APPENDIX B: Written Comments Submitted by Small Entity Representatives

- Hoosier Energy Rural Electric Cooperative comments
- Southern Illinois Power Cooperative comments
- Kansas Municipal Utilities comments
- San Miguel Electric Cooperative comments
- Illinois Municipal Electric Agency/Illinois Municipal Utilities Association comments
- LS Power Development comments
- Wabash Valley Power comments
- City of Orrville, Ohio comments
- National Rural Electric Cooperative Association comments
- Western Farmers Electric Cooperative comments
- Golden Spread Electric Cooperative comments
- American Public Power Association comments
- Arizona Electric Power Cooperative comments
- Sunflower Electric Power Corporation comments

HOOSIER ENERGY
A Touchstone Energy® Cooperative

2501 South Cooperative Way
P.O. Box 908
Bloomington, IN 47402-0908
Office 812-876-2021
Fax 812-876-3476
HEPN.com

Hoosier Energy Rural Electric Cooperative, Inc. Comments to the Small Business Advocacy Review Panel on Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014

May 26, 2015

Hoosier Energy Rural Electric Cooperative, Inc. (Hoosier Energy) is a non-profit generation and transmission cooperative providing wholesale power and services to 18 non-profit, consumer-owned member distribution cooperatives. Collectively, our member cooperatives provide electric service to nearly 300,000 consumers in southern Indiana and southeastern Illinois. With 473 employees, Hoosier Energy is considered a small fossil electric power generation utility as defined by the Small Business Administration.

Hoosier Energy appreciates the opportunity to serve as a Small Entity Representative (SER) and provide comments to the Small Business Advocacy Review Panel on EPA's Clean Power Plan Federal Plan (FP). In an effort to facilitate dialogue we provided our questions, comments and alternative proposal at the May 14th outreach meeting *(copy attached).* The EPA provided very little detail to the SERs regarding the FP throughout this process much to our disappointment. Based upon the extremely limited information that has been provided, we offer the following comments for the SBAR Panel's consideration:

The FP needs to recognize and preserve the remaining useful life of existing generation facilities.

- Compliance with the proposed rule will reduce the utilization of coal fired units, and in many cases, force units to prematurely shut down. This will result in stranded assets and require cooperative consumers to pay off the costs remaining on assets that are no longer operating while at the same time paying for new replacement generation. In many instances this doubling of costs on consumers occurs not for a brief period, but for decades and places an undue hardship on cooperative consumers. Cooperatives do not have shareholders to help shoulder this financial burden; a cooperative consumer is both owner and ratepayer.
- Since 2005, Hoosier Energy, like many small utilities, has invested hundreds of millions of dollars at our Merom coal plant to comply with numerous air, solid waste and water regulations issued by EPA. These investments and the related

financings were made on the basis of a remaining useful life much greater than the time horizon of the Clean Power Plan.

- Hoosier Energy's most recent loan from the U.S. Department of Agriculture's Rural Utilities Service (first advanced in March 2015) anticipates a remaining useful asset life of 33 years or longer. The loan will not be fully repaid until 2045.
- Hoosier Energy anticipates that additional investments totaling $179 million will be required through 2019 to comply with EPA's 316 (a), 316 (b), Mercury and Air Toxics Standards, National Ambient Air Quality Standards, coal combustion residuals and effluent guidelines. Financing of these ongoing investments will likely place final debt maturities to at least 2050. The FP should provide for units to operate for their remaining useful life and until the underlying debt has been repaid.

Credit should be given to and retained by utilities for coal plant retirements.

- Retirements of coal facilities occurring after the baseline year should be credited to the utility that retired the plant in perpetuity.
- Investments in compliance activities before the rule goes into effect should be carried forward into the compliance timeline as an additional source of compliance credits, allowances or offsets.
- The FP should be clear about the treatment of these credits, allowances and offsets as they are crucial to compliance efforts.

Concerns with Rate-Based, Unit-by-Unit Approach

- During SBAR Panel discussions, EPA made reference to the nature of the 111(d) rule ultimately applying on a unit-by-unit basis and acknowledged that no coal unit can meet the proposed emission rate without acquiring credits from a market—a market which does not exist today. EPA has provided little or no information to SERs on how that market might be structured or work.
- EPA has not provided clarity on whether a FP will be rate-based or mass-based. If the FP establishes a unit-by-unit emission rate consistent with the proposed state interim and final rate-based goals, it appears that no coal unit will be able to stay online. The FP must specifically address how coal units can possibly comply in such a circumstance.

Offsets for energy efficiency should be measured using deemed energy savings.

- Energy efficiency is a large part of compliance in the proposed rule. EPA assumes that nearly half of Indiana's CO_2 reductions from 2012 to 2030 will come from end-use energy efficiency measures.
- Measurement and verification, if done improperly, can become the largest expense in an energy efficiency program removing resources from the actual efficiency measures.
- Deemed energy savings, using validated and specific savings calculations for specific efficiency measures, is an appropriate and cost-effective way to measure energy efficiency savings.
- This is currently the method by which Hoosier Energy and the State of Indiana measure energy efficiency savings.
- The FP should specifically recognize deemed energy savings as the method for quantifying energy efficiency actions. If the Federal government established and used deemed energy ratios it would create a unified measure across states which would foster exchangeable credits, allowances or offsets.

Renewable energy is much broader than wind and solar.

- Currently, EPA recognizes only wind and solar as renewable energy generation sources.
- The FP should broaden renewable resources to include hydro-electric, landfill methane, coalbed methane, waste heat, and biomass. All are recognized as reducing greenhouse gas emissions and excluding them as potential sources of credits, allowances or offsets is arbitrary and capricious.
- EPA's own website states, methane is a 25 times more potent greenhouse gas than carbon dioxide. In order to accurately achieve the proper reduction incentives, the FP should include, at a minimum, a 25 times multiplier for emission credits associated with methane destruction.
- Many utilities have coal generation and renewable generation located in different states. The FP should clarify that a utility is permitted to use credits, allowances or offsets from renewable generation regardless of what state the renewable generation is located in for purposes of meeting its emission limit on coal units.

HOOSIER ENERGY
A Touchstone Energy® Cooperative

2501 South Cooperative Way
P.O. Box 908
Bloomington, IN 47402-0908
Office 812-876-2021
Fax 812-876-3476
HEPN.com

Attachment to May 26, 2015
Comments to
Small Business Advocacy Panel

SBAR Panel Discussion on Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014

May 14, 2015

Hoosier Energy has a number of questions on the materials provided by EPA on May 1, 2015:

- Will the Federal Plan be a rate-based approach or a mass-based approach?
- If mass-based,
    - What are the mass-based emission goals for each state?
    - How will allowances be assigned to existing units?
    - Please explain the reference to "an abbreviated state plan" on page 14 of the May 14, 2015 presentation.
    - If EPA will using historical data to determine a baseline, which year or years will be used?
    - Will trading of allowances be allowed between states under the Federal Plan and those under a SIP?
    - How does EPA plan to handle the situation if there is a shortfall of allowances—which in turn could require coal units to not operate?
    - Can allowances be carried forward from year to year? If not, when would they expire?
- There are currently no emission controls that can be added to existing coal units that would enable them to meet the proposed rate-based emission goals under the Clean Power Plan. For purposes of the Federal Plan, is EPA contemplating modification of the interim or final goals to a level that coal units can meet, based on achievable heat rate improvements, or will the emission goals remain as proposed under the Clean Power Plan?
    - If EPA does not contemplate modifying the emission goals for coal units, what is the structure of acquiring/trading credits that EPA will include in the Federal Plan?

  - How will the EPA allow states to make provisions for future load growth if it cannot be met with existing resources, and the new source rule limits new fossil generation?

- Please explain the reference to "Complementary measures as part of states' general energy planning process" on page 8 of the May 14, 2015 presentation.

- EPA's proposed 111(d) rule recognizes only wind and solar as renewable resources. The Department of Treasury, in its Clean Renewable Energy Bond allocations, and the State of Indiana, by statute, also recognize landfill gas, coalbed methane and hydropower generation as renewable. Will the Federal Plan recognize allowances or credits from these additional resources which also reduce greenhouse gases?

- Please describe in detail the measurement and verification process that would be required in the determination of allowances or credits from end use energy efficiency measures.

- Describe how the Federal Plan will address remaining useful life of units covered under the proposed 111(d) rule.

The Federal Plan needs to recognize and preserve the remaining useful life of power plants—especially those owned by small fossil electric power generation utilities (as defined by SBA)

- Hoosier Energy supports clean energy. In 2000, our 1,250 MW resource portfolio was 100% coal. Today, our 2,100 MW portfolio is 64% coal, 33% natural gas and 3% renewable. We voluntarily adopted a renewable energy program in 2006 which targets supplying 10% of member requirements from renewable resources by 2025. Similarly, in 2008 we voluntarily adopted a demand-side management/energy efficiency program which targets a 5% reduction in member demand and energy by 2018.

- Hoosier Energy owns two coal-fired generating stations—Ratts Station (250 MW) and Merom Station (1,070 MW). The value of these <u>two</u> facilities represents $780 million or <u>70% of total generation assets</u>.
  - Ratts began operation in 1970. Emission limits assigned to Ratts under EPA's <u>National Ambient Air Quality Standards will preclude Ratts from burning coal in the future. The plant will be retired in 2015</u>. As a not-for-profit

cooperative, Hoosier Energy's members are both our owners and ratepayers. Members are currently paying for the remaining cost of Ratts ($86 million) through rates over 2013-2028.

- Merom began operation in 1982-83 during the Fuel Use Act of 1978—which essentially required all new generation in the United States to be coal capable. The value noted above includes $426 million invested since 2005, primarily at Merom, to comply with numerous air, solid waste and water regulations issued by EPA. These investments and the related financing agreements where based on a remaining useful life of the plant of at least 33 years.

Hoosier Energy's Alternative to EPA's Clean Power Plan

- In comments submitted to EPA on December 1, 2014, Hoosier Energy suggested an alternative to EPA's Clean Power Plan. This alternative framework supports transitioning to a lower-carbon economy in an orderly and cost-effective fashion, recognizes reliability concerns and realistic time horizons, considers the useful life that remains in the valuable generating resources that currently exist, and achieves essentially the same, if not lower, emission levels as the Clean Power Plan in 2030.
- While intended as a complete replacement of the Clean Power Plan, at a minimum the alternative should be recognized as a sub-categorization for small fossil electric generation utilities as defined by the SBA.
- The following discussion of Hoosier Energy's alternative framework is taken from our December 1st comments:

> National concerns over natural gas availability prompted Congress to enact the Energy Supply and Environmental Coordination Act of 1974[1] followed by the Fuel Use Act of 1978 (together, the Acts). The Acts essentially required all new electric generation to be coal capable. The Acts economically prohibited new generation from using natural gas as the primary fuel because of the historically higher fuel cost of natural gas coupled with the additional capital cost required to construct facilities that could run on both coal and natural gas. During the time the Acts were in effect, the nation's electricity needs grew substantially, particularly in rural America. As a result, about 60% of rural electric cooperatives' total

[1] 15 U.S.C. §791, *et seq.*

baseload generation was constructed under the Acts. Although the Acts were repealed in 1987, their influence continued to shape the nation's preference for new baseload coal generation for the next two decades. Subsequent to original construction, billions of dollars have been invested in these coal-fired generating resources for pollution control equipment to meet numerous regulations issued by EPA and to ensure their continued economic and reliable operation for the remainder of their useful life—at least 33 years from the time the most recent investment was made in the unit.

Congress expects states to consider factors such as remaining useful life and stranded investments in determining the standard of performance to apply to each generating unit. The following alternative to the Clean Power Plan does just that:

- States would determine unit-by-unit CO_2 emission limits based upon heat rate improvements that are achievable for each unit, taking into account investments in efficiency improvements that have already been made. Based on all unit-specific information, states would determine the mass-based emission limit applicable to the existing units. CO_2 emissions would be measured on a gross basis, which is consistent with all previous EPA rules.

- On a unit-by-unit basis, states would use the highest of three years (2010, 2011 or 2012) to determine a CO_2 emissions baseline. This acknowledges that utilities were performing significant scheduled outages during this time-frame to install equipment for compliance with other EPA regulations and is consistent with prior EPA rulemakings. Natural gas prices were also at historical lows in 2012 which distorts normal coal generation capacity factors and, therefore, makes the use of 2012 as the sole baseline-year inappropriate.

- Units which came on line prior to 1978 would be phased out in 2030 unless they can meet a valid new source performance standard by that time.

- Units brought on line in 1978 or thereafter[2] would be allowed to operate to 2050 unless they can meet a valid new source performance standard prior to or by that time. A 2050 timeframe recognizes a remaining useful life of 33[3] years for these existing coal units. The timeframe is also consistent with the Department of Energy's timeline that a second generation of carbon capture technology might be developed by 2025 and more advanced and cost effective technologies could be developed beyond 2035.[4]

- While the alternative should provide sufficient time for an orderly and cost-effective transition to a less carbon intensive energy portfolio, FERC, NERC, regional transmission organizations and independent system operators would retain their authority to determine which facilities are needed for grid reliability and to declare facilities that cannot close for that reason, if necessary.

Based on a review of the nation's existing coal units and using a conservative assumption that pre-1978 coal units would be replaced with NGCC units, CO_2 emissions under the alternative are essentially equivalent to the CPP in 2030.

At a minimum, EPA should recognize this alternative as a sub-categorization for small fossil electric power generation utilities as defined by the Small Business Administration. Hoosier would also propose that the CPP or any alternative have language which allows NERC to declare an energy emergency and utilize units as needed to insure reliability.

[2] Another alternative would be to consider any unit that has performed significant upgrades to pollution control equipment from 2003 to present to also be included with the units from 1978 and beyond.
[3] Assumes EPA issues a final rule in 2015 and approves state implementation plans in 2017. To the extent these dates are extended then this timeframe would also be extended as investments in generating units would be continuing.
[4] Energy.gov web site (http://energy.gov/fe/science-innovation/carbon-capture-and-storage-research/carbon-capture-rd) discussing carbon capture R&D and the 2nd and 3rd generation time line for more advanced and cost effective carbon capture.

From:	Leonard Hopkins
To:	Wiggins, Lanelle
Cc:	"Cronmiller, Rae E."; Don Gulley
Subject:	SBAR Comments on 111(d) FIP
Date:	Tuesday, May 26, 2015 4:15:48 PM
Importance:	High

Dear Ms. Wiggins:

Thank you for organizing the Small Business Review panel to discuss EPA's Clean Power Plan Federal Plan (FIP). Southern Illinois Power is extremely concerned about the effect the Clean Power Plan will have on our small Generation & Transmission Cooperative and (especially) the members to whom we provide power.

Our first comment is that we feel this rule is being rushed & the SBREFA process is being rushed forward as well. Under PUBLIC LAW 104–121—MAR. 29, 1996 110 STAT. 867,
SEC. 244. SMALL BUSINESS ADVOCACY REVIEW PANELS,
(b) Prior to publication of an initial regulatory flexibility analysis
which a covered agency is required to conduct by this chapter—
''(1) a covered agency shall notify the Chief Counsel for
Advocacy of the Small Business Administration and provide
the Chief Counsel with information on the potential impacts
of the proposed rule on small entities and the type of small
entities that might be affected;
''(2) not later than 15 days after the date of receipt of
the materials described in paragraph (1), the Chief Counsel
shall identify individuals representative of affected small entities
for the purpose of obtaining advice and recommendations
from those individuals about the potential impacts of the proposed
rule;
''(3) the agency shall convene a review panel for such
rule consisting wholly of full time Federal employees of the
office within the agency responsible for carrying out the proposed
rule, the Office of Information and Regulatory Affairs
within the Office of Management and Budget, and the Chief
Counsel;
''(4) the panel shall review any material the agency has
prepared in connection with this chapter, including any draft
proposed rule, collect advice and recommendations of each
individual small entity representative identified by the agency
after consultation with the Chief Counsel, on issues related
to subsections 603(b), paragraphs (3), (4) and (5) and 603(c)….

The panel could not review a draft rule and comment, because no draft rule was provided by EPA. The fact that no draft rule had been made available gives credence to the fact this rule is being pushed forward in such a manner that small businesses have little time to assess how such a rule **MIGHT** affect them after it is written. It is our opinion that, in order to comply with the letter and spirit of the Public Law denoted above, a draft rule should have been first drafted by EPA, shared with the SBAR panel, and discussed at subsequent meetings with the panel. Without such a draft rule, the SBAR panel is left to surmise what such future rule will have in its contents. We would hope EPA is more interested in getting the rule right rather than quickly. Small companies have small management staffs. That seems obvious, but until it is realized that each of us at SIPC wear many hats, it is difficult to comprehend how unfair such an accelerated schedule for comments is for small businesses!

Southern Illinois Power Cooperative (SIPC) prays that EPA will take into account the costs associated with the building of our generation assets in order to plan for the provision of electric power to our member/owners far into the future.

SIPC has maintained and improved its Unit 4 cyclone boiler (scrubbed) unit and added SCR controls for additional NOX control in 2003.

Also in 2003, SIPC re-powered aging 1963 cyclone boilers with a state-of-the-art Circulating Fluidized Bed boiler. This boiler was considered "Clean Coal Technology" in 2003, and the inherent control system utilizing limestone within the fuel bed makes it inherently inefficient when considering lbs of CO_2 per Mw-hr produced. The bed is kept cooler by the limestone, so steam production for power generation is inefficient.

In 2007, SIPC purchased an 8% share of the new ($5 Billion) Prairie State Generation plant. This plant also utilized clean coal technology, mine mouth fuel supply, and supercritical steam to cleanly generate power.

