Base Case Model Performance Statistics for Eight-Hour Ozone in DFW*, Figure 2-15: *Hourly Time Series for the 1999 Baseline Comparing Three Versions of CAMx,* and Appendix C: *Spatial Plots of the Daily Maximum 8-hour Ozone in the DFW 4 km Domain Using Three Versions of CAMx for Each Episode Day.*

For a list of all of the base case and baseline sensitivity tests to date, please refer to Appendix E: *1999 Base Case/Baseline Run Log.*

Conclusion

As previously discussed and demonstrated in Figure 2-13: *Bias and Gross Error Plotted in Error Space for Eight-Hour ozone CAMx*, Run 46 (using CAMx 4.31) develops more ozone than the previous runs and thus improves performance with essentially the same meteorology and base case emissions inventory. The increased ozone production over the entire domain has almost completely removed the persistent negative bias that was present in previous model runs, as well as reduced the total error in the modeling system. Since the purpose of the base case and baseline modeling is to optimize model performance and thereby to increase confidence in the future case results, Run 44 is the best foundation for future case work and control strategy testing. From this point forward, the Run 44 configuration was used for all future case modeling.

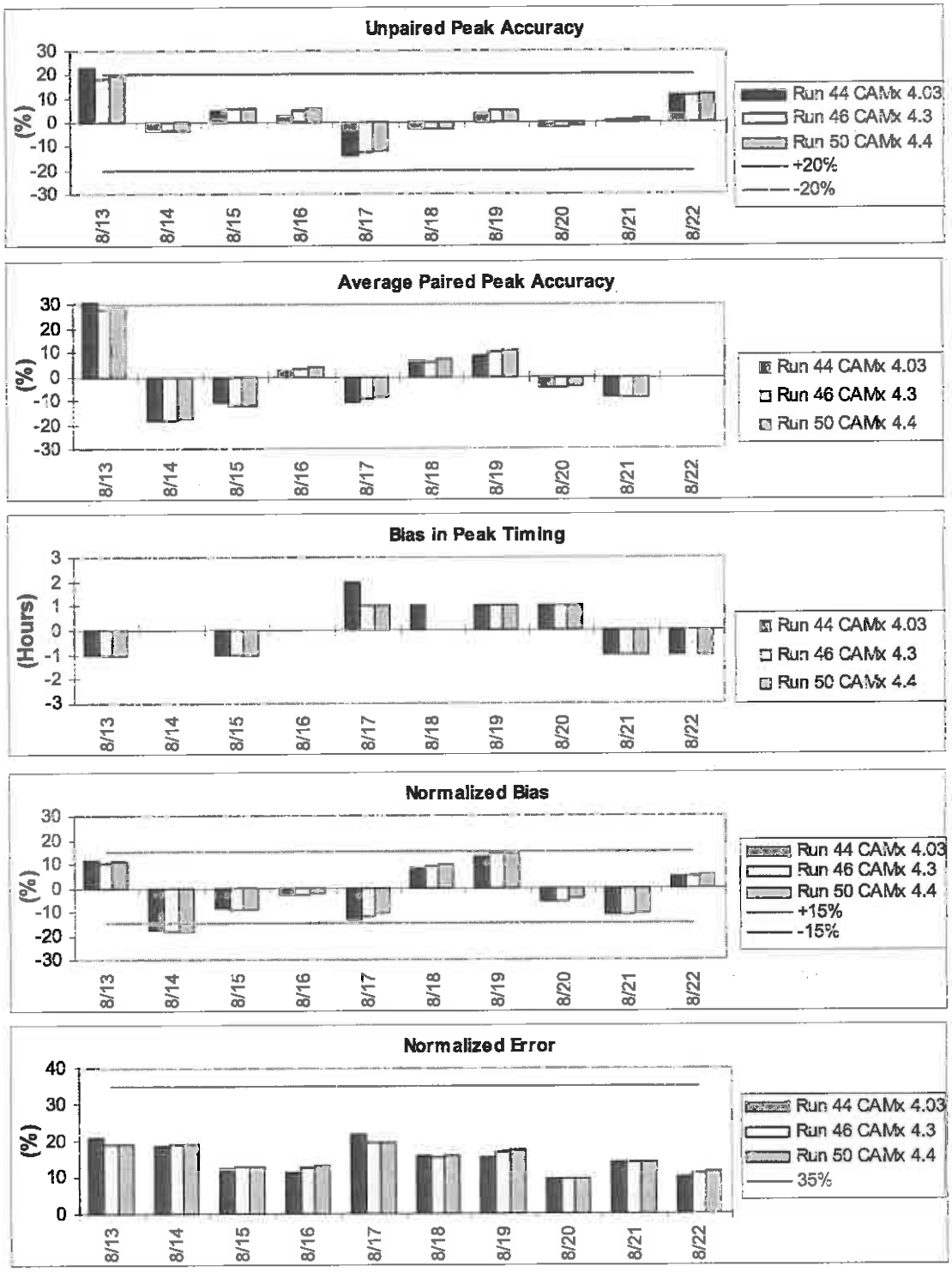


Figure 2-14: Base Case Model Performance Statistics for Eight-Hour Ozone in DFW

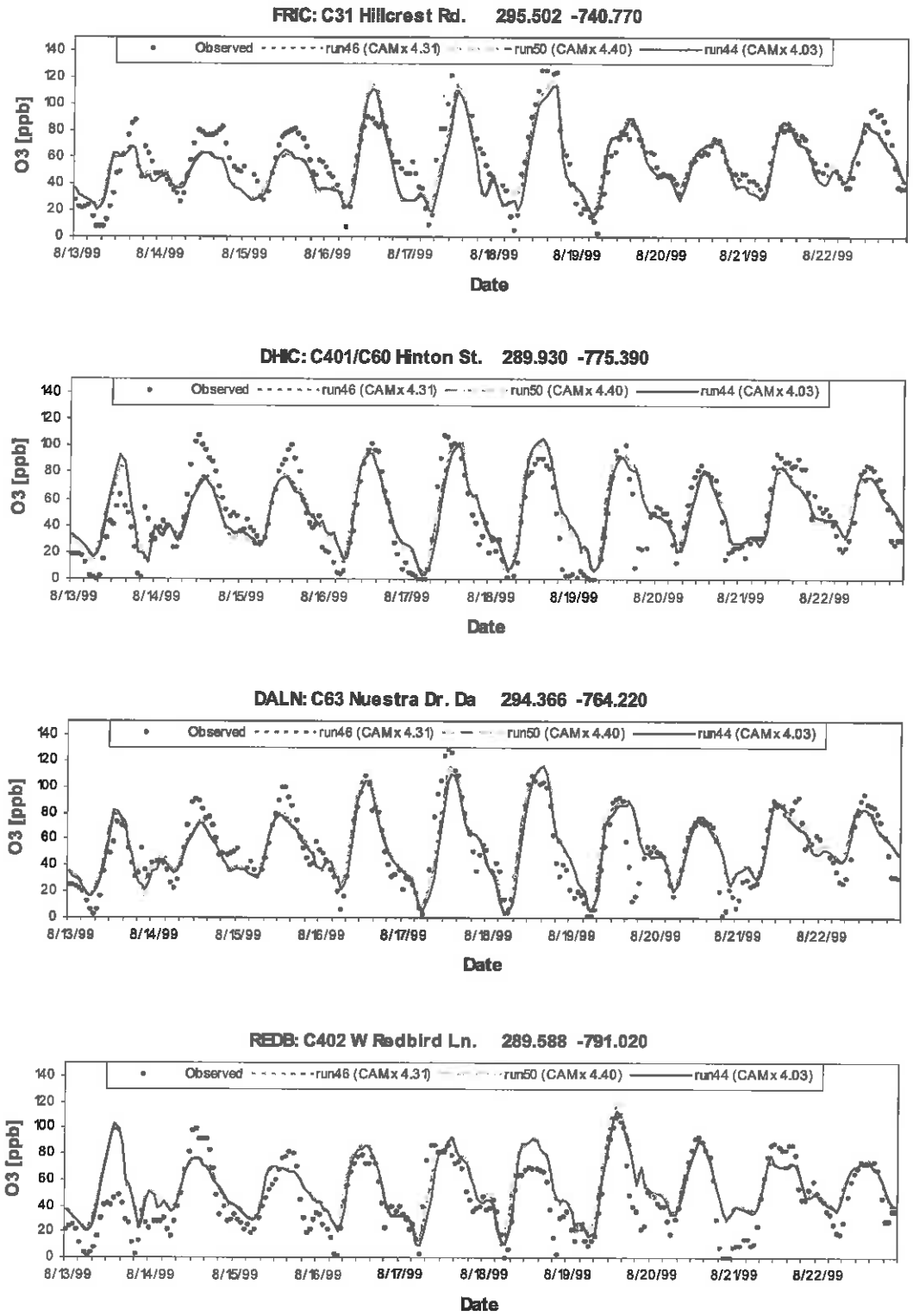


Figure 2-15a: Hourly Time Series for the 1999 Baseline Comparing Three CAMx Versions

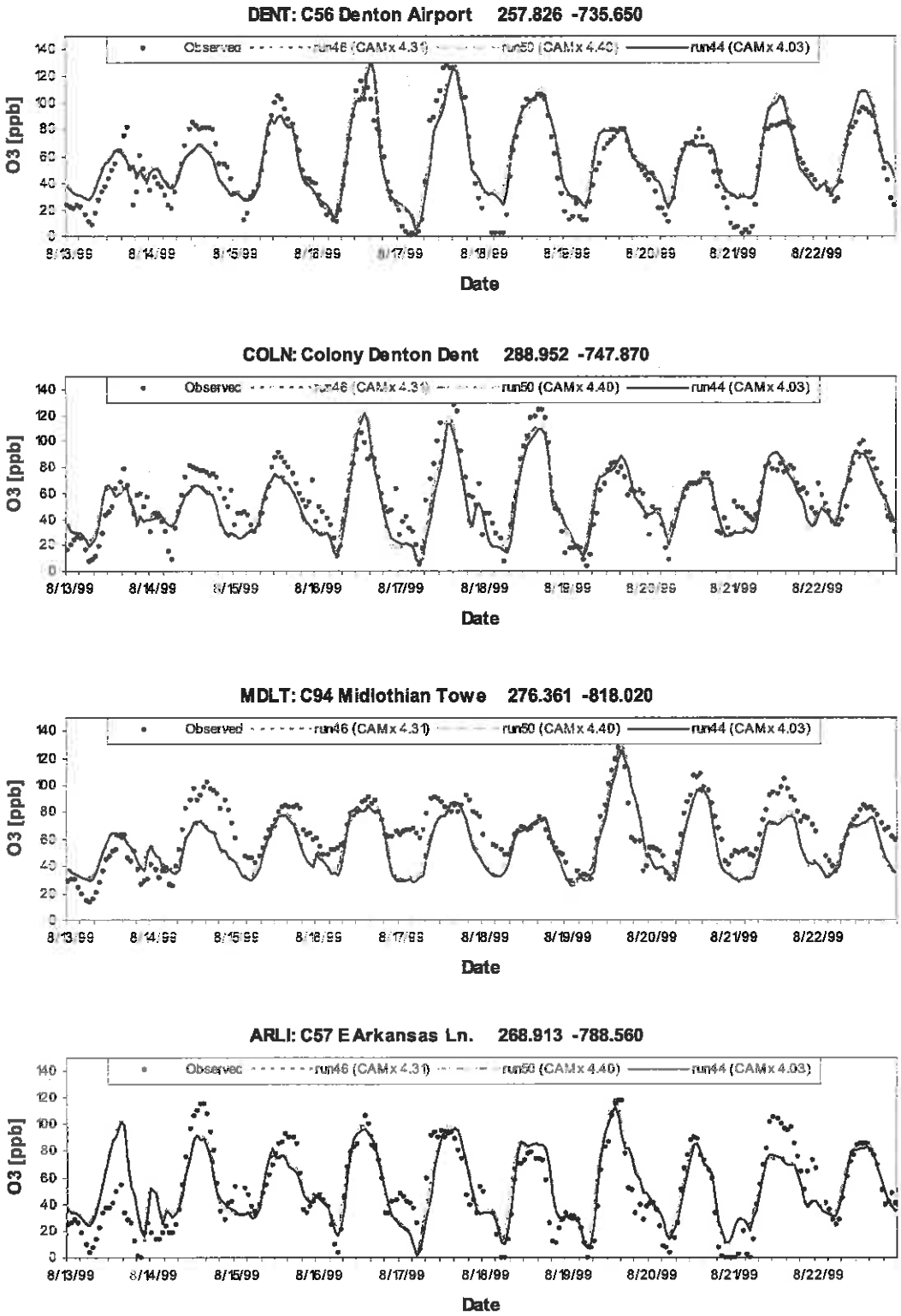
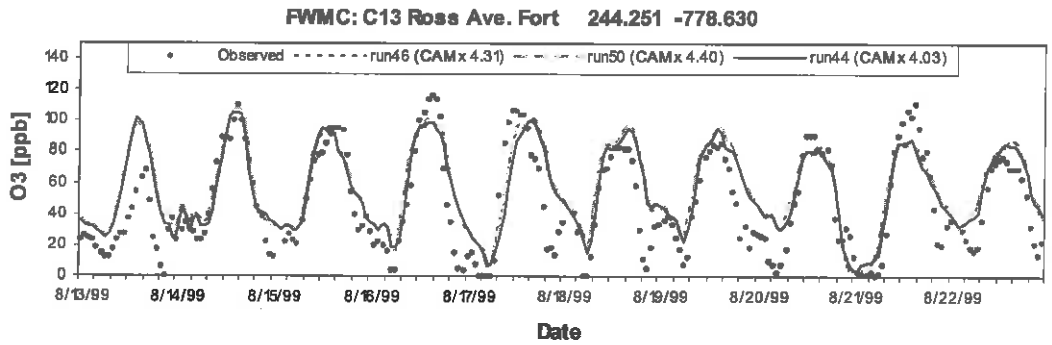