So, in order to assure the reliability and price of power into the future for our member/owners, SIPC invested hundreds of millions of dollars in these generation assets. Such projects are planned over many years and are expected to last forty to fifty years. It is paramount to SIPC that EPA **NOT** implement a rule that would strand such costly assets and still leave our member/owners with the need to purchase their electrical power while still paying for these assets. This is critical to a small business like SIPC, and it is critical to the member/owners of rural Southern Illinois!! SIPC needs to utilize and pay for these coal generation assets throughout their useful life!!

Small entities would have a more difficult time accessing any CO_2 allowance market than a large utility. As most Coops., SIPC is a not-for-profit organization and does not have large stores of cash. Large entities, especially the two largest entities in Illinois, could control the Illinois CO_2 allowance market and prevent SIPC from access to the market. **IF** EPA pushes a CO_2 allowance market, special care must be taken to allow access for small utilities.

Reliability of electric power is also critical to our member/owners. SIPC has concerns that EPA's 111(b & d) rules, and any FIP that might ensue from such rules, will cause reliability issues within the power markets. At the same time, the cost of power under such rules in our analysis will rise. SIPC stresses that some sort of price and availability safety valve must be put into any such FIP that will allow electricity to continue to be available at a reasonable cost to all citizens of the United States!! We urge EPA to refer to the comments of NRECA on this subject. Indeed SIPC is in support of all of NRECA's comments.

So, in summation, our quick comments on what we were presented are shown below:

1) We should have had a draft rule upon which to comment.
2) EPA should be more concerned with a correct rule for small businesses rather than an expedient rule.
3) Our time to comment was too short.
4) Any such rule must give SIPC (and other Cooperative) member/owners the use of its generation assets, AT A REASONABLE NET GENERATION PRICE, over the course of time to pay for such assets and get full utilization from these investments.
5) EPA should realize that larger utilities can control emission allowance markets (both state and regional), and this places small businesses at an economic disadvantage.

6) Reliability of availability and price of electric power is critical to Cooperatives and SIPC. A "Relief Valve" should be built into any such rule to accommodate this critical issue.

Thank you, again, for the opportunity to comment upon the Clean Power Plan FIP.

Leonard F. Hopkins, P.E.
Vice-President of Fuel, Environmental, & Safety
Southern IL Power Cooperative
11543 Lake of Egypt Road
Marion, IL 62959
(618) 964-2268
Lhopkins@sipower.org

Small Business Advocacy Review (SBAR) Panel on EPA Clean Power Plan – Additional KMU Comments

May 27, 2015

Kansas Municipal Utilities (KMU) appreciates the opportunity to provide supplemental comments as a small entity representative (SER) to the Small Business Advocacy Review (SBAR) panel on the EPA federal plan for regulating greenhouse gas emissions from electric generating units. These comments come in addition to the lengthier formal comments filed by KMU on November 26, 2014 in regards to the Clean Power Plan.

Kansas Municipal Utilities (KMU) is the statewide trade association for municipal electric, natural gas, water, wastewater, stormwater and telecommunications utilities in Kansas. KMU represents 175 cities across Kansas that operate one or more of these types of utilities.

KMU endorses the SBAR comments and materials submitted by the American Public Power Association (APPA) on the federal plan. However, we also wish to provide a little additional "color" to the prospect of compliance with the Clean Power Plan from the nation's prairie communities.

In Kansas, 118 cities own and operate a municipal electric utility. These utilities are often also referred to as public power systems. Three of these 118 public power systems currently operate electric generating units (EGUs) deemed by the Kansas Department of Health & Environment (KDHE) to be affected units under the Clean Power Plan. These include the Kansas City Board of Public Utilities (KCBPU), the City of

Coffeyville, and the City of Winfield. Another 57 municipal electric utilities in the state operate some form of local generation. Most of these municipal power plants utilize reciprocating internal combustion engines (RICE), which are not directly referenced in the proposed Clean Power Plan rule but play a critical role in maintaining reliability in the state's rural areas.

For the purposes of the SBAR panel discussions, a small entity has generally been defined as a community with a population of 50,000 or less. In Kansas, only the largest municipal electric utility – the Kansas City Board of Public Utilities – exceeds that criteria (and not by much, as they serve only 65,000 electric meters).

In fact, the median size of a municipal electric utility in Kansas is one that serves 841 customers. This would be an electric utility similar to the public power system serving the City of St. John, a rural community in central Kansas with 825 electric meters and a population of 1,318 – well under the 50,000 population considered the definition of small. There are 57 public power systems smaller than St. John in Kansas.

These smallest municipal electric utilities are not well situated to make significant changes to comply with a proposed Section 111(d) federal plan. While the small systems are not currently named as affected entities for the Clean Power Plan, KMU remains concerned about ancillary impacts on their operations through power supply cost increases and reliability issues.

KMU encourages the SBAR panel to weight the potential impacts on the very smallest electric utilities and consider a small system exemption. In addition, the agency should take steps to make certain that the federal plan does not inadvertently penalize load-serving entities (LSEs) that do not own or operate electric generating units (EGUs). Should these small non-generating utilities be required to participate in CPP compliance through an emissions reduction mechanism like a renewable portfolio standard or mandated energy efficiency programs, they will be paying the cost to comply twice – once through their power supply costs and secondarily through the cost to provide such programs. The fixed cost to provide such programs to such a small subset of Kansas consumers is also higher than for those utilities or entities with much larger customer bases.

KMU also believes that a proposed federal plan should exempt reciprocating internal combustion engines (RICE) and simple cycle natural gas turbines. In Kansas, these units are used nearly exclusively for demand response and for providing reliability to a historically weak low voltage transmission system. These units do not meaningfully contribute to greenhouse gas emissions in Kansas and would have an inordinate cost to comply, per unit of emission reduction, if included in a federal plan.

KMU stands behind its more formal November Clean Power Plan comments in regards to the compliance timeline, interim goal and reliability safety valve.

KMU respectfully submits that the timeline provided to develop, implement and comply with the proposed rule is woefully inadequate. The complexities inherent to reduce carbon dioxide emissions by the amounts required will take monumental efforts and cooperation between the many stakeholders in Kansas and, perhaps, regionally. KMU requests that the interim goal be eliminated or delayed. At a minimum, KMU requests that EPA extend the timeline for submittal of state plans and for initial compliance with the rule.

In addition, our members continue to believe that the interim goal proposed by EPA is far too aggressive. In fact, Kansas is required to achieve 82 percent of its required reductions by 2020 in order for the state's utilities to meet the interim goal of 1,578 lbs CO_2/MWh. KMU believes that EPA should eliminate the aggressive interim goals and allow each state to determine its own interim reductions and "glide path" toward achieving the final 2030 goal.

At this time, the full impact of the proposed rule on the reliability of the electric grid in Kansas and the Southwest Power Pool (SPP) region cannot be definitively calculated. However, it is of crucial importance that EPA study and take into account the potential effect of the proposed rule on the reliability of the electric system and the overall impact on residential, commercial and industrial customers. A Reliability Safety Valve (RSV) is an appropriate measure that should be included in the rule as a means of avoiding potential reliability events in Kansas and the Midwest.

In conclusion, Kansas Municipal Utilities very much appreciates the opportunity to provide comments on the proposed Section 111(d) federal plan. Please feel free to contact me at 620.241.1423 or email chansen@kmunet.org with any questions or for additional information.

Colin Hansen
Executive Director
Kansas Municipal Utilities
May 27, 2015

May 28, 2015

SUBMITTED VIA ELECTRONIC MAIL

Ms. Lanelle Wiggins
RFA/SBREFA Team Leader
U.S. Environmental Protection Agency
Office of Policy (1803A)
1200 Pennsylvania Avenue, NW
Washington, DC 20460
wiggins.lanelle@epa.gov

Re: Small Business Review Panel Outreach on the Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or before January 8, 2014
Comments of San Miguel Electric Cooperative, Inc.

Members of the Small Business Advocacy Review Panel:

San Miguel Electric Cooperative, Inc. ("San Miguel") thanks the Small Business Advocacy Review ("SBAR") Panel ("Panel") for selecting San Miguel to participate as a Small Entity Representative ("SER") in the U.S. Environmental Protection Agency's ("EPA") development of a federal plan ("Federal Plan") to implement the Clean Power Plan ("CPP").[1]

San Miguel's comments will be covered under the following general headings:

I. Introduction
II. Concerns With the Small Business Advocacy Review Process
III. Special Considerations for Small Business Entities' Ability to Comply with a Federal Plan
IV. Additional Comments on Specific Issues Arising in SBAR Panel Process.

As an initial disclaimer, nothing in this comment or any other statement made by San Miguel as an SER and in the SBAR Panel process should be construed as an endorsement of EPA's actions related to the CPP or as a contradiction of written comments previously filed by San Miguel or the Gulf Coast Lignite Coalition ("GCLC"), of which San Miguel is a member.[2] San Miguel has consistently opposed the CPP, EPA's authority to

---

[1] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule, 79 Fed. Reg. 34,830, 34,887 (June 18, 2014).
[2] *See* Comments of the Gulf Coast Lignite Coalition on the Clean Power Plan, Docket Id No. EPA-HQ-OAR-2013-0602-23394.

promulgate the CPP or develop a Federal Plan to implement the CPP, and the likely potential requirements of a Federal Plan. However, as an active participant in this SBAR Panel and understanding that EPA intends to finalize the CPP and develop a Federal Plan to impose the CPP requirements on states that do not implement a State Implementation Plan (SIP), San Miguel submits the following comments to the Panel on the EPA CPP Federal Plan.

I. INTRODUCTION

San Miguel is a rural electric Generation and Transmission ("G&T") Cooperative formed to provide electric generation for its member cooperatives and residents of South Central Texas. As a not-for-profit cooperative, San Miguel is fully owned by its consumer members, a majority of which are rural residential users. As such, the cost of electricity is of great concern to San Miguel and its consumer members.

The principal business of San Miguel is the production of electricity. San Miguel operates only one power generation facility, which includes one lignite-fired power plant and one lignite mine in Atascosa County, Texas. This lignite-fired power plant has a net capacity of 391 megawatts and is a base load unit. Construction of the power plant began in 1979, and commercial operation began in 1982. Barring the effect of the CPP or other EPA rules, the San Miguel plant is anticipated to operate until 2037. As a small business rural G&T cooperative, San Miguel has relied primarily on financing through the U.S. Department of Agriculture's ("USDA") Rural Utility Service ("RUS").

The generating unit's sole source of fuel is lignite provided by the co-located lignite mine owned by San Miguel. This one lignite-fired unit comprises 100% of SMEC's generating capacity and average historic yearly output of approximately 2.9 million megawatt hours. San Miguel is a small business as defined by the Federal Energy Regulatory Commission ("FERC") and the Small Business Regulatory Enforcement Fairness Act ("SBREFA") regulations.[3]

San Miguel has a significant interest in the outcome of this rulemaking. San Miguel's lignite-fired electric generating facility is a major source of electrical generation to our member cooperatives, under long term wholesale power contracts for 100% of the generation of the San Miguel power plant. Being a not-for-profit entity, San Miguel will be forced to pass along to its consumer-owners all costs of meeting any new requirements that may result from the implementation of the CPP and the imposition of a Federal Plan.

As a member-owned electricity supplier, San Miguel understands that reliable, affordable electricity has been one of the key drivers of economic growth and prosperity in this country. This fact must not be forgotten as the EPA makes decisions on whether and how to regulate greenhouse gas emissions, specifically carbon dioxide, ("CO_2") from fossil-fired electric generating units under the CPP.

---

[3] *See* 13 CFR § 121.201.

II. CONCERNS WITH THE SMALL BUSINESS ADVOCACY REVIEW PROCESS

San Miguel is very concerned with this SBAR Panel review and comment process, based on two primary reasons.

First, San Miguel believes that any comments that can be filed by a SER at this point will inevitably be incomplete and insufficient. EPA did not provide usable information or data in a sufficient form that would assist the SERs in assessing the potential impact of this rulemaking and a potential Federal Plan. Without the necessary information or options, SERs cannot be expected to identify reasonable regulatory alternatives, to the extent that any may exist.

Second, developing new source performance standards ("NSPS") for CO_2 emissions involves complexities heretofore not encountered in the NSPS context. Unlike other emissions regulated under the Clean Air Act ("CAA"), there are no viable emissions control technologies applicable to reducing CO_2, the main GHG component in Electric Generating Unit ("EGU") emissions. Therefore, in the CPP, EPA has proposed regulations on the entire electricity grid as part of its best systems of emissions reduction ("BSER") criteria, including: energy efficiency improvements that will not be obtainable at numerous coal-fired power plants, particularly in deregulated markets like the one San Miguel operates in; a shift in energy production from the very stable coal-fired generating units to natural gas generation; massive expansions of renewable energy production; and limitations on end-user consumption of electricity. Unfortunately, the SERs have yet to see a proposal by EPA on options it may be considering to actually implement these criteria in the form of a Federal Plan. While San Miguel appreciates the opportunity to submit early comments and participate prior to the release and distribution of a federal plan, the extent of SER comments is inherently limited. It is an impractical and unrealistic expectation on SERs to comment, on literally, an infinite degree of potential limitations on its industry; it is also contrary to the explicit requirements that EPA present regulatory options for review by the panel, including the provision of a draft rule proposal.[4] Therefore, prior to the release of the Federal Plan, an additional meeting must be held by the SBAR Panel to receive comments on any draft Federal Plan.

[4] *See* 5 USC §609, generally, and 5 USC 609(b)(4), which states: "the panel shall review any material the agency has prepared in connection with this chapter, including any draft proposed rule, collect advice and recommendations of each individual small entity representative identified by the agency after consultation with the Chief Counsel, on issues related to subsections 603(b), paragraphs (3), (4) and (5) and 603(c)."

III. SPECIAL CONSIDERATIONS FOR SMALL BUSINESS ENTITIES' ABILITY TO COMPLY WITH A FEDERAL PLAN

In the CPP, EPA expressly invited comments on "whether there are special considerations affecting small rural cooperative or municipal utilities that might merit adjustments to this proposal and, if so, possible adjustments that should be considered." [5] Being a small business, San Miguel does not have the financial resources and fleet size that large utilities possess to implement changes and adjust resources to meet the requirements of the CPP. San Miguel believes EPA needs to provide flexibility to small businesses and cooperatives as provided in Section 111(d) of the CAA, "in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[6] EPA regulations further require it to allow states to consider "unreasonable cost of control resulting from plant age, location, or basic process design," "physical impossibility of installing necessary control equipment," and "other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable."[7] EPA must consider and apply the same standards and limitations on its development of a Federal Plan, and heed the concerns, warnings, and recommendations provided by impacted electric utilities, particularly small business G&T cooperatives like San Miguel, in its development of a Federal Plan.

A. EPA must take into consideration the useful life of an impacted EGU in the development of any Federal Plan.

Section 111(d)(1)(B) of the CAA states that Section 111(d) regulations "**<u>shall permit the State</u>** in applying a standard of performance to any particular source under a plan submitted under this paragraph **<u>to take into consideration</u>**, among other factors, the **<u>remaining useful life of the existing source</u>** to which such standard applies."[8] While there are numerous factors that should be considered, many of which are addressed in this comment, the one specifically referenced in the statute is "remaining useful life." The statute refers to the "States" considering "remaining useful life," but since the EPA would step into the shoes of states in order to impose a Federal Plan, the same requirement applies to the EPA.

EPA apparently believes that the San Miguel unit will be retired in its base-case analysis contained in the CPP docket (i.e. prior to even considering the impact of the CPP).9 In fact, although the burdens of new rules have been great, San Miguel has undertaken aggressive action to ensure compliance with the Cross-State Air Pollution Rule

[5] Clean Power Plan Proposal, 79 Fed. Reg. at 34,887.
[6] 42 U.S.C. 7411(d)(1).
[7] 40 C.F.R. 60.24(f).
[8] 42 USC § 7411(d)(1)(B).
[9] *See* EPA IPM, Proposed Clean Power Plan_Option 1 State_RPE File; Parsed File – Option 1, State, 2025.

("CSAPR") and the Mercury and Air Toxics Standards ("MATS") Rule) and other pending regulatory actions and expects to be able to legally operate for, literally, decades to come.
San Miguel operates only one unit, which means that as opposed to larger utilities with numerous generating units and technologies, the lignite-fired power plant in Atascosa County is San Miguel's only resource. It is critical, then, that this unit is allowed to remain in operation. To force the shutdown of this unit prior to the end of its remaining useful life would put incredible strain and cost burdens on San Miguel's member cooperatives. The facility is too important to San Miguel's member cooperatives, there has been simply too much invested in the facility, and there is too much RUS financing to be returned, for the facility to be forced to shutdown prior to the end of its useful life. San Miguel has performed two independent studies on the useful life of the San Miguel Electric Generating unit both have stated: the plant has an operating life of no less than 55 years since its first full year of commercial operation, which was 1982. Thus 2037 have been used as the payoff date for all financing of the plant.

The San Miguel power plant's significant remaining useful life must be taken into account in the development of a Federal Plan – specifically, the imposition of emissions limits or emissions restrictions. Any proposed emissions limit, whether it be rate-based or mass-based (see the discussion in Section II.C. below), must be sufficiently flexible to allow for the continued operation of the San Miguel facility. EPA also has the authority to grant variances from emissions limits due to economic hardship or apply less-stringent limitations when economic factors demand. Small business entities, and specifically San Miguel, are the very types of entities contemplated to receive variances and/or accommodations.

If EPA were to set overly stringent unit-specific emission limits and no reasonable alternatives for compliance in its Federal Plan for the San Miguel power plant, EPA would violate the CAA requirements that EPA consider the useful life of impacted units and would further violate the requirement that the standard of performance take into account the cost of achieving emissions reductions and any nonair quality health and environmental impact and energy requirements.[10]

Finally, a unit-specific emissions limit or other emissions restriction cannot force the retirement of the San Miguel power plant without any explicit or implicit authority to do so. This would constitute an unlawful taking of San Miguel's property.

B. EGUs Must be Provide the Choice of Complying with Either Rate-Based or Mass-Based Emissions limits.

The CPP Proposal provides states the option of using rate-based or mass-based emissions limitations. We believe that this same choice should be provided to small businesses impacted by a Federal Plan; EGUs must be provided the choice of using either a rate- or

[10] 42 USC § 7411(a)(1).

mass-based limitation. So far in this SBAR Panel process, EPA has indicated that emissions limitations and allocations would be on an EGU-by-EGU basis, but did not provide any other information such as how rates or mass would be established. Thus, it is unclear, without knowing how these rates or mass-based systems will be developed, known which method would be best. Further, once established, some units may be able to comply with the rule better under a rate-based system, while others, would operate better under a mass-based system. Given the choice of complying with a rate or mass-based limit, a small business operating a coal fired EGU could determine how to operate in the best and most efficient way possible. This could include, but is certainly not limited to, determining whether load should be modified at certain times during the year or whether credits should be purchased.

C. Any Federal Plan Must Include a Lignite Subcategory.

EPA, in the CPP, makes no attempt to distinguish between lignite and other coal-fired power plants and, therefore, does not contemplate the unique characteristics that lignite-fired EGUs possess or the challenges that these EGUs have in complying with a rule without a separate lignite-fired EGU subcategory. This should be rectified in any Federal Plan imposing limitations on lignite-fired power plants.

Lignite-fired power plants are technologically and operationally distinct from traditional coal-fired power plants and include different design elements that warrant and require a separate subcategory within the overarching coal category. This lignite subcategory should include more relaxed emissions limits and standards.

The physical and chemical characteristics of lignite demand subcategorization. Lignite has a lower heat-value than other types of coal, resulting in the need to combust additional fuel in order to meet comparable generation amounts. Further, the physical and chemical composition of lignite also typically requires larger, more energy intensive, control technologies than other coal-fired units. The increased parasitic load of these technologies inherently increase GHG emissions and decrease performance capabilities of these units as compared to other coal-fired power plants.

In addition, lignite EGUs are almost always at mine-mouth power plants that are co-located with the mines that supply their coal. This is the case with the San Miguel plant as our associated mine is immediately adjacent to the power plant - the mine and plant are inextricably linked. Imposing limitations that would require San Miguel to comply with the emissions standards of non-lignite units is not feasible. Fuel switching is impossible, as San Miguel does not possess the infrastructure necessary to do so, whether it is rail lines to import alternative coal, or pipelines to transport natural gas.

EPA, as recently as the MATS Rule, established a subcategory for lignite within the larger coal subcategory, not only because of the chemical composition of the fuel source, but also because lignite units are "universally constructed 'at or near' a mine containing" lignite with designated and narrowly limited conveyance mechanisms to transport lignite from the mine to the power plant.[11] There is no difference in this instance.

If EPA does not provide a subcategory for all lignite units, or unit-specific elevated emissions limits for lignite units in a Federal Plan, this may require San Miguel to shut down, forfeiting use of the extremely valuable lignite that exists in the reserves under south Texas, the affordable power that it is able to generate, and though a small business, the countless, and compared to the rest of the Atascosa County, well-paying and stable jobs for the people of the county.

D. EPA Must Explicitly State that Actions Taken to Comply with the CPP and/or a Federal Plan, including Heat-Rate Improvements Do Not Trigger New Source Review Requirements.

EPA has failed to appropriately protect coal-fired EGUs implementing changes that could be interpreted as triggering new source review ("NSR") permitting requirements. One particular point of risk for these units is heat rate improvements involving equipment replacements or upgrades; these may be required under Block 1 of the BSER model and are also a conceivable compliance requirements for unit-specific limitations in a Federal Plan. Rather than merely seeking comment on whether states will be allowed to design programs at stated in the CPP,[12] EPA must take the opportunity in the CPP rulemaking and in the Federal Plan to specifically find that these types of changes do not constitute modifications and must further institute a policy that EPA will not seek enforcement actions for these types of changes. EPA could classify heat rate improvements as routine maintenance, exempt from NSR requirements. This type of relief is necessary, because the threat of NSR permitting can significantly limit the availability of heat rate improvements that can be pursued by existing power plants. With this risk of potential enforcement action or suits brought to compel enforcement, there will be a chilling effect amongst operators reluctant to trigger additional NSR burdens. Therefore, in order to ensure that heat rate improvements continue to be a viable option under the CPP and in the Federal Plan, EPA must take steps to remove this chilling affect and clearly state that heat rate improvement activities, or any activities carried out for the express purpose of reducing CO_2 emissions, do not trigger NSR permitting requirements.

E. CO_2 Emission Impacts Due to Recently Installed Environmental Controls Should Be Excluded from Emissions Limitation Burdens.

San Miguel has aggressively pursued various compliance measures – including the installation of control technologies – to comply with EPA's recent rulemakings. For example, San Miguel installed a selective non-catalytic reduction ("SNCR") device at the facility to reduce nitrogen oxide ("NOx") emissions as a means toward complying with CSAPR. The result of installing an additional add-on control however, was an inevitable

---

[11] MATS Rule, 77 Fed. Reg. at 9379. EPA used the term "low rank virgin coal" with a heat-input value of 8,300 Btu/lb, which is almost exclusively lignite.

[12] Clean Power Plan Proposal at 34,928 – 34,929.

increase in the parasitic load at the facility in order to operate the device and the resulting impact of increased CO_2 emissions. The full impact of this installation was not in effect until 2015, the first compliance year of CSAPR. Therefore, EPA's CPP is using data (2012) that predates and does not incorporate the increased CO2 rate that the SNCR, and other control technologies implemented after 2012 have on CO_2 emissions. Not only *should* EPA zero out the increased CO2 rate due to the new environmental rules implementation, it is required to do so under Section 111(d) of the CAA which requires EPA to "tak[e] into account…any…environmental impact and energy requirements" as part of its standard of performance determination, and as part of the development of its FIP.

F. Any Federal Plan Must Provide Appropriate Deference and Variance to those Targeted EGUs Which Commenced Construction During the Implementation Powerplant and Industrial Fuel Use Act of 1978

During the late 1970s and early-to-mid 1980s, the energy crisis and, ultimately, the Powerplant and Industrial Fuel Use Act ("Fuel Use Act") drove power plant operators to pursue coal-fired generation .[13] This was particularly true for electric cooperatives that did not have the resources to pursue nuclear power - making coal-fired generation the only viable option.

For EPA to now propose the CPP, and potentially impose requirements via its Federal Plan, is effectively a bait and switch. Not only did the Federal government functionally require the construction of coal units, through funding by the RUS, it actively promoted this construction. EPA's development of a Federal Plan that undermines, or completely devalues, the San Miguel plant is an abuse of the agency's powers, fundamentally violates the separation of powers doctrine, and, arguably, takings protections of the U.S Constitution.

G. Federal Plans Should Include a Reliability Safety Valve.

The North American Electric Reliability Corporation ("NERC"), Southwest Power Pool ("SPP"), ERCOT, and others all call for a reliability safety valve. This is a necessary component of any Federal Plan (or State Plan) pursued under the CPP. However, a safety valve cannot simply be a uniform extension in compliance dates or other one-time measure. Given the incredible complexity of the rule, there are numerous variables that can affect compliance dates and impact reliability or could trigger the need for regulatory relief. For example, potential triggering events include unforeseen changes in the availability and operability of electric generating resources, fuel shortages, extreme weather events, changes in laws, or the other countless events that could impact electric reliability. Therefore, any reliability safety valve must be dynamic.

Various proposals have been put forward to design and implement a reliability safety valve. This includes a joint proposal by NRECA and the American Public Power

---

[13] *See* 42 USC §§ 8302(a)(8) & 8311(a).

Association ("APPA"), which was outlined in the NRECA comment submitted as part of the SBAR Panel Process. San Miguel believes that this proposal goes above and beyond what is required in a safety valve, imposing a structure and limitations far more burdensome than what should be required to demonstrate the need to continue operating to maintain reliability. With that caveat, San Miguel supports the NRECA/APPA joint proposal

H. Emissions Limits Must Be Able to Be Met Within the Fence.

Before leaving the topic of special considerations for small entities, San Miguel believes the "outside the fence" issue warrants discussion. The plain language of Section 111(d) of the Clean Air Act makes it clear that a standard of performance should apply to an "existing source" of an air pollutant[14] and, as defined, a "stationary source" is "any building, structure, facility, or installation which emits or may emit an air pollutant."[15] The language does not refer to "groups of existing sources" or the "markets related to an existing source," but rather, requires that standards apply to individual "existing sources" in isolation. This is otherwise known as basing the standards on what exists and occurs within the fence of the facility and not looking beyond it. EPA's implementing regulations support this position. For example, EPA's regulations state that in order to demonstrate "increments of progress" toward compliance with a standard of performance, there are steps "which must be taken by an owner or operator of a designated facility."[16] Given these regulations, interpretive case law, and CAA-imposed limitations, including that EPA must take into account "the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements,"[17] it is incumbent upon EPA to establish limits in its Federal Plan that individual units can meet within its fence.

EPA's Block 1, as proposed, assumes a coal-fired power plant heat rate improvements of 6% (or in the alternative 4%) is not obtainable. EPA in the CPP concluded that 4% of heat rate improvement can be achieved through best practices and an additional 2% can be achieved by equipment upgrades.[18] However, there is no way to guarantee or even support that these types of improvements can be achieved at every, or even most, units.

There are numerous reasons that this is a flawed assumption and are addressed in much greater detail in GCLC's comment on the CPP proposal[19] but to summarize those points as they are applied to San Miguel, it is extremely unlikely, if not impossible, for San

[14] 42 USC § 7411(d)(1)(A).

[15] 42 USC § 7411(a)(3).

[16] 40 C.F.R. § 60.21(h).

[17] 42 USC § 7411(a)(1).

[18] GHG Abatement Measures Technical Support Document for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units, 2-34 (June 10, 2014).

[19] *See* Comments of the Gulf Coast Lignite Coalition on the Clean Power Plan Proposal at 25-27.

Miguel to achieve this heat rate improvement. In order to comply with the CSAPR, MATS, and other threatened rules, San Miguel has had to extract as much efficiency as possible from its boiler. Further, San Miguel operates in the Electric Reliability Council of Texas ("ERCOT") market, which is a deregulated electricity market with competitive electricity prices. It is incumbent upon San Miguel to operate as efficiently as possible in order maintain competitive electric prices and ensure that its power is purchased. Ultimately, EPA must impose an emissions limitation that accounts for the efficiency already achieved at the individual unit (e.g. San Miguel), some of which has been achieved in just the last few years – rather than attempting to look fleet or industry wide. Further complicating compliance at the San Miguel facility is that San Miguel's sole generation resource is a single lignite-fired EGU. Without the ability to manipulate dispatch from other generating resources, which could reduce the impacts of a Federal Plan and provide additional flexibility, San Miguel must rely entirely on what it can achieve within the fence. Therefore, further flexibility and less burdensome requirements should be provided to single-unit small businesses, such as San Miguel.

I. Compliance Timelines Must be Shifted and the Interim Compliance Deadline Should be Eliminated

In addition to the addressing strenuousness of the limit, EPA must also adjust the timeline for compliance. The CPP proposes CO_2 emissions rates for Texas of 853 lbs/MWh from 2020-2029 (interim) and 791 lbs/MWh in 2030 and after (final); EPA has calculated a baseline CO_2 emissions rate for Texas of 1,284 lbs/MWh. This is a reduction target of 33.6%, on average, from 2020-2029, and 38.4% from 2030, onward. While the targets themselves for the state are so burdensome that they simply cannot be met, EPA must also recognize the incredibly small difference between these two targets and the effect that it has on the compliance. The result of this timeline and tiny difference between the two targets, is that the compliance date is effectively 2020, not 2030. Further, states cannot delay in compliance to later in the interim period, because to do so would create a "bow wave" of burdens that would only magnify the already-crippling compliance impact of the CPP. The same arguments apply to individual unit compliance.

Small entities like San Miguel are challenged in many unique ways by the proposed rule, but one of the most significant is the fact that the compliance date comes so fast and requires so much, that there is no legitimate way for a small entity with limited resources and options to respond so quickly to such a dramatic compliance requirement. So, not only must EPA fundamentally revisit its "outside-the-fence" standard derivation assumptions, it must ensure that its FIP does not follow the model of the proposed rule's interim limits and compliance deadlines need to provide significant additional time for small entities that have neither the resources nor the options to respond in the dramatic way and short timeframe contemplated by the proposed rule.

IV. ADDITIONAL COMMENTS ON SPECIFIC ISSUES ARISING IN SBAR PANEL PROCESS.

There have been numerous discussions on various topics throughout the SBAR Panel process. While many of those topics are addressed above, San Miguel would also like to quickly comment on a few additional issues and concerns. These comments are broadly applicable to all entities impacted by the CPP, but at a minimum, should at least be applied to the small business entities that are targeted by the CPP and a Federal Plan.

1. Baseline for a unit's CO_2 emissions should not be based on a single operational year; in the CPP, this was 2012. Rather, it should be based on an average of the <u>three</u> highest emissions years for the past <u>five</u> years. This would be consistent with other rules, including CSAPR, which took the same approach to establishing an emissions baseline. One year is simply not enough time to accurately establish a baseline.

2. Compliance should be based on a multi-year average of emissions, and not limited to one particular year. An averaging period over five years would allow for fluctuations in demand. In Texas, this is particularly relevant during periods of drought or consecutive summers climate; in Texas, this includes higher-than-normal summer temperatures leading to increased electricity demand. This would also provide additional flexibility for small business entities that have no other means to secure this flexibility (e.g. shifting operations between separate, though commonly owned, EGUs). Further, this is in line with the global characteristics of CO_2 and the long-term goals of the CPP.

3. Emissions credits/allowances should not expire and a utility should able to collect credits/allowances. For many of the same reasons that a multi-year averaging period should be used, preventing credits from expiring will provide additional flexibility to regulated entities. In line with this non-expiring nature of the credits/allowances, credits/allowances should also not be allowed to be intentionally retired by third parties. Third parties have at times purchased credits/allowances for the explicit purpose of retiring those credits. This distorts markets and reduces the functionality and cost-effectiveness of a credit/allowance system. Further, individual units should not be shutdown, without the opportunity to avail themselves of credit/allowance mechanisms that provide additional time to the unit to reach compliance rather than being forced to shut down.

4. EPA should develop a minimum utilization as a backdrop against a mandated shutdown. This could be designed as a minimal level necessary for the unit to supply the electric purchase agreements and contracts previously entered into, as well as ensure reliability.

San Miguel would like to once again thank the SBAR Panel for selecting San Miguel as a SER on this very important industry regulation. We encourage the Panel to give further consideration in scheduling an additional Panel meeting so that a final draft rule might be available for review and comment and, if not, once the EPA has finalized rulemaking and has released a Federal Plan.

If you have any questions concerning these comments please contact me directly.

Sincerely,

Joseph G. Eutizi
Engineering Manager
San Miguel Electric Cooperative, Inc.
830-784-3411 ext. 226
jeutizi@smeci.net

13499896v.3

IMEA
IPEA • IMUA
3400 CONIFER DRIVE, SPRINGFIELD, IL 62711
217-789-4632 / FAX 217-789-4642

Comments from the Illinois Municipal Electric Agency and Illinois Municipal Utilities Association to the Small Business Advocacy Review Panel on the Impacts of the Clean Power Plan on Small Entities

May 28, 2015

On behalf of our members and all the municipally operated electric systems in the state of Illinois, we at the Illinois Municipal Electric Agency (IMEA) and Illinois Municipal Utilities Association (IMUA) appreciate the opportunity we have had to participate in the Small Business Advocacy Review (SBAR) Panel on the Environmental Protection Agency's (EPA) Federal Plan for Regulating Greenhouse Gas Emissions from Electric Generating Units (EGU), otherwise known as the Clean Power Plan (CPP). IMEA has previously filed comments (in November, 2014) outlining our concerns with EPA's Proposed Rule under section 111(d) of the Clean Air Act (CAA) to reduce emissions of carbon dioxide (CO_2) from fossil fuel-fired EGUs.

Who we are: There are 42 municipally operated electric systems in Illinois and 40 of those are of 50,000 in population or fewer. IMUA is a trade organization that represents the interests of 41 of the 42 municipal systems. IMEA is a joint action agency that aggregates the power supply needs of 32 of the state's municipal electric systems and one electric cooperative and provides them with wholesale power and energy that the systems resell to their end-use customers. Therefore, not only are these units of government small entities themselves, but they are the home to numerous classic small businesses, upon whom they depend for the jobs and revenues that underpin government operations. Conversely, these cafes, car dealerships, lawn care businesses, farm implement dealers and the myriad of other businesses depend upon a reliable power supply with stable pricing to permit them to operate. Further, the municipal systems operate on a not-for-profit basis. All the costs we incur have to be offset by revenue collected from the members' customers, many of which, as noted above, are small businesses.