Figure 2-15b: Hourly Time Series for the 1999 Baseline Comparing Three CAMx Versions



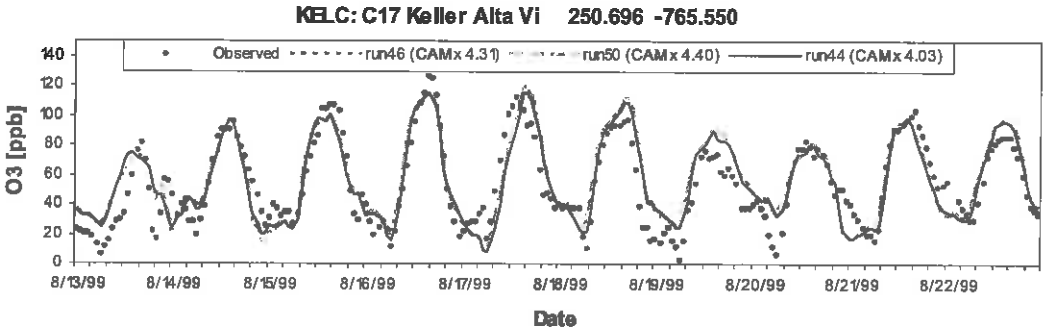


Figure 2-15c: Hourly Time Series for the 1999 Baseline Comparing Three CAMx Versions

2.7 DEVELOPMENT OF DFW 2009 FUTURE BASELINE AND SENSITIVITY TESTS

Overview

The purpose of the future baseline case and sensitivity tests is to determine:

- whether the area will attain the ozone standard without any additional controls;
- the estimated amount of emissions reductions that may be required to meet the standard;
- whether the area is more responsive to VOC or NO_x controls;
- which geographical areas are most difficult to bring into compliance; and
- the model response to different categories of controls.

Typically the first step is done with a future case baseline model run using the same meteorology that was validated in the base case, but using a future case inventory that accounts for growth and existing rules, without any additional controls. If the future case ozone design values are below 85 ppb at all monitors, attainment has been demonstrated. If not, modeling sensitivities are run to determine the type and amount of reductions that may be required to bring the area into attainment and then which types of controls would be the most effective.

Background

As discussed previously, the DFW eight-hour ozone episode (August 13-22, 1999) has been under development for several years, and both the meteorology and the emissions have been continuously upgraded and improved over time. Initially, it was assumed that EPA would require an attainment demonstration for 2010, so emissions development was started with a goal of 2010 attainment. As a result, the TCEQ has developed modeling for both the 2009 and 2010 attainment years. The model has been producing consistent directional guidance and conclusions for both periods, even as modifications have been made to improve model performance.

The results of some of the early DFW sensitivity tests using 2010 modeling are included below. The remainder of this section addresses 2009 modeling and evaluates attainment during the 2009 ozone season.

40 Ton Test Series

In order to make a preliminary assessment of the effectiveness of NO_x and VOC controls applied to different emissions source categories, a series of sensitivity runs imposing various emissions reductions on the 2010 inventory was completed. Each emissions category was reduced by the same amount, separately, to maintain comparability between categories. For example, 40 tons of NO_x were removed from the point source emissions inside the DFW nine-county nonattainment area and tested in the model. Then 40 tons of NO_x were removed from the on-road mobile, separately, and then from the area/non-road categories. Finally 40 tons of VOC were removed from the on-road mobile and area/non-road components separately, VOC from point sources was not tested since they do not emit enough VOC to be comparable. The graphical results of these runs are shown in Figure 2-16: *DFW 40 Ton Test Response Chart.*