We, along with most of the other participants in the electric utility industry in Illinois, have been working diligently with the Illinois EPA since the release of the CPP to develop the structure of a State Plan. We continue to be involved in that process. However, in as much as the SBAR Panel is to offer its recommendations on the contents of Federal Plan, we offer this background and our suggestions.

Illinois and the CPP: The Illinois EPA's efforts to craft a State Plan has been complicated by the fact that Illinois is a deregulated state and operates in two regional transmission organizations (PJM and MISO). As such, generation in the state is only compensated to the extent that the capacity auctions in each RTO provides sufficient revenue for their continued operation and maintenance. It should be noted that while the investor-owned systems in Illinois are no longer vertically integrated (as a result of the 1997 law mandating retail choice for their customers), the Illinois municipal systems and cooperatives continue to be vertically integrated and provide their own capacity and energy to the associated load serving entities, that is, their members. This fact is one reason that IMEA has invested in, and is obligated to pay for, a variety of power generation facilities.

In addition, there is the question of keeping the existing Illinois-based, nuclear-fueled power plants in the state functioning. Exelon (the owner) argues that they are not receiving sufficient revenue from the auction to continue operation. Absent their carbon free output, the path to compliance in Illinois is much steeper. Discussions about a new revenue stream for the plants is ongoing at the state capitol. But this has now become mingled with a recent significant increase in capacity prices in MISO, which jumped by a factor of 9 (from $.51/kW month to $4.56kW/month) for the year 2015/2016 beginning in June.

These increases have been driven, in part, by concerns over the future adequacy of generation capacity in MISO (and therefore in Illinois). The impact of this cost increase on the customers of Ameren (the investor-owned system that serves in the MISO region) has become a political matter, with calls to investigate the auction.

Our affected investments: IMEA is currently part owner of two coal-fired generating facilities, as noted in our comments to US EPA on the Clean Power Plan. We own on behalf of our members a 15.17% portion of the Prairie State facility (two, 800 MW supercritical units) located in southern Illinois that went online in 2012. It uses the most advanced coal-fired technology widely available and as such is already MATS compliant. We also own a portion of the Louisville Gas & Electric Trimble County Units located northeast of Louisville, KY on the Ohio River - 12.12% of Unit 1 (511 MW net output) and 12.12% of Unit 2 (760 MW net output). Unit 2 is also a supercritical unit and MATS compliant. Unit 1, however, is a conventional pulverized coal-fired power plant and will require the installation of a bag house, which is currently being installed and will be in service by the end of 2015. Total cost of our part of the project is $18 million. The capital was raised by the sale of tax-exempt bonds and is recovered though the inclusion of the expense in our wholesale cost of power to the members. With the exception of Trimble County Unit 1, all these resources are only a few years old and have a minimum useful life of at least 40 years. And as noted here, Trimble County Unit 1 is even now being retrofitted at considerable expense to meet the MATS requirements that will extend its useful life as well.

As to emission levels, these units (with the exception of Trimble Unit 1) represent the latest and best available commercial technology for coal-fired EGUs. As such, their emissions of CO_2 are approximately 2,000 lbs/MWh. The Illinois state coal-fleet average (according to IEPA) is 2,334 lbs/MWh. We note that by IEPA's own calculations, a 6% efficiency improvement based on the fleet average would result in an emission level of 2,194 lbs/MWh. Therefore, our supercritical units already operate at an efficiency level that exceeds the Block 1 goal.

As to the economics of our power generation purchases, they were predicated upon the units being base-loaded to their maximum ability, ideally in the 80% or greater capacity factor range. Our total investment in the four units in which we share ownership is approximately $1.16 billion, secured through a variety of primarily tax-exempt bond issues, the terms of which vary but extend to 2035. Those moneys are owed to our bond holders whether the plants run at full load or any percentage below full load. In the case of reduced plant output (which could be triggered by Building Block 2), fixed costs are divided among fewer MWhs of sales, resulting in an increase in cost to our customers. While it is difficult to quantify the economic impacts of the displacement of our generation, such displacement will result in not only direct increased costs to our units, but the need to buy energy and perhaps even capacity from other sources to replace that which we were providing from our own resources. This will result in a double penalty and yet another layer of cost. (A very quick back of the envelope calculation based upon a reduction in capacity factor from 80% to 50% for the EGUs noted here indicates an increase in the delivered cost to our members of between 10% and 15%.)

In addition, our engineering staff advises that supercritical units have great difficulty in ramping up and down to follow load and are best suited for steady state, base-load operations. Ramping not only triggers the economic issues discussed above, but creates inefficiencies that increase other criteria pollutant emissions. Given these facts, we are particularly concerned about the Block 2 concept within the CPP, which would displace existing coal-fired generation with natural gas-fired capacity.

Conclusions: If Illinois EPA's efforts are successful we may not be subject to a Federal Plan. In the event Illinois is not successful in providing a State Plan, any FP should provide the largest selection of opportunities for entities such as ours to mitigate the costs of compliance. To that end:

We support the comments submitted by the American Public Power Association to the SBAR Panel, in particular, we commend their suggestion on alternative emission reduction credits and a credit safety valve: As of today, there are no established trading programs in Illinois for carbon dioxide. It is our understanding that Illinois EPA is, as a part of its planning, examining the concept of trading some form of CO2 credits. But whether that is to be a state-only or a multi-state program, or if the program is instituted at all, is unknown and dependent upon the shape the CPP takes when final. Any FP should take into account that states may institute either mass-based or rate-based compliance standards and that allowances or credits need to be interchangeable and transferable to the maximum extent possible. Such credits and allowances should also include a cost cap.

Institute a reliability safety valve: There is no authority in Illinois to require the construction of new generation to fill any void left by retirements that result from the CPP. The Illinois Commerce Commission lost that authority with the passage of industry restucturing legislation in 1997, as referenced earlier. Thus, Illinois' future capacity needs are met entirely by entities willing to build genration based on the return they will receive in the capacity markets. To date, the cost of capacity in both MISO and PJM has been insufficient to incent new generation. The threat of CPP-triggered retirements to overall system reliability is real and there should be a role for the North American Electric Reliablity Corporation in reveiwing an FP to ensure it does not endanger reliability as well as some off ramp or safety valve to suspend the rule in instances of reliability issues.

Delay or dilute the interim goals: Imposition in 2020 of the interim goals in Illinois will create major compliance issues. IEPA notes that the 2020 goal (1,366 lbs/MWh of CO_2) is a reduction of 28% in emissions from the adjusted baseline of 1,895 lbs/MWh of CO_2, while the final goal of 1,271 lbs/MWh is a 33% reduction from the adjusted baseline. That 2020 reduction goal is set too low and comes too quickly. The interim compliance date should be pushed back or the interim goal number adjusted upward significantly to avoid this problem.

Exclude RICE and NGSC units: We believe the CPP does not intend to capture either reciprocating internal combustion engines (RICE) or simple cycle natural gas turbines (NGSC). The FP should clearly reflect that fact.

Provide flexibility in setting an emission baseline: For affected units that were not fully online during the baseline year or years, states need the flexibility include a proxy for their emissions so they are dealt with equitably.

Exempt units that are already 6% more efficient than the state fleet average: If an affected EGU demonstrates that it operates at a heat rate that is 6% more efficient than the state fleet average (as per the goals in Block 1), that unit should be exempt from the requirements of the rule.

Thank you again for allowing us to participate in this process.

Regards,

Phillip "Doc" Mueller
Senior VP – Government Affairs and Management Services
Illinois Municipal Electric Agency/Illinois Municipal Utilities Association
3400 Conifer Drive
Springfield, IL 62711
217-789-4632

LS Power Development, LLC
One Tower Center, 21st Floor
East Brunswick, NJ 08816
Phone (732) 249-6750 Fax (732) 249-7290

May 28, 2015

VIA Email

Lanelle Bembenek Wiggins
RFA/SBREFA Team Leader
US EPA - Office of Policy (1803A)
1200 Pennsylvania Ave. NW
Washington, DC 20460

Re: Federal Plan Requirements for Greenhouse Gas Emission from Electric Utility Generating Units Constructed on or Before January 8, 2014

Dear Ms. Wiggins:

LS Power Development, LLC ("LS Power") respectfully submits these comments in connection with the Small Business Advocacy Review Panel's participation in EPA's upcoming rulemaking "Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014" (the "Federal Plan"). LS Power appreciates the opportunity to provide input on the proposed Federal Plan aimed at establishing standards consistent with the Best System of Emission Reductions under Sec. 111(d) of the Clean Air Act and prescribing compliance requirements for covered sources.

Founded in 1990, LS Power is an independent power company whose employees provide development, construction management and ownership services for power generation and electric transmission infrastructure projects and investments throughout the United States. Since its inception, LS Power employees have been involved in the development, construction, management or acquisition of more than 31,000 MW of competitive power generation and 470 miles of transmission infrastructure, for which LS Power and its affiliates have raised over $29 billion in debt and equity financing. LS Power works to identify the need for new power generation and transmission infrastructure and works with our customers, including investor-owned utilities, electric cooperatives, municipal utilities, and regional power pools, to sell competitively priced electricity on a wholesale basis. The power generation facilities developed and controlled by LS Power and its affiliates operate primarily as Exempt Wholesale Generators ("EWGs") pursuant to the rules of the Federal Energy Regulatory Commission. As such, the generation facilities are engaged *exclusively* in the business of owning and/or operating facilities and selling electric energy at wholesale. See 42 U.S.C. 16451-16463 (2012) and 18 C.F.R. 366.1 (2013). Given the limitations placed on EWGs pursuant to FERC regulation, LS Power offers a unique perspective regarding the potential impacts of the Federal Plan on such independent power producers ("IPPs"). Specifically, LS Power believes it is critical that EPA establish a framework in the Federal Plan that recognizes the regulatory limitations on some generators and encourages generators to implement cost effective operational changes to reduce emissions directly from the individual source. In addition, to help minimize potential costs of compliance for these EGUs, LS Power recommends that EPA establish a robust interstate emission reduction credit ("ERC") program. Based on this perspective, LS Power provides the following specific comments for EPA's consideration in developing the Federal Plan:

1. EGU Credit Creation

EPA is considering implementation of a Federal Plan that would place the emission reduction responsibility on the individual EGUs. In a rate based system, EGUs will be responsible for achieving emission rate targets derived from EPA's four building blocks approach. In many instances, an EGU's emission rate reductions cannot be achieved at the source itself, and it is anticipated that EGUs will need to purchase credits pursuant to a carbon credit program that EPA will implement as part of the Federal Plan. As discussed below, LS Power recommends that EPA establish an interstate emission reduction credit program as part of the Federal Plan.

In developing the Federal Plan, EPA should take into consideration that there are many owners of generation, including investor owned utilities, municipal utilities and cooperatives, as well as IPPs. Many generators, such as independent power producers, operate as EWGs and participate solely in the wholesale markets. These generators do not serve load and are outside of the jurisdiction of most state public service commissions. As a result, such generators do not have the direct ability to implement the same types of programs as load serving entities ("LSEs"). Unlike EWGs, LSEs have access to energy system emission reduction opportunities under EPA's Building Blocks 3 and 4.

Conversely, actual emissions reductions at the specific plant or unit are something all generators can pursue while also providing the best economic solution. Since such reductions at the source work to reduce total carbon emissions, such reductions should result in the creation of credits. Specifically, an action by a unit to curtail its operations or even to cease operation should result in the creation of credits. A rate based federal plan, however, does not directly yield such an outcome since a unit's rate of carbon emission does not decline as a result of reduced operations.

Such an outcome fails to properly incentivize generators to undertake operating restrictions or limitations and eliminates a method for credit generation that would be available to many small entities operating solely in wholesale markets. LS Power encourages EPA to draft a Federal Plan that properly incentivizes generators to make operational adjustments that reduce generation by granting credits for such actions. Creating a credit mechanism tied to reductions in EGU operations is not straight forward in a rate based system since simply reducing operating hours will not result in any rate reductions. We suggest that EPA explore creating credits for such activities and should create credits based on assumptions that reduced operations at a covered facility will bring about the re-dispatch of generation to lower carbon emitting generators. EPA should recognize credit generation based on the reduction of carbon emissions realized by such re-dispatch.

2. Robust Credit Market

Since individual EGUs have no control over outside-the-fenceline, energy-system wide emission reduction opportunities, EPA must develop a robust interstate ERC program to connect the EGUs with the broader energy system and provide them with an assured compliance option at a reasonable cost. This is a particular concern to small business IPP owners of EGUs. IPPs participate in the competitive wholesale energy markets along with traditional investor owned utilities ("IOUs"). Requiring EGUs to purchase ERCs will add costs to operations. EGUs that are short ERCs run the risk of financial penalty and/or curtailment. Additionally, if the Federal Plan also includes new units, new entrants looking to develop EGUs will face barriers to entry should such ERCs be scarce. Consequently, companies that acquire ERCs can gain a competitive advantage by increasing costs to other EGUs and precluding the development of new facilities. Small entities are particularly vulnerable to this risk as larger EGUs may be better positioned to buy up or hoard credits in order to gain a competitive advantage. The risk for abuse is heightened in regulated states where EGUs are owned by IOUs. In such circumstances, IOUs are typically regulated by state public service commissions that can approve certain expenditures and pass those costs along to ratepayers. Costs incurred to comply with environmental laws and regulations are typically approved for cost recovery. Consequently, these purchasers of ERCs are indifferent to cost and have every incentive to remove ERCs from the market since the cost of purchasing the ERCs will be directly passed through to ratepayers.

In light of this potential for abuse, LS Power requests that EPA ensure a liquidity of ERCs. To accomplish this, EPA should consider the impacts on liquidity associated with the unfettered right to bank ERCs and from creating ERCs of unlimited duration. We encourage EPA in crafting the rules of an ERC market to protect small generators from the potential for such abuses.

To help ensure the success of the ERC program, LS Power recommends the creation of a national data base for the registration of the emission reduction credits. In addition, LS supports EPA providing flexibility in the Federal Plan to allow businesses to form for the purpose of creating and selling credits based on the full range of energy system opportunities. This approach should help minimize costs/impacts to small businesses by providing more affordable and readily available credits.

3. Mass Based Allocations

To the extent a federal plan incorporates a mass-based plan, a critical component is the allocation of allowances. LS Power supports an initial free allocation of allowances as opposed to an auction system. Additionally, there is considerable concern regarding the basis for determining such allocations. Other mass based plans have based allocations on historical emissions. Utilizing such an approach here would undermine the emission reduction goals of the Clean Power Plan.

As EPA has recognized, a significant number of natural gas combined cycle ("NGCC") generating units are underutilized. EPA's Building Block 2 provides a generic goal of achieving 70% capacity factors at existing NGCC plants. LS Power expressed its support for this objective in comments submitted to the Emission Guidelines proposal. In light of the underutilization of existing NGCC plants, these plants will have relatively lower historical carbon emissions due to their lower capacity factors. Basing an allocation on these lower emissions is inconsistent with EPA's stated goal for these units to increase their operations. Historically underutilized NGCC plants would receive very low allocations and would be forced to purchase greater allowances to cover increased operations.

Consequently, such a program would impose additional costs on the very types of units EPA is looking to operate more. This issue is of particular concern to IPPs since, based on LS Power's experience, many of the facilities owned by those entities have available capacity and would be penalized for lower historical capacity factors. While some have proposed utilizing an averaging period, (such as a three or five year look back or highest of the past five years), such an approach is insufficient to address the prolonged period of underutilization these plants have experienced. To the extent a mass based approach is utilized, LS Power encourages EPA to base allocations on the state specific target for capacity factors of NGCC plants.

Conclusion

LS Power appreciates the opportunity to provide these comments for EPA's consideration as it develops the Federal Plan. We look forward to working with EPA to formulate a workable plan that is equitable for generators of all types and ensures all entities equal access to credit and allowance markets.

Sincerely,

LS Power Development, LLC

By: ______________________
Scott Carver, Sr. VP and Associate General Counsel

Wabash Valley Power
energy smart

May 28, 2015

VIA EMAIL

Ms. Lanelle Wiggins, RFA/SBREFA Team Leader
US Environmental Protection Agency
Office of Policy (1803A)
1200 Pennsylvania Avenue NW
Washington, DC 20460

Re: SBAR Comments for the Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014

Ms. Wiggins,

Thank you for providing us with the opportunity to participate in this SBAR Panel and provide comments on the May 14, 2015 Federal Plan presentation. As an affected small business, Wabash Valley Power Association, Inc. (WVPA) is an electric generation and transmission cooperative that provides wholesale power to its 24 distribution cooperative members, which consist primarily of rural electric membership corporations (REMC), in Indiana, Illinois and Missouri. WVPA has ownership interests in electric generating facilities – our fleet consists of a natural gas-fired combined cycle facility (NGCC), a petcoke/coal-based integrated gasification combined cycle (IGCC) facility, a coal-fired unit, several natural gas-fired peakers, several landfill gas to energy plants among other things. Also through WVPA, our REMC's offer their members energy efficiency and demand-side management programs. As such, WVPA has a significant interest in the Federal Plan & this process and offers the following comments.

Wabash Valley Power's mission is to deliver affordable, reliable electricity and would like to provide meaningful comments as part of this process; however, USEPA's presentation to the SBAR Panel does not give us adequate information and insight into the Federal Plan. Overall, WVPA supports carbon pollution standards and guidelines for existing electric generating units; but USEPA should consider extending this SBAR Panel process and provide additional information on the Federal Plan so that WVPA and other small business stakeholders may provide the meaningful comments needed to assist USEPA with drafting such a Federal Plan.

With that being said, it appears that USEPA may be leaning towards an allowance program – whether it be mass- or rate-based. It is unclear how such a program could be drafted based on the most recent historical emissions from WVPA's fleet. For instance, our NGCC facility ran at no more than 15% utilization over the course of the past several years because it 'wasn't in the money' to be called to run by MISO, congestion issues in the transmission lines or some other reason not related to the units being unavailable. Even if these hurdles were overcome, this facility is limited by its CAAPP (air) Permit. In the support documentation accompanying the proposed 'Clean Power Plan', USEPA assumed that the entire facility (duct burners, steam turbine & combustion turbines) could be dispatched at 70%. In fact, the air permit limits each duct burner with a firing limit of 1,500 hours per year limit – this additional MW capacity is unavailable for more than 80% of the year. Should this facility need to run more often, this would require us to re-open the CAAPP Permit and likely trigger New Source Review. It is expected to pose a large hurdle in order to overcome the relaxing of these limits. In addition, these units are also limited by its NPDES (water) permit. Even though the facility is equipped with a closed cycle cooling tower, the NPDES Permit has thermal effluent limitations that cannot be exceeded. If the effluent temperature exceeds the limit and the facility is forced to stop discharging, the facility could continue to run for several hours. However, the facility may have to discontinue operation if temperatures (discharge and/or upstream river temperature) do not come down. The NPDES permit also prohibits the discharge from the permitted outfall to the Kaskaskia River if the river flow is less than 10 cfs. This is effectively a shutdown requirement. Any permitting revisions to 'relax' these thermal issues when it is generally due to warmer temperatures mixed with dryer weather patterns and our members need to cool their homes would be another very large hurdle to overcome with the anti-backsliding provisions in the Clean Water Act. These water issues are not unique to WVPA's NGCC facility. These errors need to be corrected considered accordingly.

Also, the presentation was not clear about the unit of measure used to calculate rate-based crediting. The proposed Clean Power Plan based the unit of measure in Building Block 1 as lbs/NET MWh - this is of particular concern for us and, we believe, other utilities. Should USEPA decide to use NET MWh as a unit of measure in these or other calculations, it would pose FURTHER complications when a facility needs to also comply with other new regulations. For instance, the recently finalized 316(b) rule regulates the intake of water for cooling purposes – also affecting natural gas plants. As you are familiar, under 316(b), a power plant would need to limit its impact on aquatic biota after several years of study. The result could be to add a new cooling tower or the like which, in turn, would add more parasitic load. This results in higher carbon dioxide emissions from a plant, not because it increased its carbon dioxide emissions output from the stack, but because the NET MWh number is smaller on the denominator side of the equation due to the additional need for power to run this required cooling tower. As more regulations come down the pipeline, it's likely that such parasitic load will increase to accommodate additional pollution controls. USEPA should consider setting this portion of the equation based on gross megawatt-hours instead.

WVPA is a member of the National Rural Electric Cooperative Association (NRECA) and endorses those comments.

Finally and most importantly, WVPA would hope that this Federal Plan will not have a disproportionate effect on electric cooperative members. On average, electric cooperatives serve a membership with lower median household income levels and higher unemployment rates than their investor-owned utility counterparts – a fact that is absolutely true of WVPA's members. Rural areas of our states are much slower to realize an economic recovery, and with that, the income and employment levels are also slower to recover. We urge USEPA to consider the effects of this proposal on those who contribute a much higher portion of their household income to have the basic necessities at home.

Our comments are not unique. WVPA appreciates the opportunity to comment on this proposed rulemaking. Wabash Valley Power urges USEPA to proceed in a manner that allows our rural customer base to continue to enjoy affordable, reliable electricity, especially during this slow economic recovery. We've taken thoughtful, proactive steps to protect the environment and our members – both present and future. We encourage USEPA to take these human considerations into effect.

Sincerely,

S. Dear Schramm-Satayathum
Manager, Environmental Affairs
Wabash Valley Power Association

www.orrutilities.com

JEFF A. BREDIGER
Director of Utilities

P.O. Box 107
207 North Main Street
Orrville, Ohio 44667-0107

jbrediger@orrutilities.com
Phone 330.684.5012
Fax 330.684.5040

May 28, 2015

Ms. Janet McCabe
Acting Assistant Administrator for Air and Radiation
U.S. Environmental protection Agency
Mail Code: 6101A
1200 Pennsylvania Avenue, NW
Washington D.C. 20460

Mr. Alexander Cristofaro
Small Business Advocacy Chair
U.S. Environmental protection Agency
Mail Code: 1803A
1200 Pennsylvania Avenue, NW
Washington D.C. 20460

Re: Comments submitted to the Small Business Advocacy Review Panel (SBARP) regarding USEPA's Proposed Federal Plan for Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.

Dear Administrator McCarthy and Staff:

The City of Orrville (Orrville) appreciates the opportunity to submit the following comments to the SBARP. Please note that as the designated Small Entity Representative (SER), I am also submitting these comments on behalf of American Municipal Power, Inc. (AMP) and the Ohio Municipal Electric Association (OMEA) and their members. In addition, we support comments offered by our national organization, the American Public Power Association (APPA).

Orrville is a city of slightly less than 10,000 citizens in Northeast, Ohio. Orrville has owned and operated a municipal power electric utility for the benefit of Orrville's residents and industrial and commercial customers since 1917. Orrville's generation resources include four coal-fired units at the Orrville Utilities Power Plant as well as participation in natural gas, wind and hydroelectric projects elsewhere. Orrville is committed to expanding and diversifying its generation options while continuing its mission to provide low-cost power to its customers.

Ohio-based AMP is the non-profit wholesale power supplier and services provider for 132 locally regulated municipal electric entities located in Delaware, Kentucky, Indiana, Maryland, Michigan, Ohio, Pennsylvania, Virginia, and West Virginia. AMP's members collectively serve more than 625,000 residential, commercial, and industrial customers and have a system peak of more than 3,400 megawatts (MW). The OMEA represents the state and federal legislative interests of AMP and 80 Ohio municipal electric systems.

Because of AMP's structure as a non-profit wholesale power provider, AMP closely follows regulatory initiatives that have the potential to impact the costs and reliability of our members' energy and capacity supply. To that end, AMP's/OMEA's concerns regarding the design elements of limits on CO2 emissions from existing power plants reflect expected impacts of the upcoming standards on AMP and member units, as well as to other units in the region, from which AMP/OMEA members expect to acquire varying proportions of their power supply through wholesale market purchases. The multi-state nature of AMP's/OMEA's membership and power supply portfolio, plus the various types of electricity markets within which we operate, all point to the need for careful consideration of all options, particularly those that acknowledge that "one size does not fit all" when it comes to carbon standards.

I. The timelines for action are too compressed.

The timelines expressed in the proposed rule are very aggressive, particularly when considering the unique and precedent-setting nature of the proposal. Even if state agencies are able to re-allocate necessary resources away from other environmental and energy programs, it may be impossible to meet U.S. EPA's proposed deadlines. The proposed (CPP) states that interim goals must be achieved on average over the 2030 to 2029 period. But because of the stringency of the goals, many states will need to take actions by 2020 in order to establish the programs needed to comply. In recognition of this fact, U.S. EPA should eliminate the interim deadlines.

U.S. EPA needs to give stronger consideration to the schedules associated with state legislative sessions. State administrative procedures can be lengthy and burdensome, even without the new legislative authority many states will need. The time between the expected finalization of the CPP in August of 2015 and the deadline for states to submit plans in the summer of 2016 is simply not enough time to make any necessary administrative and legislative changes, especially given the incompatibility between U.S. EPA's proposed timeline and some state legislative calendars.

II. 111(d) and State authorities

Because over 90% of public power utilities qualify as small businesses under the Small Business Regulatory Enforcement Fairness Act (SBREFA), there are special considerations affecting rural cooperative or municipal utilities that merit adjustments to the rule proposal.[1]

One of the primary issues we have struggled with is how our assets fit into a regulatory scheme that contemplates regulation by both state utility commissions and state environmental agencies. By way of example, in Ohio, AMP and its members fall outside the purview of the Public Utility Commission of Ohio's (PUCO) regulatory authorities based on Home Rule provisions imbedded in the state constitution. Our member municipal electric systems fall under varying degrees of state regulation across our seven state footprint; however, the majority of our members are not subject to state utility commission oversight.

Using Ohio as an example, entities such as our members that own and/or operate generation assets are subject to Ohio EPA's air quality jurisdiction and regulation, but because of Ohio's Constitutional Home Rule provisions they are not subject to enforceable renewable energy (RE) mandates, energy efficiency (EE) requirements or enforceable state-level resource planning processes.[2] In Ohio, this same treatment extends to the state's rural electric cooperatives. This effectively prohibits the ability of either the PUCO or Ohio EPA to regulate our members' activities as contemplated by much of the CPP proposal.

We are not alone in pointing out that the Best System of Emission reduction (BSER) as envisioned by the Section 111(d) proposal functions primarily as an energy policy rather than a rule under the Clean Air Act (CAA). As a result, in Ohio the PUCO is the most appropriate entity to determine how requirements falling under Building Blocks 2-4, such as re-dispatch, are implemented. Yet the PUCO has no authority under Ohio's Constitution and existing laws to reach entities such as our members.

State Home Rule constitutional and statutory provisions are well established and critical underpinnings to the effectiveness of municipal electric system operations. For instance, the local control and decision

---

1 Pub. L. No. 104-121, 110 Stat. 857 (codified as amended in scattered sections of 5 U.S.C.).

2 Ohio Constitution, Article 18

making authority for AMP member municipal electric systems is one of the key reasons cited for our strong bond ratings – bond ratings that support our efforts to diversify our portfolios. The concept of the Section 111(d) plan reconfiguring the energy sector so that cooperatives and municipal utilities become regulated by a public utility commission is difficult to comprehend, not to mention at complete odds with the core purposes of these entities. AMP's stated mission is to provide affordable and reliable power to members based on principals of self-governance and local control.

Entities such as AMP and its members like Orrville are "self-regulating" as a matter of state law and accordingly, states generally will lack regulatory jurisdiction for Building Blocks 2-4. State environmental regulatory agencies will in most cases only have legal authority for obligations under Building Block 1, which in some cases case would result municipal fossil-fuel fired generating assets bearing the entire burden of achieving the CO2 goal. Indeed, U.S. EPA implicitly suggests that states reference the burdensome results of a state plan based on just Building Block 1 to entice non-jurisdictional entities like Orrville to voluntarily submit to broader jurisdiction.

U.S. EPA's proposed "voluntary" submission by cooperatives and municipal utilities creates tension between long-standing and established legal rights in exchange for purported compliance "flexibility" with the energy policy changes dictated by the Section 111(d) proposal.

Based on the unique challenges faced by small municipal and cooperative non-profit utilities, we believe it is incumbent upon U.S. EPA to evaluate and consider exempting altogether or creating a separate category for these entities that would not impede their ability to continue to provide basic services while at the same time providing for reductions in carbon emissions commensurate with their size and contribution.

III. Small entities rely on limited energy sources

Recognizing the unique circumstances and relatively minimal emissions of small municipal coal generators, AMP/OMEA believes these entities are appropriate for exemption from the Section 111(d) program entirely. There are numerous small public power utilities that have only one generation resource under 100MW, and the implications of the CPP on these communities are significant. These municipal utilities do not have the ability to rely on other units which decreases the availability flexibility and options under the CPP, but also increases the impact of costs to comply, both to the municipal utility and to the small businesses it serves.

For instance, based on USEPA's 2013 facility level GHG data, both AMP members Orrville's and Hamilton's GHG emissions were orders of magnitude lower than emissions from typical investor-owned utilities. This is because they are smaller and are used less than the base load units at investor-owned utilities. Municipal utilities are dispatched based on the demand from the communities they serve and the relative cost of other sources of power. As a result, capital invested in EE improvements and fuel switching at a municipal utility will produce far fewer GHG reductions than the same investment at a larger base load EGU. Therefore, the inclusion of small municipal generators will result in minimal GHG reduction benefits while simultaneously imposing significant, disproportionate and unreasonable costs.

U.S. EPA assumes that efficiency improvements and/or fuel switching is available for small emitters to further reduce emissions, but the expense associated with such activities are cost prohibitive given the age of most municipal units. Additionally, many municipal coal generators have already converted units to natural gas. Overreliance on a single fuel source renders small municipalities and their customers vulnerable to significant market fluctuations in the cost of fuel and electricity. It is essential that these entities maintain diverse power portfolios in order to protect their citizens against such fluctuations.

Again, if not exempting these entities from the Section 111(d) state plans, U.S. EPA should create a separate category limited to small municipal or cooperative generators with a cutoff point tied to sales of less than 219,000 MWh per year to the grid. Entities in the separate category would then qualify for an alternative, utility specific goal in the state plan, rather than the overall state goal.

IV. Precedent-setting nature of the outside-the-fence building blocks

Like many other impacted parties, AMP is struggling with the concept of an outside-the-fence regulatory approach. Significant legal and practical issues would need to be resolved before any state could utilize the portfolio approach envisioned by the third and fourth Building Blocks outlined in the proposal. Most importantly for municipal utilities that qualify as small businesses, U.S. EPA should ensure access to emission reductions outside-the-fence in order to avoid shutting the unit down as the only compliance option, since heat rate improvement options may be limited.

V. New Source Review (NSR)

U.S. EPA assumes that the heat rate of the existing coal fleet can be improved by 6%, with 2% of that coming from equipment upgrades. Yet a physical change or change in the method of operation relating to efficiency improvements at an affected EGU also has the potential to trigger NSR applicability determinations. If NSR is triggered, the facility may decide to opt out of such efficiency improvement projects, which is counter to the intent of the proposed emissions guidelines. Likewise, if the efficiency improvement is required by a state plan, U.S. EPA and the state are basically mandating a change that could trigger NSR. What makes the approach even more troublesome is that after mandating an efficiency improvement that triggers NSR review and a significant capital investment, the rule would then dictate decreased dispatch of the EGU in favor of less carbon intensive generation. Of course, just to add to the irony, decreased dispatch means decreased efficiency.

U.S. EPA must modify the proposal to ensure that NSR does not serve as a regulatory deterrent to effectuating the development of lower-emitting and more efficient power generation. AMP/OMEA proposes that U.S. EPA include an explicit exemption to NSR permitting requirements for projects or activities undertaken by affected entities to comply with Section 111(d). EGUs should be able to increase capacity at efficient units without an NSR penalty, as this action ultimately is consistent with the goals of the rulemaking.

VI. Conclusion

Throughout the Section 111(d) process U.S. EPA has highlighted that the proposal provides states flexibility in their approach to reducing CO2 emissions, and that the proposed guidelines provide options for meeting the state specific goals in a manner that accommodates a diverse range of state approaches. However, we are cognizant of the fact that the flexibility U.S. EPA advocates is limited to choosing the methods of emission reduction and timeframe of plan development and implementation. No flexibility is given in determining the total emission reduction figure.

We advocate for U.S. EPA providing a separate pathway for small public and cooperative utilities to achieve reductions in CO2, but over a longer time period consistent with their technical and financial abilities. This would avoid the retirement of small entity coal-fired generating plants. The retirement of these EGUs while they are still able to provide ongoing economic and reliability value will impose an unreasonable cost on not only the entity, but also its customers.

While by no means exhaustive, these comments provide issues of significant concern to us relative to the impact of the proposed existing unit rules to members who qualify as small businesses under SBREFA. We appreciate the opportunity to provide input to the SBARP; please let us know if you need additional information.

Respectfully Submitted,

Jeff Brediger
Director of Utilities
City of Orrville, OH
330-648-5101

cc: Lanelle Wiggins, FRA/SBREFA Team leader
EPA Office of Policy
William Jefferson Clinton Building
1200 Pennsylvania Avenue, NW
Washington, D.C. 20460

Ms. Claudia Rogers
Acting Chief Counsel for Advocacy
U.S. Small Business Administration
409 3rd Street, SW
Washington, D.C. 20416

The National Rural Electric
Cooperative Association

Comments to

The Environmental Protection
Agency SER Panel

On

Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility
Generating Units Constructed on or before January 8, 2014

Submitted Electronically to:

Lanelle Wiggins RFA/SBREFA
Team Leader U.S. EPA
Office of Policy

May 28, 2015

By

Rae E. Cronmiller
Environmental Counsel
4301 Wilson Boulevard, EU 11-249
Arlington, VA 22203-1860
(703) 907-5791

Introduction

The National Rural Electric Cooperative Association (NRECA) appreciates the opportunity to participate on EPA's Small Business Regulatory Enforcement Fairness Act (SBREFA) Small Entity Representative (SER) panel to address the Clean Air Act (CAA) Section 111(d) NSPS GHG rulemaking on the Federal Plan for electric utility generating units (EGUs) and to submit our comments as part of the panel's deliberations and recommendations.

NRECA is the national service organization for more than 900 not-for-profit rural electric utilities that provide electric service to approximately 42 million consumers or 12% of the Nation's population, in 47 states. All or portions of 2,500 of the nation's 3,128 counties are served by rural electric cooperatives. Collectively, cooperative service areas cover 75 percent of the U.S. landmass.

Electric cooperatives are not-for-profit, consumer-owned private entities incorporated in states in which they reside. Sixty-five rural electric generation and transmission cooperatives (G&Ts) generate and transmit power to 668 of the 838 distribution cooperatives. The G&Ts are owned by the distribution cooperatives they serve. By design, the G&Ts have very high debt/equity ratios and no equity holders aside from the electric consumers they serve. Thus, under the cooperatives electric business model, consumers must pay all generation and operating costs. The distribution cooperatives not served by a G&T receive power directly from other generation sources within the electric utility sector. All but three of the G&Ts, and all of the distribution cooperatives are "small business entities" as defined by SBREFA regulations. Twelve small business entity G&Ts are participating on this SER panel. NRECA's recommendations on the 111(d) federal plan follow.