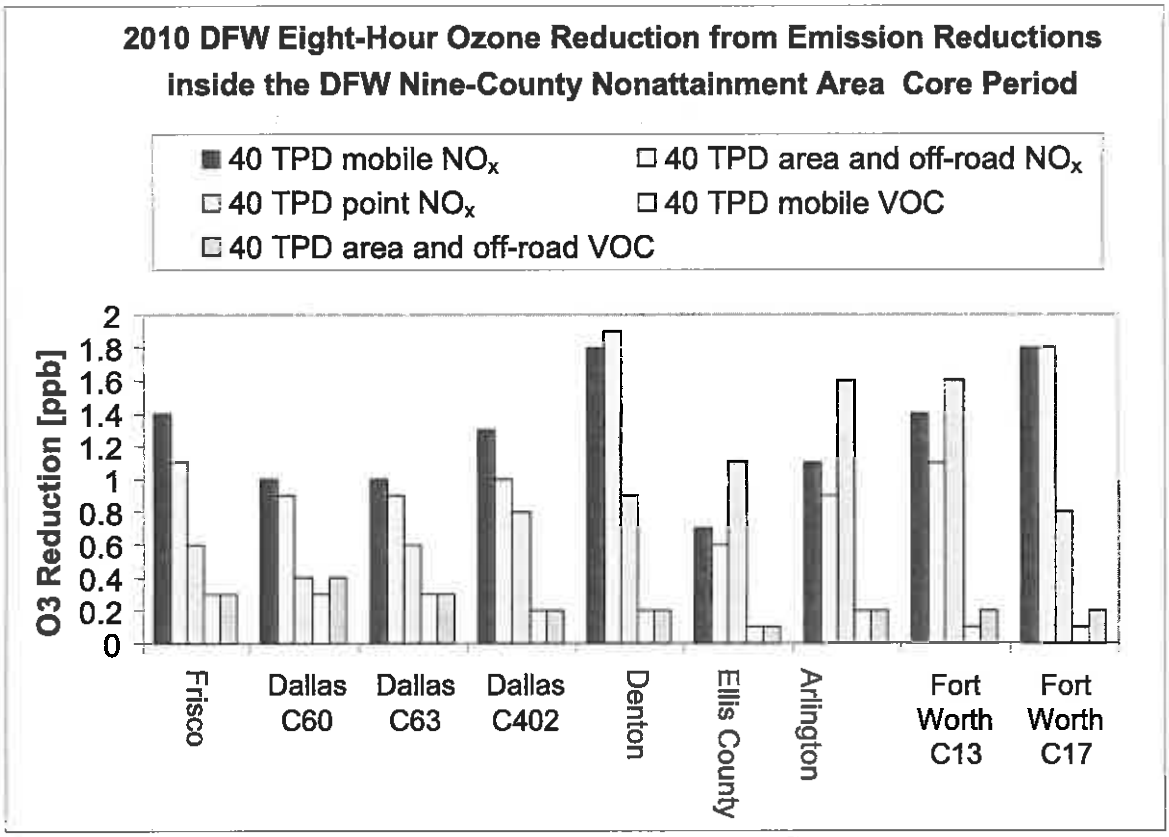


Figure 2-16: DFW 40 Ton Test Response Chart

The 40 ton test series shows that DFW ozone is more responsive to NO_x reductions than to VOC reductions in all areas. For example, 40 tons of NO_x controls inside the DFW nine-county area reduce ozone by as much 1.9 ppb at the Denton monitor, and 1.8 ppb at the Fort Worth-C17 monitor. In contrast, 40 tons of VOC reduction reduces ozone by 0.4 ppb at the Hinton Drive monitor and 0.1 ppb at the Ellis County monitor.

In terms of source categories, reducing on-road mobile and area/non-road NO_x by 40 tons inside the nine-county area is more effective than equivalent NO_x reductions applied to point sources at six out of the nine sites. On-road mobile source NO_x reductions are more effective than area/non-road reductions at all sites except the Denton monitor. However, point source NO_x reductions are

more effective than on-road mobile or area/non-road reductions at the Ellis County, Arlington, and Fort Worth-C13 monitors.

While all areas are responsive to NO_x reductions, the degree to which they respond varies. The 40 ton test series indicates that the DFW area is not homogeneous and that different areas respond differently to VOC and NO_x controls. Some areas of the city respond better to mobile and area source controls, whereas other areas respond better to point source controls.

The monitors in the urban core (Dallas-C6- and Dallas-C63) tend to be more responsive to VOC controls than those in other areas. In contrast, monitors downwind of the city (where the highest concentrations of ozone are measured) are NO_x limited and more responsive to NO_x controls. Overall, the NO_x controls are more effective than VOC controls.

Control Strategy Sensitivity Tests
The relative effectiveness of the different control strategies that were under consideration was evaluated. Each of the proposed control strategies was tested in the 2009 future case using the same CAMx version (4.03), meteorology (Run 44), and the same emissions inventory (.a1) so that all results would be comparable. Each strategy was initially tested separately to compare the relative effect and determine the most effective ones. Strategies were also tested to compare the relative effectiveness of controls applied inside the DFW nine-county area with controls applied in other areas of Texas.

For a list of all of the future case sensitivity tests to date, please refer to Appendix D: *DFW Future Case (2009) Sensitivity Tests*. This appendix describes the effect of those reductions on the Frisco and Denton monitors, as well as the average ozone reduction over the DFW area and the reduction in area of exceedance that resulted from the strategy. The results of all of these tests are discussed in detail in Tai, 2006b.

On a ton-for-ton basis, reductions made in the surface layers of the model are more effective than reductions made in elevated emissions. In addition, reductions made inside the DFW nine-county nonattainment area are more effective than similar reductions applied to distant sources. The response to NO_x reductions is progressive: the larger the total reductions, the more effective they become.

Based on the results of these tests, combinations of the more effective control sensitivities were selected for testing. The results of these combination runs, the modeled design values, and the final package of control strategies proposed are discussed in Section 2.9.

2.8 DFW FUTURE BASELINE CASE (2009) MODELING RESULTS

Overview
This section explains how much ozone was generated in the DFW 2009 future baseline case and how the future ozone design values are calculated. The future baseline case includes only the controls that are already enacted in law and expected to be in effect by 2009. No additional controls or reductions are assumed. Additional controls adopted as part of this SIP revision and their effect upon future design values are not included in the future baseline case. The effects of the future control strategies are discussed in Section 2.9.

Two additional adjustments were made to the 2009 baseline modeling, including an upgrade to CAMx 4.31 and a future case emissions inventory adjustment. The 2009 emissions inventory incorporated an update based on the EPA's 2005 Acid Rain data.

Projecting Future Design Values

In their most recent eight-hour ozone modeling guidance (EPA, 2005), the EPA describes a new procedure for estimating future case ozone expected to occur in the attainment year. This procedure is designed to eliminate some of the concerns of the previous one-hour procedure, which was based strictly on the modeled maximum future case ozone. In some of the one-hour cases the future modeled ozone was biased high, in other cases it was biased low. If the ozone in the future case ozone was too high, a significant level of controls would be required to reduce the value down to the standard. If the future case ozone was biased low, a smaller reduction (possibly even no additional controls) would be required to bring the area into compliance.

The new EPA procedure calculates a ratio between the base and future case ozone, which is then applied to the measured ozone values to estimate future ozone levels. The procedure is based upon two elements: the baseline design value and the relative reduction factor.

The baseline design value is an EPA term designed to represent the ozone that occurred in the past, as well as representing the value that must be reduced to meet the eight-hour ozone standard. The EPA recommends calculating the current design value by averaging the three, three-year design values that occurred in the area for the following specific periods: the year before the base year selected for modeling; the base year; and the year after the base year selected for modeling. Mathematically speaking, the new procedure recommends a five year center-weighted average of the fourth high eight-hour ozone concentrations measured at each monitor in the area. Since it is center-weighted, the calculation emphasizes the ozone that was measured during the base year. The baseline design value is the foundation for estimating the ozone that the model predicts will occur in the attainment year.

The relative reduction factor (RRF) is the second element used to estimate future ozone levels. The relative reduction factor is based on modeling and describes the amount of reduction expected to occur in the future year for a particular level of control. RRFs are calculated for each monitor individually by dividing the future year ozone modeled at a site by the base year ozone modeled at the site, expressed as a three digit decimal number. For example, a RRF of 0.900 indicates that future ozone is expected to be 90 percent of the base year ozone.

Once both elements are calculated for every monitor in the area, the baseline design value is multiplied by the RRF to determine the ozone predicted in the future at each monitor. For example, if the base year design value was 90 ppb, and the RRF was 0.900, the calculated future design value would be 81 ppb.