The panel should have had the opportunity to comment on regulatory options presented to it by EPA. First, we stress to EPA the difficulty in commenting on a proposed 111(d) federal plan for small business entity EGUs under such an unrealistically short deadline with no proposal to study and, therefore, with no opportunity to offer constructive comment on any such proposal. At this point, it is impossible to fathom that EPA has not developed a reasonably complete proposal for a 111(d) federal plan. And yet, the SER panel did not see a single written proposal, or even a portion thereof, authored by EPA that reasonably delineated options it may be considering. This is very troubling and contrary to EPA's own guidelines stipulated for SER panel input to EPA's regulatory process.

Developing a NSPS federal plan for GHGs under Section 111(d) involves complexities heretofore not encountered in the NSPS context, because unlike other EGU emissions regulated under the CAA, the underlying 111(d) proposal attempts to regulate the entire electric grid as well as the habits and electricity usage of every one of the nation's electric consumers. In essence, the SER panel is expected to comment on how to improve the obviously intricate and complex inner workings of a black box federal regulatory plan. There is much at stake here. EPA's own modeling of 111(d) implementation effectively eliminated 20% of all cooperative-owned electric generation. Moreover, it appears that this percentage is an overly conservative estimate. Even for those electric cooperatives that might be fortunate enough to have coal-fired EGUs still "standing" after 111(d) regulatory implementation, they likely face the still-daunting task of meeting 111(d) mandates while keeping electric rates reasonably affordable.

Nonetheless, our suggestions in the comments that follow would almost certainly vastly improve whatever EPA may be thinking regarding specific elements of a federal plan, and thus mitigate the impacts on small business entities.

The Federal Plan must allow for small entity EGUs to operate through their remaining useful lives.

As emphasized at the SER panel meeting, small entities typically have one or just a few generating units that make up the majority of the small entity's generation portfolio, and therefore, the operation of these units is critical to the financial stability and viability of small entities. As opposed to larger systems that are better positioned to compensate for unit closures, premature closure of a small entity's unit before its remaining useful life expires can easily place the small business entity in financial difficulty. For example, if the debt obligation on the unit is outstanding at the time of the unit's forced closure, the small entity must incur a double expense in servicing the remaining debt on the expired unit in addition to paying for substitute power to replace the power no longer available from the expired unit. In some cases, unit remaining useful life is keyed to the technical expiration of the unit as opposed to the mortgage length, which may be shorter than the unit's planned and anticipated life for strategic reasons. Likewise, under these circumstances even where the unit's debt obligation has expired, additional unanticipated cost prior to a unit's planned closure would be incurred as the small entity's long-term financial strategic plan for the system is significantly disrupted with the unplanned closure, and the need for additional unplanned generation must now be budgeted and paid for by the electric consumers.

By EPA's own reckoning, 25% of cooperative small business entity units would be forced to retire under the proposed Section 111(d) proposal. We have listed those units EPA has targeted for closure in Appendix A. While we believe this is a conservative prediction, this percentage is already alarming enough, and more than significant enough to require mitigation through the 111(d) federal planning process.

EPA has the clear authority in the CAA Section 111(d) and its longstanding NSPS implementing regulations to grant variances in cases of economic hardship, or to apply less stringent standards when economic factors make such action significantly more reasonable.[1] EPA could allow small business entity unit variances from the requirements on a case-by-

[1] See 40 CFR § 60.24 (f). Unit factors such as unreasonable cost or other factors can provide justification for less stringent emission standards or less stringent final compliance deadlines. The preamble to § 60.24(f) makes clear that EPA itself stipulates that it has the same regulatory authority as the states in granting there sorts of variances, 40 Fed. Reg. 53340 (November 17, 1975).

case basis for allowing operation throughout a unit's remaining useful life. Alternatively, if EPA is steadfastly determined not to allow deviation from its proposed state budgets, EPA should allow a small entity unit to operate as needed throughout its remaining useful life by recognizing early borrowing of credit during unit operation, banking of credit after unit shutdown, and paying back the credit based on the emissions saved by the unit's closure. This should be the case even if the unit's remaining useful life extends beyond the 2030 compliance period.

The Federal Plan should allow borrowing and banking of credit throughout the compliance period and though the interim goal.

Further, as discussed during the SER panel, the interim goal poses particular challenges for many small entity coal-based units, particularly if the state goal requires unit operation curtailment. As noted by the panel, all units require a minimum operation both for technical and financial reasons. Simply put, a unit needs to generate enough revenue to service debt. Each unit has a minimum required operation to do so that is based on the unit's generated electricity, the sale price and the size of the debt. Also, from a technical standpoint, coal-based units must operate at a minimum to function properly. Thus a unit's operation must meet both of these economic and technical criteria. The proposal's interim goal could negate unit operation for either technical or financial reasons. To overcome this potential barrier to operation and ultimately economic viability, the federal plan should allow small entity unit operation as required to be economically and technically viable by allowing early credit borrowing and later payback as units fulfill their remaining useful life.

The Federal Plan must include a dynamic reliability safety valve.

As discussed at the various Federal Energy Regulatory Commission (FERC) technical conferences recently held to explore the full implications of the proposed 111(d) regulation on the nation's electric grid and recently in joint correspondence sent to EPA by all five FERC commissioners, the 111(d) regulatory program must include provisions to ensure grid reliability is not jeopardized by 111(d) implementation.

NRECA and APPA have jointly proposed concepts for a dynamic reliability safety valve (DRSV) that would serve to maintain electric reliability throughout the 111(d) regulatory program in the event that unavoidable or unforeseen circumstances require generation shifts during the compliance period where such shifts were not included or accounted for in state or federal plans.

Several elements of the NRECA/APPA proposal are noteworthy and should be mentioned here. First, approval of any deviation from a state or federal plan is pursuant to a petition filed with EPA and approved by EPA with FERC input. Second, any final decision on a petition is reviewable in federal court. And third, relief sought in any petition is only that necessary to ensure reliability is maintained without creating noncompliance issues for those entities that must deviate from their plan.

The conceptual elements of a 111(d) Dynamic Reliability Safety Valve are as follows:

1. **Purpose of Dynamic Reliability Safety Valve Petition (DRSV):** A petition's function under the DRSV is to request relief from EPA for affected states, regions, and utility entities, as the case may be, from CO2 emission reduction mandates included in an approved state or multi-state plan (SP) or in a federal plan (FP) to the extent necessary or as required in order to maintain adequate and reliable electric service.

2. **Potential triggering events include:** unforeseen and unavoidable circumstances or systemic changes in the availability and operability of electric energy resources relied on by the petitioner to meet the SP or FP. Triggering events include but are not limited to: large changes in available electric generation or electric transmission capabilities; fuel shortages or costs that impair the ability to acquire fuel, including fuel transportation shortfalls; extreme weather events, natural disasters, and acts of war; or changes in the laws, regulations and rules affecting availability of such resources.

3. **Who may submit a petition:** A petition may be individually or jointly submitted to EPA by the party or parties subject to compliance obligation under the SP or FP, including an affected state or states and/or an affected electric utility entity or utility entities. A petition may be accompanied by a regional RTO/ISO or balancing authority in a joinder, but such a joinder is not required.

4. **Content of petition:** The petition shall include the following information: (1) a description of the circumstances relating to adequate and reliable electric service that petitioners believe make full or timely compliance with a SP or FP's CO_2 emission reduction budget, target or milestone impossible, impracticable, or unreasonable, (2) an accounting of the amount by which CO_2 emissions are likely to exceed the budget, target or milestone in order to ensure adequate and reliable electric service and an estimation of the duration of the anticipated exceedance, (3) a description of actions that have or may be undertaken to remedy or mitigate the exceedance while ensuring adequate and reliable electric service, or an explanation of why no actions are available, (4) if actions are identified, an explanation of which actions the state, region, or entity has implemented or proposes to implement, together with a schedule for implementing the selected actions and an estimation of annual CO_2 emissions deviations from the SP or FP during and following implementation of the selected actions, (5) a schedule for completion of the selected actions, and (6) a request for temporary or permanent adjustment in the state, region, or entity's emission budget, target or milestone as the case may require.

5. **Requested relief and remedial actions:** Petitions can include requests for prospective and/or retrospective relief from a CO_2 emission budget, target or milestone on an annual or sum of year's basis to the extent required and based on the annual CO_2 emissions deviations estimated in the petition; however, EPA has the right of annual review to ascertain that affected states, regions, and entities granted the relief are taking remedial actions as described in the petition to remedy the circumstances necessitating the granted relief. Should such remedial actions become no longer viable, the affected parties have the right to submit a revised petition identifying the factors causing the aforementioned actions to no longer be viable and proposing different remedial actions or, as necessary, further relief from the SP or FP's emissions budget, target or milestone.

6. **Due process and procedural steps:** A petition submitted before relevant emissions compliance or true-up date shall serve to toll that date until EPA's approval or denial of the petition. EPA shall evaluate the petition for completeness within a reasonable time, not to exceed 60 days after submittal. Within this 60 day period EPA shall request any additional information needed to complete the petition. Within 30 days after the initial 60-day period or, if additional information is submitted in response to a request by EPA, within 30 days after such information is submitted, EPA shall propose either to grant the petition, deny the petition, or grant the petition in part and deny the petition in part, and shall cause such proposal to be submitted to the Federal Register for publication. EPA shall take public comment on its proposed

action for a period of 30 days. After considering any comments submitted, EPA shall take final action on its proposal in accordance with 42 U.S.C. § 7607.

7. **EPA consultation with FERC on reliability matters:** EPA agrees that FERC will be the lead Federal agency on matters related to reliability of the bulk electric system, consistent with FERC's authorities under the Federal Power Act (FPA) and using FERC's extensive expertise. Accordingly, EPA shall request consultation and guidance with FERC in matters related to reliability of the bulk electric system as contained in a petition and shall give deference to FERC's response. EPA may not deny a petition in whole or part without requesting such consultation from FERC. As part of its responsibilities under the FPA, FERC as appropriate should address whether the triggering event as described in the petition will affect the bulk electric system in such a way that is detrimental to adequate and reliable electric service. FERC will provide its findings to EPA within 30 days for use in evaluating the petition. EPA may depart from FERC's recommendations relating to reliability of the bulk electric system only if EPA explains its reasons for doing so.

8. **Scope of relief to be granted by EPA:** EPA shall not as a condition of petition approval or partial petition approval require emission offsets and shall not impose noncompliance penalties for any actions or inactions that are the subject of an approved petition or for any actions or inactions that are the subject of a partially approved petition. The SP or FP as the case may be will be amended to the extent required to reflect the relief granted in a full or partially granted petition. Such relief shall include adjustments in the compliance obligations of the affected facilities as the case may require.

9. **Final agency action and judicial review:** EPA's grant or denial of a petition for relief under the DSRV shall be considered a final agency action that is locally or regionally applicable. EPA's failure to act on a petition within the time periods provided shall be considered a denial of the petition and treated as final agency action. Petitions for judicial review of EPA's grant or denial of a petition may be filed in the United States Court of Appeals for the appropriate circuit in accordance with 42 U.S.C. § 7607(b).

The Federal Plan should recognize small entities' unique characteristics, special challenges, and other considerations when considering Building Block 4 - Energy Efficiency (EE) requirements.

EPA's proposed 111(d) regulation sets forth a nationwide energy efficiency goal that presumes each state can readily adopt and maintain a 1.5% annual energy efficiency improvement goal. EPA bases this assumption on three states that have achieved this goal over several decades. In fact, one of those states is now scaling back their program, and most other states haven't achieved even half of the 1.5% goal. NRECA's analysis demonstrates that this goal is not cost-effectively achievable in either all states or at all utilities, particularly small not-for-profit utilities.

Due to their unique consumer demographics,[2] small not-for-profit utilities such as electric cooperatives face a considerable challenge to achieve and maintain the significant energy efficiency (EE) savings under EPA's proposed 111(d) regulation, particularly while trying to balance end-use EE gains for residential and small commercial consumers and optimal distribution system operations. However, small not-for-profit utilities do invest in and implement EE programs that result in energy savings, and to effectively contribute to any state or federal goals, their unique circumstances should be considered. We urge EPA to take a tailored approach in the federal plan when crafting energy efficiency compliance pathways. Where small, not-for-profit utilities and their consumers find ways to achieve end-use energy savings; they should be applied to state goals on a voluntary basis. NRECA also recommends that EPA avoid allowing measurement and verification (M&V) to create a significant barrier to energy efficiency program adoption by ensuring methodologies are as simple as possible to meet the specific state or program need. A Federal plan should:

- Tailor setting EE goals to support optimization of all programs employed by the state's utilities and then establish a state-wide plan that recognizes and accommodates these unique differences and challenges
- Establish inclusive guidelines for small utilities that acknowledge their significant variability in cost-effective energy efficiency opportunities, provide

[2] NRECA members average seven consumers (or customers) per mile and include 93% of the nation's persistent poverty counties

flexibility to select energy efficiency programs that benefit their consumers, and the ability to apply those savings towards the state goals

- Avoid prescribing projects – particularly those that aren't cost-effective and that place additional burdens on those least able to participate in programs

- Encourage eligible projects from historically successful programs, including: manufactured housing renovation or replacement, appliance and lighting rebates, home weatherization, conservation voltage reduction, peak energy load management, electricity pre-payment, electrification of equipment, electric vehicles, etc.

- Establish reasonable M&V such as 'pre-implementation plans' for small utilities to achieve a level of savings agreed to by the state.

- Credit savings claimed through participation in government EE programs including DOE's Better Buildings program, EPA's Energy Star appliance and buildings programs, USDA's Energy Efficiency and Conservation Program, municipal revolving energy efficiency loan funds, low-income weatherization programs, and many more as sufficient for Federal Plan Building Block #4 compliance demonstrations.

Brief Comment on other concepts raised in the SER panel meeting.

- *Allocation of bonus "allowances or credits."* Many of the suggested allocation strategies involve the distribution of allowances or credits to accommodate the special needs of small entities in efforts to ensure their viability. While NRECA understands and appreciates this concern, we think that such allowances or credits should only be in addition to those necessary for overall utility industry compliance with state goals. Small business entity EGU greenhouse gas emissions make up only a small amount of overall utility sector emissions, and thus essentially easing restrictions on select small business entity EGUs on a case-by-case basis based on economic hardship or other relevant factors by distributing extra allowances or credits, should EPA propose such a system, would have an insignificant effect on

EPA emission reduction goals for 111(d).

- *Allowing multi-year compliance averaging.* While the proposed 111(d) appears to suggest 3-year compliance averaging, it is unclear how it would function. For small entities, longer averaging times would give them more flexibility for compliance. We suggest 5-year compliance averaging at a minimum for small entities.
- *An Entity should have the option to choose between a rate or mass-based compliance.* Allowing choice here could significantly decrease a small business entity's cost in addition to potentially avoiding premature closure of generating units.
- *New unit option to be included in a 111(d) compliance plan*. NRECA believes that a small business entity should have the option of including new units in its compliance plan. This would be especially helpful where the system has high growth, the need to add base load generation, and the best opportunities to comply rest with operating under a rate-based compliance plan.
- *Multi-year averaging to determine unit baseline.* Multi-year averaging for determining unit baselines would be especially helpful for a small entity that has just one or several units. A unit off-line for an exceptionally long time would be especially penalized if its baseline is largely affected by that long outage time. Allowing multi-year averaging based on the average of the three highest of a consecutive 5-year period would be more representative of a unit's normal operation.
- *Minimizing compliance reporting obligations for units under 100 MW*. The vast majority of greenhouse gas emissions from the utility sector originate from units larger than 100 MWs. Simplifying reporting for these smaller units would assist in reducing the compliance costs of small business EGUs with no recognizable impact on the success of the overall program.
- *EPA's heat rate improvement assumptions for units 125MWs or smaller should reflect technical limitations and financial realities.* Smaller units are less technically and financially capable of achieving the heat rate improvements

associated with Building Block #1 of the proposed 111(d) regulations.[3] The attached study in Appendix B examined the technical and operational characteristics of coal-fired EGUs under 200 MW capacities, and the opportunities for improving their heat rates. The following observations are obvious conclusions from the study:

- Smaller units have far lower average capacity factors than the average capacity factors for the electric utility fleet as a whole. This fact contributes to smaller units having a notably higher average CO2 rate on a lbs. per MWh basis.
- These higher CO2 rates are observed across all units of varying ages and types of coal utilized as a primary fuel.
- Three heat rate improvements selected for evaluation represented a cost range from higher $/MW to lower $/MW, with the improvements associated with the larger units being more cost-effective as compared to the smaller units.
- The lower capacity factors associated with small unit operations coupled with their higher costs of heat rate improvements on a $/MW capacity basis would result in significantly extended payback periods.
- Thus, costs associated with smaller unit heat rate improvements as compared to those of larger ones could cause, on a comparative basis, many of these smaller units to shut down prematurely, in turn causing these smaller unit assets to become stranded.

Accordingly, the Federal Plan should recognize that smaller units are far less capable of achieving heat rate improvements by creating a small unit heat rate subcategory accompanied by lessor heat rate requirements.

[3] NRECA's comments submitted on the Section 111(d) proposal included significant documentation clearly demonstrating the EPA's 6% heat rate improvement assumed for the entire coal-fired EGU fleet is not achievable.

Appendix A

EPA Modelled Small Business Cooperative Coal Unit Retirements under its proposed 111(d) Regulation

EPA Modelled Small Business Cooperative Coal Unit Retirements in 2025 State option (The only run available)			
Cooperative	**Plant Name**	**MW Owned**	
Arizona Electric Power Cooperative	**Apache Station 2**	**175**	
Arizona Electric Power Cooperative	**Apache Station 3**	**175**	
Western Farmers Electric Cooperative	**Hugo 1**	**440**	
Arkansas Electric Cooperative	**Independence 1**	**292.6**	
Arkansas Electric Cooperative	**Independence 2**	**354.6**	
Dairyland Power Cooperative	**John P. Madgett 1**	**372**	
Northeast Texas Electric Cooperative	**Pirkey 1**	**84.7**	
Oglethorpe Power Corporation	**Scherer 1**	**502.2**	
Oglethorpe Power Corporation	**Scherer 2**	**505.8**	
Seminole Electric Cooperative	**Seminole 1**	**647**	
Seminole Electric Cooperative	**Seminole 2**	**663**	
Arkansas Electric Cooperative	**White Bluff 1**	**285.3**	
Arkansas Electric Cooperative	**White Bluff 2**	**295.4**	
Subtotal MW shutdown by EPA model			**4792 MW**

EPA Modeled Small Business Cooperative Coal Unit projected yearly operations too low to be economically viable			
Cooperative	**Plant Name**	**MW Owned**	
Old Dominion Electric Cooperative	**Clover 1**	**215**	
Old Dominion Electric Cooperative	**Clover 2**	**215**	
East Texas Electric Cooperative	**Plum Point**	**50**	
Subtotal MW shutdown due to low capacity factor modeled by EPA but not shut down by EPA			**480 MW**
25% Total MW shutdown under 111(d)			**5272 MW**

Appendix B

HEAT RATE-IMPROVING OPTIONS FOR SMALL, LOW CAPACITY FACTOR GENERATING UNITS: COMPARISON OF CAPITAL, CO2 AVOIDED, AND PAYBACK

Prepared for the

American Public Power Association

And the

National Rural Electric Cooperative

Prepared by

J. Edward Cichanowicz
Saratoga, CA

And

Michael C, Hein
Whitefish, MT

May 27, 2015

Table of Contents

LIST OF FIGURES

LIST OF TABLES

SECTION 1

INTRODUCTION AND SUMMARY

Electric generating units (EGU) of "small" output capacity will encounter barriers to meeting the carbon dioxide (CO2) reduction targets used as the basis of Building Block 1 of the proposed Clean Power Plan. Small generating units, typically considered those of less than 200 MW capacity, cannot economically derive the same benefits in heat rate and CO2 reduction as the larger units that comprise the bulk of the U.S. coal-fired fleet.

Many small units are owned by public power utilities or rural cooperatives and qualify as small entities, as defined by the Regulatory Flexibility Act (RFA) and amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA). Small entities can face limits in raising capital due to the control procedures required for expending public funds.

Municipal utilities raise capital for many of their environmental projects by issuing bonds, which are rated by three major agencies: Moody's, Standards & Poor and Fitch. A bond rating does not constitute a recommendation to invest in a bond and does not take into consideration the risk preference of the investor. While many factors go into the investment decision-making process, the bond rating is often the single most important factor affecting the interest cost on bonds. Moody's has developed a municipal utility scorecard[4] that outlines the rating factors taken into consideration by the agency; these include the system characteristics, financial strength, and various management and legal provisions.

These rating factors are particularly important for small entities as they can dictate decisions about replacing, repairing or modifying aging equipment, all while delivering adequate service with existing resources. Regulatory compliance and capital planning are also factors that rating agencies consider; specifically how well a utility complies with relevant regulations and their plans for capital expenditure to comply with future mandates. Small public power utilities and rural cooperatives are less likely to have generation redundancies, which allow a system to shut down some of its operation in an emergency or to make repairs without interrupting service. Any capital needed is likely to be more costly relative to the limited annual budget of small entities, while evaluating and deploying heat rate improvements will be hampered by limited engineering staff.

This paper explores the barriers that public power or cooperative owners of small units could encounter in deploying heat rate improvements in an attempt to meet the proposed Building Block 1 CO2 reduction goals. The results of this analysis quantify the capital requirement and the "payback" time to recoup the investment for heat rate improvements. Several examples of heat rate-improving options are selected to evaluate the benefit of avoided CO2 emissions in addition to capital required and the payback time. For this analysis, an investment of $750K is

[4] Dan Seymour and Brady Olsen, *US Municipal Utility Revenue Debt,* Moody's, July 30, 2014

selected as an arbitrary threshold defining "higher" or "lower" cost investments. Thus, options considered in this analysis reflect investments of both "lower" cost – those requiring less than $750K – and of "higher" cost, requiring greater than $750K.

The capital requirement, CO2 avoided, and the payback for several heat rate-improving options is calculated for two reference units, reflecting "small" and "conventional" generating capacity. A reference unit of 100 MW capacity is selected to reflect small units, representing the 25-200 MW range. A reference unit of 500 MW capacity is selected to represent "conventional" units. The capital cost for and the benefits of various heat rate options were obtained from analysis conducted for the Utility Air Regulatory Group (UARG)5 and from the 2014 National Coal Council report to the Department of Energy Secretary.6 The reduction in operating cost and the payback time is determined using heat rate benefits and capacity factors appropriate for each unit; the latter 45% and 75% for the 100 MW and 500 MW units, respectively. The delivered fuel price is the same ($2.25/MBtu) for both units.

The results show owners of small generating units will incur a payback period for heat rate-improving options that significantly exceeds that for owners of conventional (e.g., 500 MW) units. Most notably, the payback period for a steam turbine upgrade to a 500 MW unit is shown to be 3-4 years, based on a 200 Btu/kWh reduction in heat rate. In contrast, owners of small generating units – even if assumed to extract a greater heat rate benefit of 250 Btu/kWh – incur an almost 12-year payback period. This extended payback time, given present environmental mandates and the wholesale power market, presents significant risk to owners that a unit will remain a viable generating option. Further, the absolute value of capital required – likely exceeding several million dollars for an installed system – could be a challenge to acquire for small public power entities.

Section 2 describes the approach used in this analysis, and Section 3 the key operating characteristics of small generating units that dictate results. Section 4 summarizes the heat rate-improving options considered in this analysis, and Section 5 presents the results. Conclusions are offered in Section 6.

[5] *Evaluation of Heat Rate Improving Techniques for Coal-Fired Utility Boilers as a Response to Section 111(d) Mandates*, Prepared for UARG by J.E. Cichanowicz and M.C. Hein, October 13, 2014. Hereafter UARG 2014 Heat Rate Report.

[6] National Coal Council 2014 Report to the Secretary of Energy, *Reliable and Resilient: The Value of Our Existing Coal Fleet*, May 2014. Hereafter National Coal Council 2014 Report.

SECTION 2

APPROACH

This analysis employs three elements: (a) quantifying the capacity factor and CO2 emission rate (lbs MWh, net basis) for small generating units; (b) selecting several "reference" units and heat rate-improving options that could be deployed to small and conventional units, and (c) quantifying the results in terms of capital required, CO2 avoided, and the payback period.

First, quantifying the capacity factor and CO2 emission rate of small units that are owned by public power and rural cooperative entities is necessary to distinguish between the operation of small and conventional generating units. This paper focuses on owners that qualify as small businesses, although data from small units owned by a variety of entities is used to strengthen the analysis. Small unit data is compared to analogous data describing the operation of conventional, larger units.

Second, examples of heat rate improvements potentially available to use in an attempt to meet Building Block 1 goals of the Clean Power Plan are selected, based on 2014 reports issued by UARG and the National Coal Council. Heat rate-improving options qualifying as "lower" cost (e.g., less than $750K capital) and "higher" cost (greater than $750K capital) are both considered. The $750K threshold represents an arbitrary but rationale means to delineate heat rate-improving options, which range in cost from several hundred thousand dollars to $7M, depending on unit output.

Third, we define two reference units as examples to quantify the results for a limited number of heat rate-improving options. As noted, capital investment, avoided CO2 emission rate, and "payback" period to recover that investment are determined.

Details and results are presented in subsequent sections.

SECTION 3

OPERATING CHARACTERISTICS OF SMALL ELECTRIC GENERATING UNITS

Section 3 describes the operating characteristics of small generating units that determine the benefit and cost recovery for heat rate reduction options. This discussion is preceded by a description of the generating units selected for analysis.

Reference Units

Reference units are drawn mostly from APPA and NRECA portfolios, focusing on small units operated by owners considered by the Environmental Protection Agency (EPA) to be small business entities.

Table 3-1 summarizes the units used to establish trends in capacity factor and CO2 emission rate based on the last 7 years of operation. Not all generating units in Table 3-1 are owned by entities designated as small businesses (e.g., Tri-State G&T) but these are included to broaden the database.

Seventeen of the units in Table 3-1 are owned by members of NRECA while five are owned by members of APPA.

Small EGU Capacity Factor, CO2 Emission Rate

The capacity factor and heat rate for the small generating units in Table 3-1 are presented in Figures 3-1 and 3-2.

Figure 3-1 describes the average capacity factor, distinguishing between NRECA and APPA owners, based on generation data submitted to the Energy Information Agency (EIA). The data presented Figure 3-1 show an almost year-by-year decrease (with the exception of 2010) in capacity factor from 2007 through 2013. There is little difference in the capacity factor of NRECA and APPA–member units over this time period; capacity factor in four of the seven years is almost identical. Notably, in 2013 the small unit capacity factor is approximately 15 percentage points less than the average generating unit in the national coal-fired inventory.

Figure 3-2 shows the CO2 emission rate (lbs/MWh, net basis) increases over the same period of 2007 through 2013. It is well known that operating at lower load compromises heat rate and elevates the CO2 emission rate. Two examples showing the increase in gross plant heat rate at lower load are presented in Appendix A, representing APPA and NRECA owners. The trend in higher CO2 emission rates is likely influenced by, among other factors, the decrease in capacity factor since 2007.

Table 3-1. Small Units Owned by APPA/NRECA Members

State	Owner/Operator	Station/Units	Capacity (MW, net)
MI	City of Grand Haven (MI)	JB Sims Unit 3	65
OH	City of Orrville (OH)	Orrville	63
CO	City of Colorado Springs (CO)	Drake Unit 6	75
MI	City of Lansing (MI)	Eckert Units 4-6	80
AL	Power South (Alabama Electric Coop)	CR Lowman Unit 1	80
Various	Tri-State G & T	Nucla Unit 4	64
IA	City of Corn Belt (IA)	Earl F Wisdom Unit 1	38
IA	Central Iowa Power Coop	FE Fair Unit 2	41
KY	Big Rivers Cooperative	Reid Unit 1	65
	E. Kentucky Power Coop	Dale Units 1/2/3/4	27/27/81/81
		JS Cooper Unit 1	114
MO	Central Electric Power Coop	Chamois Unit 2	44
WI	Dairyland Power Coop	Alma Units 4/5	55, 82
IN	Hoosier Electric Coop	Ratts Units 1/2	117/117
IL	S. Ill Power Cooperative	Marion Unit 4	173
		New Marion	99

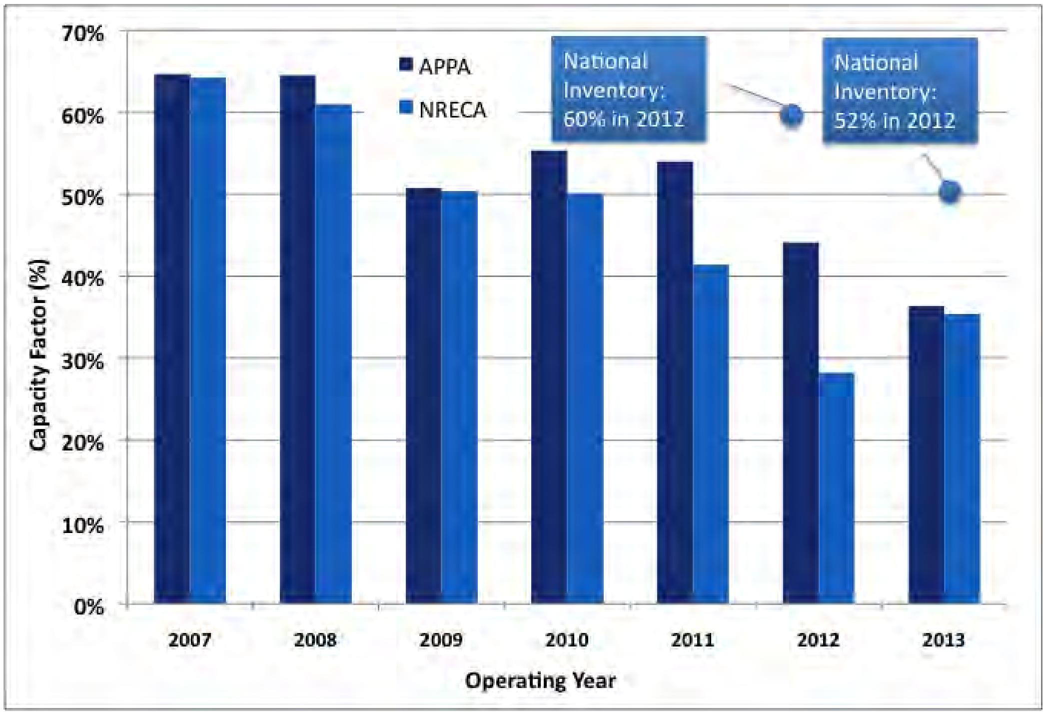


Figure 3-1. Capacity Factor for Small APPA/NRECA EGUs, 2007- 2013

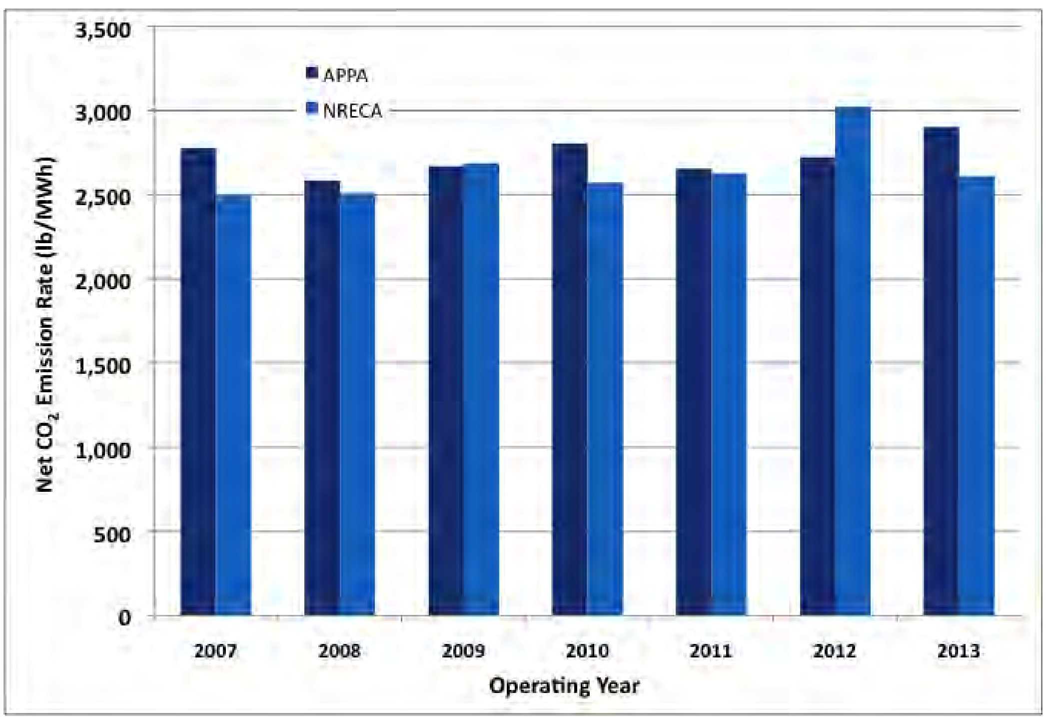


Figure 3-2. CO2 Emission Rate (Net) for Small APPA/NRECA EGUs, 2007- 2013

Comparison to Conventional Inventory

The uniqueness of small generating units compared to conventional, larger coal-fired units is demonstrated by comparing the capacity factor and CO2 emissions from these groups, as revealed in Figures 3-3 to 3-6.

Figure 3-3 shows CO2 emission rates from small units exceed those of conventional, larger units. Units of higher generating capacity can deploy heat rate-improving concepts that may not be economically feasible or even applicable to small units. Figure 3-4 shows the higher CO2 emission rate of small units is not solely due to unit age. Higher CO2 emissions are observed not only for units with greatest longevity – those in service for at least 40 years – but also for units with service of 20-40 years. Even a relatively "new" unit – in service for less than 10 years – will emit more CO2 than newer units in the national inventory, due to either a low capacity factor or constrained design options.

Figure 3-5 provides further insight to the role of capacity factor. This depiction presents data for three of the four quartiles of capacity factor data describing both small and conventional units. The results show higher CO2 emissions are generated from small generating units. Figure 3-5 demonstrates capacity factor alone is not responsible for the higher CO2 emission rate.

Finally, regardless of coal source – bituminous, subbituminous, or a blend of these – higher CO2 emissions are incurred with small generating units (Figure 3-6).

Small Unit Operating Characteristics:

The observations based on data presented in Section 3 are summarized as follows:

- The capacity factor of small EGUs has almost continually decreased each year since 2003. For the year 2013, capacity factor is 15 percentage points less than the capacity factor of an average unit in the national coal-fired fleet.