DFW 1999 Baseline Design Value

The DFW modeling base year is 1999; therefore, the EPA baseline design value is determined by averaging the three annual design values from the year before (1998), the base year (1999), and the year after (2000). Table 2-3: *DFW 1999 Baseline Design Value Calculations* shows the values for each period for each of the monitors operating in the DFW area during the period. The last column shows the baseline design value, calculated as the average of the other three columns.

Table 2-3: DFW 1999 Baseline Design Value Calculations

Site Name	1999 97-99	2000 98-00	2001 99-01	Baseline DV
	ppb	*ppb*	*ppb*	*ppb*
Frisco C31	101	101	99	100.3
Anna C68				---
Dallas Hinton C60	91	93	92	92.0
Dallas North C63			93	93.0
Dallas Exec (Redbird) C402	92	88	84	88.0
Denton C56		102	101	101.5
Midlothian C94		97	88	92.5
Arlington Reg Office C57		95	86	90.5
FtW NW (Meacham) C13	99	99	97	98.3
FtW Keller C17	95	97	97	96.3

DFW Relative Reduction Factor (RRF) Calculations

The EPA recommends a two-step procedure to calculate the relative reduction factors that averages the base case and future case ozone concentrations at a monitor before calculating the RRF. Since the essential element of the EPA attainment test is applying the relative reduction ratio to the baseline ozone, it is important to maintain the integrity of the individual day and monitor-specific RRFs. Since averages are distorted by extremely high and low values, the EPA averaging-first method may distort the relationship the RRF is attempting to calculate.

The EPA method for calculating future design values is straightforward, but it masks some of the information otherwise available. Since the EPA method averages the daily ozone over all the days of the episode, it substitutes a statistical assessment for a dynamic cause and effect analysis. Effectively, the method smooths over the model performance information that is contained in the daily response data.

As allowed in the EPA's modeling guidance (EPA 2005a) in the Foreword and on page 30, the TCEQ is using an alternative method to calculate future design values by calculating the ratios for each day and monitor first, and then averaging the ratios. This method preserves the relationship RRF between the base and future case at each monitor, and thereby the integrity of the RRF method. This daily method provides additional insight into daily model performance by showing which days and areas respond to precursor reductions. When combined with data on wind directions, internal and external sources, and source alignments, the daily response data permits analysis of VOC/NO_X sensitivities in different portions of the urban area.

Comparisons of the two methods show that in most cases, the results are similar. Figure 2-17: *Comparison of EPA RRF Calculation Method with Daily Calculation Method* shows that the two methods give almost the same results except at monitors with extremely high or low calculated ozone values. The regression equation shows that TCEQ's daily method is strongly correlated with the EPA method (R^2=.9881), and the regression line for the daily RRF is only 1.9 percent different from the EPA calculations. Since the EPA recommends truncating (discarding) the last digit in the future design value calculations, in most cases the 1.9 percent difference between the two methods is relatively unimportant.

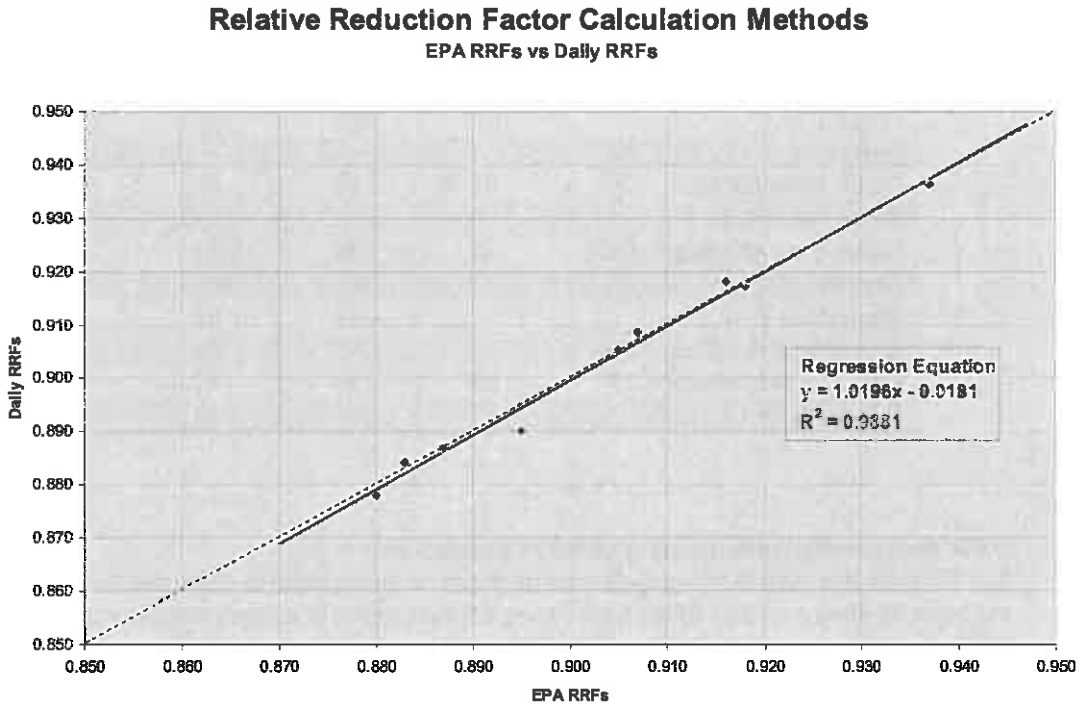


Figure 2-17 Comparison of EPA RRF Calculation Method with Daily Calculation Method

Daily Relative Reduction Factor Calculations

Table 2-4: *DFW 2009 Baseline RRF Calculations Using CAMx 4.31 and .a2 Emissions* shows the RRF calculations using the TCEQ's daily RRF method. The top two panels of Table 2-4 show the modeled ozone output at each monitor in the 1999 base and 2009 future case using the latest model configuration, Run 46 with CAMx 4.31 and the .a2 version of the inventory.

The EPA guidance recommends removing base case data points that are less than 85 ppb because those days do not respond well to controls. The data from the Frisco monitor from August 20 is colored orange in both the base and future cases to show that the data were not used in the daily RRF calculations, as recommended by the EPA. Although base case ozone was modeled below 85 ppb at several monitors, the TCEQ has taken a more conservative approach by only removing data less than 70 ppb. This removes only the very lowest values, while still leaving enough data to develop stable averages. However, leaving the other low values in the calculation makes the RRFs less responsive and ultimately results in higher (more conservative) future design values.

The third panel of Table 2-4, *DFW 2009 Baseline RRF Calculations Using CAMx 4.31 and .a2 Emissions* shows the daily RRFs calculated for each monitor, color coded to indicate the amount of response. Numbers labeled in blue represent RRFs less than 0.9, indicating that on that day ozone was reduced between 10-20 percent in the future case. Numbers in black indicate that the future modeled ozone was reduced from 0-10 percent compared to the base case. Numbers colored red indicate that the future case ozone increased at those monitors.

The color coding in the third panel illustrates the insight that can be gained by using daily RRF calculations. For example, when the RRFs are colored blue, it indicates that the model responds well on that day. The blue RRFs on August 15, 16, 18, 19, 21 and 22 indicate that the model is responding well to the future case ozone reductions on many days during the episode.

However, the daily RRF data also show RRFs greater than 1.0 at several sites on August 17 and 20, indicating that the ozone at these monitors increased in the future case (2009) compared to the

baseline (1999). Since the biggest reductions between 1999 and 2009 were due to the NO_x component of the inventory, the RRF results suggest that ozone in the city core is probably being scavenged by mobile NO_x emissions, and as those NO_x emissions are reduced in the future, less scavenging leads to increased ozone in those areas.

Table 2-4: DFW 2009 Baseline RRF Calculations Using CAMx 4.31 and .a2 emissions

1999 Base Case: run46

Site	990815	990816	990817	990818	990819	990820	990821	990822	#Days>70
Frisco C31	81.3	107.0	102.6	109.2	86.0	[illegible]	87.1	89.5	7
Dallas Hiinton C60	83.1	99.8	103.4	103.8	99.2	78.0	85.5	85.3	8
Dallas North C63	82.6	101.3	102.6	106.6	96.5	76.4	86.8	88.4	8
Dallas Redbird C402	77.0	93.3	98.5	96.6	107.4	83.7	79.4	79.5	8
Denton C56	102.6	113.1	110.0	112.5	84.7	73.1	101.6	99.6	8
Midlothian C94	78.3	86.1	85.9	76.2	114.0	88.8	75.7	76.7	8
Arlington C57	86.2	98.4	100.2	95.2	106.9	83.1	81.9	86.7	8
FtW NW C13	93.8	105.5	104.3	106.0	96.0	80.1	89.8	92.0	8
FtW Keller C17	101.1	111.1	110.4	108.3	92.4	78.6	95.9	94.9	8

2009 Future Base: run46.fy2009.a2 (No Additional Controls)

Site	990815	990816	990817	990818	990819	990820	990821	990822
Frisco C31	67.7	100.9	101.9	100.5	73.2	[illegible]	74.8	74.4
Dallas Hiinton C60	73.1	93.0	103.5	97.8	91.4	80.7	78.0	74.0
Dallas North C63	71.0	95.6	101.9	99.7	84.4	77.4	76.2	74.1
Dallas Redbird C402	66.7	82.4	89.5	85.1	97.0	85.2	70.3	71.3
Denton C56	88.5	103.4	108.0	92.0	71.6	64.6	89.8	83.5
Midlothian C94	72.6	77.3	78.8	70.3	99.0	85.7	69.9	70.7
Arlington C57	75.0	89.2	90.6	81.8	95.5	85.2	73.1	79.6
FtW NW C13	80.9	94.7	94.3	87.9	83.6	75.7	79.2	81.1
FtW Keller C17	89.3	99.1	104.4	90.3	79.2	70.6	88.1	82.2

Daily RRF Calculations			(With August 20th Removed)						Average
Site	990815	990816	990817	990818	990819	990820	990821	990822	RRF
Frisco C31	0.833	0.942	0.993	0.921	0.851	—	0.859	0.831	0.890
Dallas Hinton C60	0.88	0.932	1.001	0.942	0.921	1.035	0.912	0.867	0.936
Dallas North C63	0.86	0.944	0.993	0.935	0.875	1.014	0.878	0.838	0.917
Dallas Exec C402	0.866	0.883	0.908	0.881	0.903	1.018	0.886	0.897	0.905
Denton C56	0.863	0.914	0.982	0.817	0.845	0.883	0.883	0.838	0.878
Midlothian C94	0.927	0.898	0.917	0.922	0.869	0.966	0.923	0.922	0.918
Arlington C57	0.87	0.907	0.904	0.859	0.894	1.025	0.892	0.918	0.909
FtW NW C13	0.863	0.897	0.904	0.83	0.871	0.945	0.882	0.881	0.884
FtW Keller C17	0.883	0.893	0.946	0.834	0.857	0.898	0.919	0.866	0.887

Future (2009) Design Values

The future design values for the DFW area in 2009 are calculated in Table 2-5: *2009 Design Value Calculations*. The first column indicates the monitor site name; the second column shows the 1999 baseline design value taken from Table 2-3, *DFW 1999 Baseline Design Value Calculations*; and the third column shows the average RRF for that monitor. The future design values are shown in the last column, calculated by multiplying the average RRF by the 1999 baseline design value. The EPA recommends truncating the last digit of the calculation; however, the TCEQ shows the last decimal place in the calculation for clarity.

Table 2-5: 2009 Design Value Calculations

	2009 Baseline		
Site Name	Baseline DV	Average RRF	Future DV
	ppb		*ppb*
Frisco C31	100.3	0.890	**89.3**
Dallas Hinton C60	92.0	0.936	**86.1**
Dallas North C63	93.0	0.917	**85.3**
Dallas Exec C402	**88.0**	0.905	**79.7**
Denton C56	101.5	0.878	**89.1**
Midlothian C94	92.5	0.918	**84.9**
Arlington C57	90.5	0.909	**82.2**
FtW NW C13	98.3	0.884	**86.9**
FtW Keller C17	96.3	0.887	**85.4**

Summary

Of all the monitors, the Frisco monitor had the highest calculated future design value at 89.3 ppb. The second highest future design value was 89.1 ppb calculated at the Denton monitor. Although the Denton monitor started with the highest baseline design value, it also had the lowest (most effective) RRF. As a result, the Denton monitor shows the largest change between the base and future case, with a future design value below the Frisco monitor value.

The future (2009 Baseline) calculations show that the future case ozone is below 85 ppb at only three monitors, Dallas Executive, Midlothian, and Arlington. Thus additional controls are needed.

According to the 1999 baseline data, all of the sites in the DFW area were out of compliance in 1999. Therefore, according to the modeling, the controls that have already been adopted with compliance dates prior to 2009 are expected to bring three out of the nine monitors below 85 ppb.

Reversing the order of operations in the RRF calculations by determining the daily response at each monitor before averaging the RRFs to derive a monitor-specific RRF results in essentially the same number as the EPA calculation methodology but preserves the daily response information. The advantage of the daily RRF method is that it allows the TCEQ to analyze the daily response in each area of the city, to evaluate the responses with different wind directions, and to evaluate whether the model is performing as expected.

2.9 DFW FUTURE CASE (2009) WITH CONTROLS MODELING RESULTS

Overview

This section evaluates and describes the effect of the VOC and NO_X emissions controls included in this SIP revision. Section 2.7 described the results of the individual sensitivity tests performed to evaluate the effectiveness of various options for emissions reduction. Section 2.8 illustrates the controls already in place provide emissions reductions benefits toward attaining the eight-hour ozone standard, but that additional controls are required to bring to attain the ozone standard. This section describes the modeling results with the additional controls and uses the Daily RRF method to calculate the future design values and attainment status for the 2009 future case.

2009 SIP Control Package

The TCEQ evaluated various options for controlling DFW ozone and selected a package of controls to bring the area into attainment of the ozone standard. Several different packages were tested with CAMx 4.31, and the tenth combination represents the strategies being implemented through this SIP. Combination 10 includes reductions for the following: DFW major and minor sources, DFW electric generating facilities (EGFs), Ellis County cement kilns, NCTCOG on-road and off-road VMEP and TCM commitments and certain stationary engines located in 33 counties that are within 200 km of DFW. Table 2-6: *2009 Control Package Emission Reductions (Combination 10 compared to 2009 .a2 Baseline),* shows the list of controls included in Combination10 by emissions category.

Table 2-6: 2009 Control Package Emission Reductions (Combination 10 compared to 2009.a2 Baseline)

2009 Emissions Reductions in DFW SIP Revision		
Control	NOx reduction	VOC reduction
	tpd	*tpd*
DFW Major Source, nine-county area	-9.0	0.0
DFW Minor Source, nine-county area	-3.0	0.0
DFW EGFs, nine-county area	-0.4	0.0
Ellis County Cement Kilns	-10.4	0.0
NCTCOG Off-Road Mobile[1]	-2.2	+0.5
NCTCOG On-Road Mobile[1]	-1.4	-0.5
Surface Coatings	0.0	-0.1
On Road Mobile Outside DFW	+4.4	+1.0
Off Road Mobile Outside DFW	+1.7	+1.9
East Texas (33 counties)[2]	-22.4	0.0
TOTALS	**-42.7**	**+2.9**

1-The DFW mobile source emissions estimates used in the SIP proposal were based on NCTCOG's initial VMEP assumptions. NCTCOG's refined estimate is 2.63 tpd of NO_X reductions. The Combination 10 control strategy also includes a 1.1 tpd NOx reduction for TxLED fuels in locomotives as well as some adjustments for Houston area mobile emissions. Combination 10 includes all of the corrections and final rule revisions incorporated in this SIP revision.

2-The proposed East Texas Combustion rule for gas-fired engines originally affected 39 counties within or traversed by the 200 km perimeter from DFW. The 2009 emissions reductions from the final East Texas Combustion rule in this SIP revision applies to 33 counties and rich-burn engines, and are estimated at approximately 22.4 tpd of NOx. The Combination 10 control strategy run incorporates these corrections.

2009 Emissions with Combination 10 Controls

Table 2-7: *Weekday NO_X Emissions (tpd) for 2009 with DFW Combination 10 Controls* and Table 2-8: *Weekday VOC Emissions (tpd) for 2009 with DFW Combination 10 Controls* summarize the NO_X and VOC reductions by county as tested in the 2009 future case with Combination 10 control package. Texas NO_X and VOC emissions were reduced 42.6 and 2.8 tpd, respectively, from the 2009.a2 baseline.

Table 2-7: Weekday NO_X Emissions (tpd) for 2009 with DFW Combination 10 Controls.

	Bio	TX Mobile	Elev Points	TX Low Points	TX Area	TX Off-Road	Non-TX Low Anthro	All Anthro	Anthro Change from 2009.a2 Baseline
Collin Co	10	14	1	0	2	8	0	25	-0.3
Dallas Co	4	77	5	1	18	44	0	145	-3.5
Denton Co	8	17	1	0	11	9	0	38	-2.1
Tarrant Co	3	46	1	1	10	27	0	86	-3.2
Parker Co	1	6	0	0	1	2	0	8	-1.1
Johnson Co	5	5	3	0	0	5	0	13	-2.2
Ellis Co	15	8	22	0	0	6	0	36	-12.8
Kaufman Co	5	6	4	0	0	2	0	12	-0.4
Rockwall Co	2	3	0	0	0	1	0	5	-0.1
DFW 9-County	**52**	**182**	**37**	**3**	**41**	**105**	**0**	**369**	**-25.7**
North Texas	31	24	13	3	17	15	0	72	-0.7
NE Texas	16	79	181	10	68	42	1	380	-13.5
Central TX	114	92	143	2	58	70	0	366	-7.6
Houston	21	179	226	11	53	63	0	532	4.4
South TX	229	189	261	21	75	100	0	647	-1.2
West TX	524	160	140	21	212	106	1	641	1.6
Texas	**986**	**907**	**1001**	**72**	**525**	**501**	**2**	**3008**	**-42.6**
Gulf + Mexico	79	5	436	0	4	2	444	891	0.0
Oklahoma	227	1	256	0	2	3	661	924	0.0
Louisiana	106	1	715	1	2	1	1183	1903	-0.1
Arkansas	125	2	220	0	0	2	468	692	0.0
Mississippi	121	0	353	0	0	0	455	808	0.0
Alabama	75	0	442	0	0	0	491	932	0.0
Tennessee	118	0	244	0	0	0	662	906	0.0
Kentucky	145	0	289	0	0	0	770	1060	0.0
Georgia	110	0	408	0	0	0	823	1230	0.0
Florida	56	0	367	0	0	0	1206	1573	0.0
Mid Atlantic (SC, NC, VA, WV)	293	0	977	0	0	0	2332	3310	0.0
NE US	314	0	1302	0	0	0	5748	7051	0.0
Northern Plains	5238	0	3269	0	0	0	8623	11892	0.0
Total	**7992**	**916**	**10281**	**73**	**534**	**509**	**23869**	**36181**	**-42.7**
Change from 2009 baseline	0.0	3.0	-26.1	-10.2	-8.92	-0.4	-0.1	-42.7	

Table 2-8: Weekday VOC Emissions (tpd) for 2009 with DFW Combination 10 Controls.

	Bio	TX Mobile	Elev Points	TX Low Points	TX Area	TX Off-Road	Non-TX Low Anthro	All Anthro	Anthro Change from 2009.a2 baseline
Collin Co	27	7	0	1	12	4	0	23	0.0
Dallas Co	50	42	4	8	72	17	0	144	0.0
Denton Co	65	8	1	1	15	4	0	29	0.0
Tarrant Co	64	25	2	7	54	9	0	96	0.0
Parker Co	121	2	0	0	5	1	0	8	0.0
Johnson Co	111	2	0	0	6	1	0	9	0.0
Ellis Co	89	2	3	2	6	2	0	15	0.0
Kaufman Co	112	2	0	0	7	1	0	11	-0.1
Rockwall Co	3	1	0	0	2	1	0	4	0.0
DFW 9-County	**642**	**91**	**10**	**20**	**180**	**38**	**0**	**340**	**-0.1**
North Texas	601	8	24	2	29	5	1	69	0.0
NE Texas	4917	27	14	41	82	14	1	179	0.2
Central TX	6393	35	20	20	91	23	1	191	0.2
Houston	1683	81	91	215	247	42	0	676	1.7
South TX	2069	78	20	48	217	46	0	408	0.5
West TX	6198	59	10	28	215	52	3	367	0.3
Texas	**22503**	**381**	**188**	**374**	**1060**	**221**	**6**	**2230**	**2.8**
Gulf + Mexico	658	3	32	0	10	4	329	378	0.0
Oklahoma	7940	1	3	0	5	1	481	490	0.0
Louisiana	9941	0	47	3	4	1	546	601	0.0
Arkansas	13925	0	23	0	2	0	441	466	0.0
Mississippi	14818	0	35	0	0	0	548	583	0.0
Alabama	13954	0	39	0	0	0	655	695	0.0
Tennessee	8678	0	66	0	0	0	895	961	0.0
Kentucky	3753	0	34	0	0	0	622	656	0.0
Georgia	12198	0	53	0	0	0	869	922	0.0
Florida	9793	0	42	0	0	0	1594	1636	0.0
Mid Atlantic (SC, NC, VA, WV)	31294	0	67	0	0	0	2836	2903	0.0
NE US	20472	0	248	0	0	0	5407	5655	0.0
Northern Plains	40144	0	226	0	0	0	8224	8450	0.0
Total	**210073**	**385**	**1104**	**377**	**1080**	**227**	**23453**	**26625**	**2.9**
change from baseline	0.0	0.5	0.0	-0.1	0.0	2.4	0.0	2.9	

Future Case Model Response with Combination 10 Controls

Spatial plots of the daily maximum eight-hour ozone in 2009 with Combination 10 analyses and the control differences from the 2009 baseline are shown in Figure 2-18: *Spatial Plots of the Daily Maximum Eight-Hour Ozone in 2009 with Combination 10 Controls* for each episode day in the DFW 4 km domain. On four days (August 15, 16, 21 and 22), the difference plots show that the largest ozone reductions occurred in plumes downwind of the Ellis County cement kilns and benefited Tarrant County. These plumes reflect the combined ozone benefit of all of the controls modeled in Combination 10.

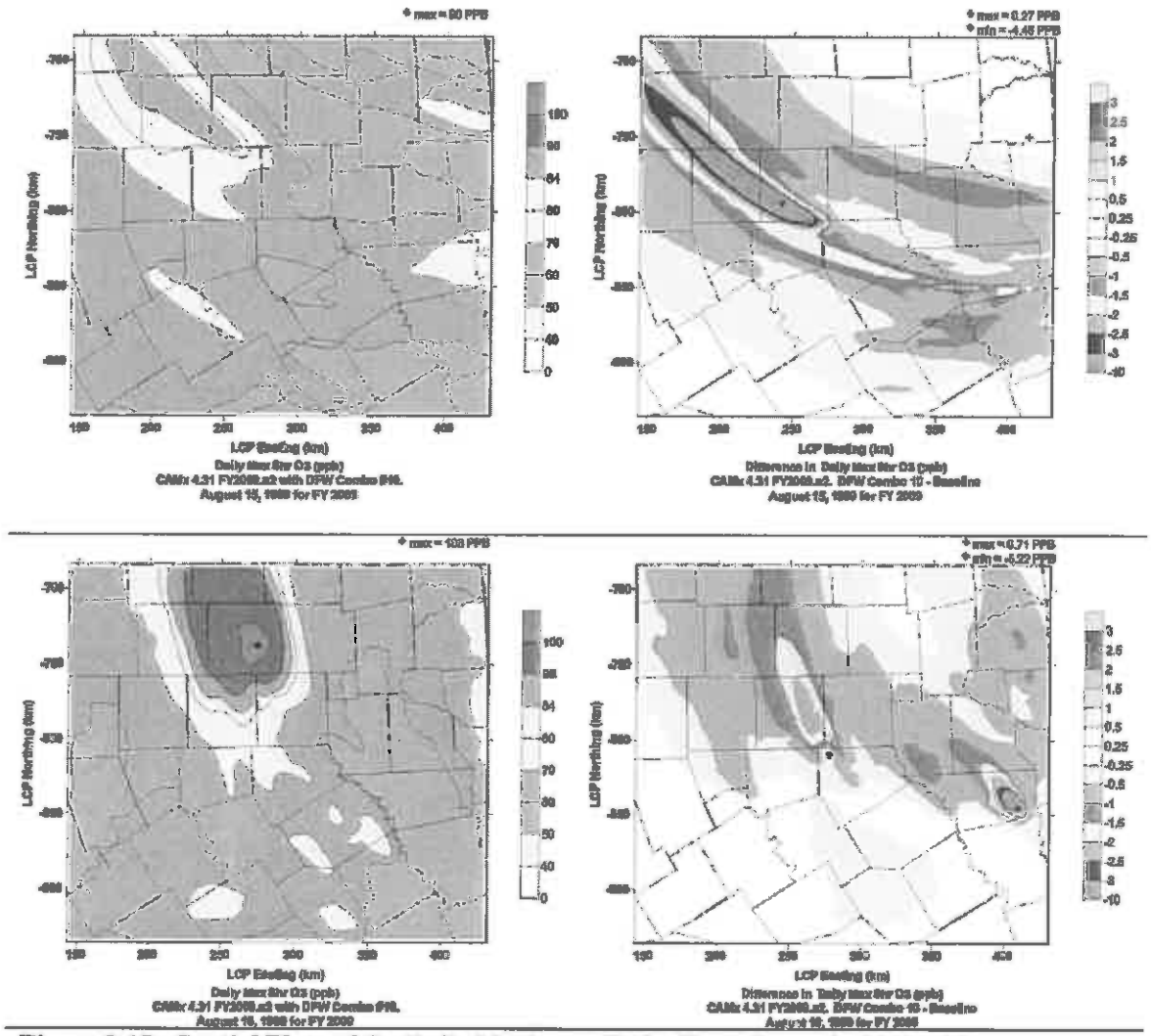


Figure 2-18: Spatial Plots of the Daily Maximum Eight-Hour Ozone in 2009 with Combination 10 Controls, and Differences from the 2009 Baseline for Each Episode Day in the DFW 4 km Domain