- Over the same period of time, the CO2 emission rate (lbs/MWh, net basis) has increased, and exceeds by 25% the CO2 emission rate of the average unit in the national coal-fired fleet.

- The higher observed CO2 emission rate of small units compared to the national fleet is observed for units of all ages, ranging from those with less than 10 years to those with more than 40 years of service, and is independent of coal rank.

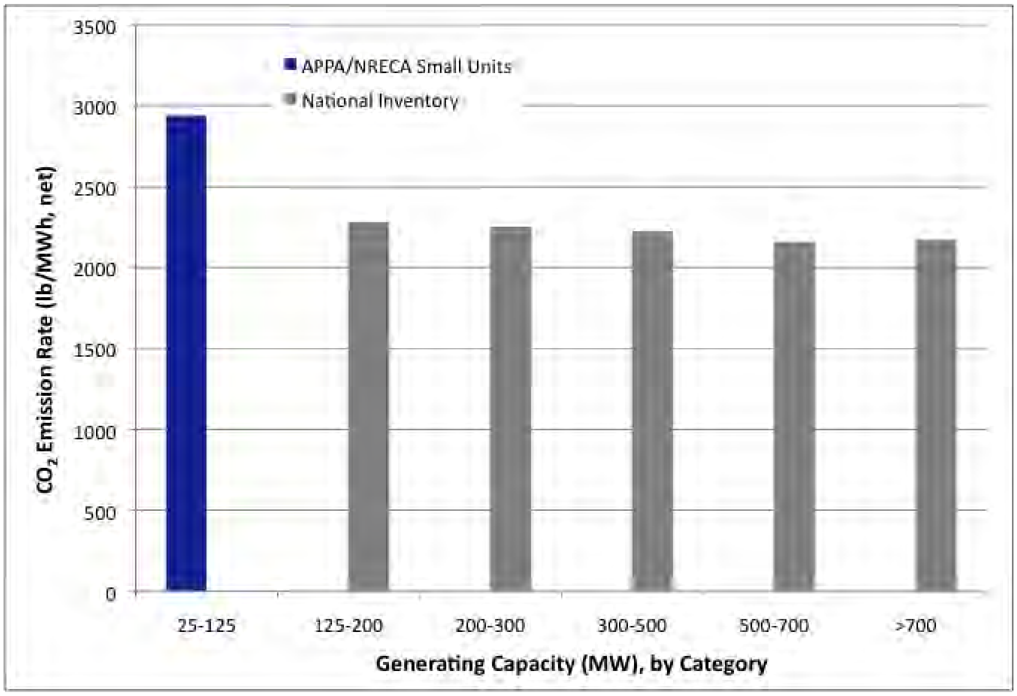


Figure 3-3. CO2 Emission Rates by Categories of Generating Capacity (MW): Small APPA/NRECA EGUs, 2007 - 2013

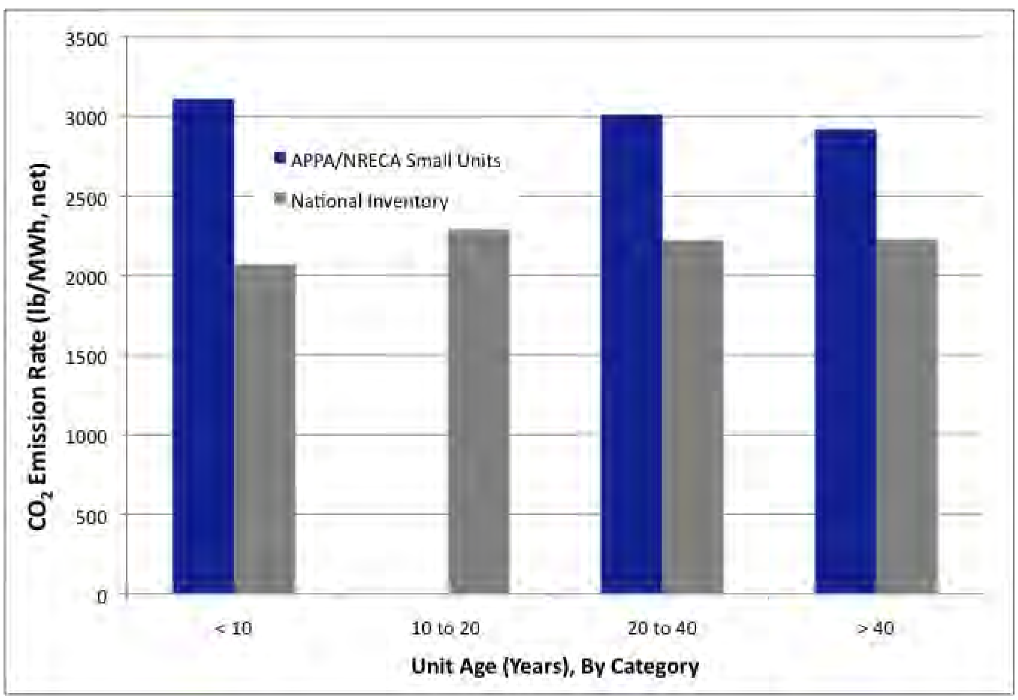


Figure 3-4. CO2 Emission Rates by Category of Unit Age (Years): Small APPA/NRECA EGUs, 2007 - 2013

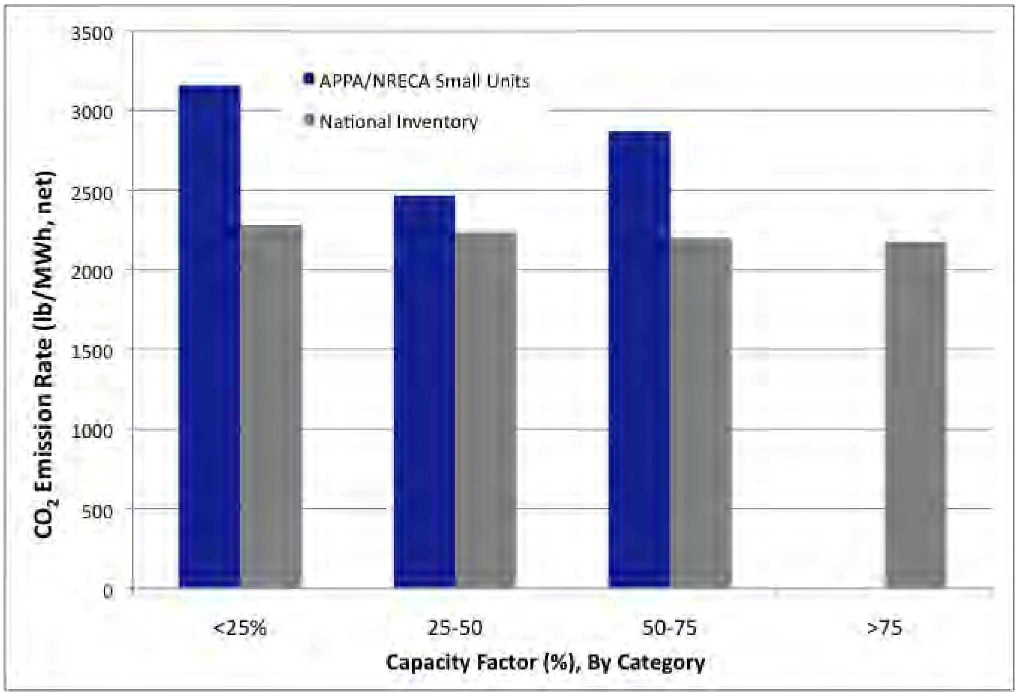


Figure 3-5. CO2 Emission Rates for Small EGUs vs. National Inventory, By Quartiles of Capacity Factor

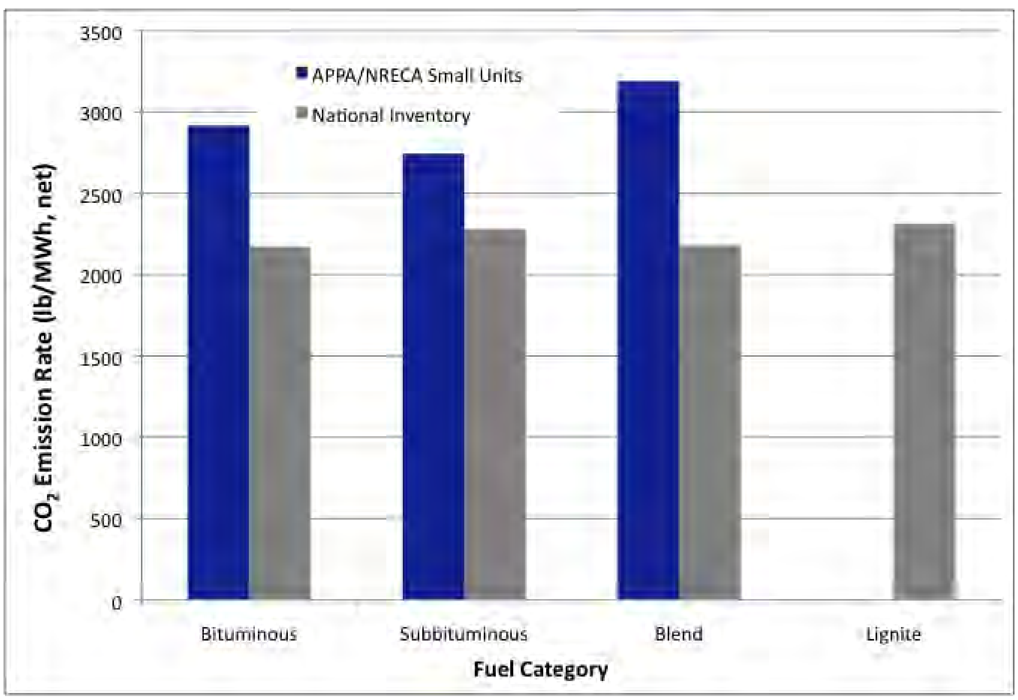


Figure 3-6. CO2 Emission Rates for Small EGUs vs. National Inventory, By Coal Rank

SECTION 4

EVALUATION OF HEAT RATE-IMPROVING OPTIONS

Section 4 describes example heat rate-improving options for small generating units, and the basis for calculating how these options affect unit operation.

Heat Rate Improving Options

The options for improving coal-fired plant heat rate have been summarized in two recent reports – one prepared for the UARG for submission to the EPA as part of comments for Section 111 (d) rulemaking,7 and a second report prepared by the National Coal Council in 2014 recommending research and development actions to the Secretary of Energy.8 A detailed treatment of heat rate-improving options is beyond the scope of this paper; further discussion is referenced to these reports. This section summarizes examples of heat rate-improving options that are available and selects several for evaluation for a reference small and conventional EGU.

Table 4-1 summarizes heat rate-improving actions derived from the UARG and National Coal Council reports. The options are delineated according to the threshold of $750K as defining "higher" and "lower" cost.

The higher cost options in Table 4-1 could require capital for a 500 MW unit from $1 M (boiler surface changes) to $6 M (steam turbine upgrade), providing heat rate savings from 50 to 225 Btu/kWh. The lower cost options all require capital less than $750,000 and could deliver benefits of 20 to 100 Btu/kWh.

Three of the heat rate-improving options in Table 4-1 are selected to evaluate their impact on the two "reference" unit defined. These options are evaluated in terms of (a) capital requirement, in terms of both total expenditure (i.e., $M of dollars) and normalized to generating output ($/kW), and (b) investment payoff in heat rate and CO_2 reduction.

[7] UARG 2014 Heat Rate Report.

[8] National Coal Council 2014 Report.

Table 4-1. Heat Rate Improving Options

Higher Capital Cost Options	Description
Higher Cost	
Steam turbine upgrade	Improve steam path with changes to either or several of the high-pressure, intermediate-pressure, or low-pressure expansion sections. Requires replacement of steam turbine blades and components.
Condenser replacement	Improve heat rejection to the cooling media – be it once-through cooling or to a cooling tower – by rebuilding or replacing the condenser. Typically condensers are located near the cooling source, and are difficult to access in a typical plant layout. Labor costs can be significant.
Addition to boiler surface area	In concept, the heat removing surfaces in a boiler can be augmented; the original design specifications may not be valid in the present environment or with the present fuel. Labor costs could be significant.
Cooling tower upgrade	The media within a cooling tower that promotes heat rejection – the so-called "pack" material – can be exchanged and in some tower designs improve the heat rejection.
Lower Cost	
Process controls	Improved process controls, most notably neural network software, continually seek the "optimal" plant actions. Requires an existing digital control system.
Improved boiler cleaning	The removal of deposits from boiler heat transfer surfaces by either more aggressive sootblowing or water cannons elevate boiler performance and increases boiler thermal efficiency.
Variables Frequency Drives	Minimizes auxiliary power consumption of ancillary equipment.

One higher cost and two lower cost heat rate-improving options are selected for analysis. The higher cost option selected is improving the steam path with a steam turbine upgrade. This option is broadly applied to conventional, large generating units and benefits from significant technical advances in the last decade.

The lower cost options are improved boiler cleaning and advanced process controls. Improved, on-line cleaning of boiler heat transfer surfaces is achieved by use of aggressive or intelligent automated cleaning devices, such as "smart" sootblowers or water cannons. Advanced process controls typically employ neural networks or other advanced software that continually seek the best combination of boiler operating variables to achieve the lowest net plant heat rate. Both of these options should require less than $750K for either a large or small generating unit. Neither option requires extensive hardware, assuming the unit is equipped with a digital control system; consequently the economies of scale are negligible (e.g. the cost is similar for either a small or large generating unit).

Both options impose a small fixed operating cost that is considered in the payback analysis.

Reference Generating Unit Evaluation
Two reference generating units are selected to quantify the benefit of the heat rate-improving options and define the barriers to implementation. The benefit is the reduction in operating cost and the associated avoided CO2 emissions, the latter expressed in terms of lbs/MWh (net) basis. The barrier to implementation is cost in terms of both capital required (i.e., $M) and per output of power ($/kW).

Table 4-2 summarizes the capital cost and payoff in terms of heat rate improvement that is assumed for the three heat rate-improving options, as applied to the two reference units. The capital costs are derived from the UARG and National Coal Council reports, both of which document capital requirement for units of nominally 500 MW.

Table 4-2. Capital Required and Payoff of Heat Rate Improving Options

Option	Conventional (500 MW) EGU	Small (100 MW) Unit
Steam Turbine Upgrade		
- Capital ($M)	5	2.2
- Heat Rate Reduction (Btu/kWh)	200	250
Advanced Controls		
- Capital ($M)	0.6	0.4
- Heat Rate Reduction (Btu/kWh)	50	75
Advanced Boiler Cleaning		
- Capital ($M)	0.5	0.25
- Heat Rate Reduction (Btu/kWh)	60	80

Capital costs for applying heat rate-improving options to the 100 MW units are not explicitly reported in the literature; consequently, these costs are derived by scaling costs from the 500 MW to the 100 MW capacity. These estimates are derived using a conventional power-law scaling relationship as described in EPRI's Technical Assessment Guide.9 It should be noted that scaling capital cost over a factor-of-five range is uncertain; consequently costs cited for the 100 MW unit should be considered approximate.

Table 4-3 summaries the assumptions required to determine the payback of each heat rate investment. Specifically, the conventional 500 MW unit is assumed to operate at 75% capacity factor, approximating their historical average. The 100 MW unit is assumed to operate at 45% capacity factor. The baseline heat rates are shown, as is the delivered fuel price – the latter selected based on EIA's projected delivered fuel price for 2015.

The capital cost normalized to output, CO2 avoided, and payback period are quantified and presented in Section 5.

Table 4-3. Characteristics of Reference EGUs

Unit Feature	"Small" Generating Unit	"Large" Generating Unit
Capacity (MW)	100	500
Capacity Factor (%)	45	75
Baseline Heat Rate, Net (Btu/kWh)	11,000	9,500
Delivered Coal Price ($/MBtu)	2.25	2.25

[9] TAG Technical Assessment Guide, Electricity Supply – 1993, EPRI TR-102275-V1R7, Volume 1: Rev. 7, June 1993. See Section 8.3.7. "Capital Cost Adjustment – Size and Scale-Up, page 8-11.

SECTION 5

RESULTS OF THE ANALYSIS

The results of this analysis clarify the challenges faced by owners of small units in deploying heat rate-improving options. This is demonstrated by considering the payback period over which capital is returned, which in addition to capital required is a key financial metric.

In the context of this analysis, the "payback" period is the number of years over which lower operating cost due to fuel savings returns the capital investment. The payback period is determined without considering the cost of financing the capital equipment, or the levelization of operating cost over future years. A strict determination of "payback" period would entail accounting for these cost-of-money factors; these are ignored in this approximate analysis.

Normalized Capital Per Payback Period
Figure 5-1 presents the payback period anticipated for investments associated with the three heat rate-improving options for the two reference units. Figure 5-1 shows the capital investment – in this depiction cast in terms of cost per output capacity ($/kW) – for the three options, presented versus the payback period. Figure 5-1 shows the larger generating capacity and higher capacity factor of the 500 MW unit minimizes the payback period – about 4 years for the highest cost option (steam turbine upgrade).

In contrast, the 100 MW unit – although requiring less capital on an absolute basis (i.e., $M of dollars) – is penalized as capital required per generator output is very high. For the steam turbine upgrade, the payback period is almost 12 years - exceeding the payback for the 500 MW unit by a factor of 3. The lower cost options of advanced process controls and deep boiler cleaning feature significantly shorter payback periods – 1-2 years for the 500 MW unit. For the 100 MW unit the extended payback period is 6-7 years.

CO2 Reduction vs. Payback Period
Figure 5-2 presents the CO2 reduction anticipated versus the payback period.

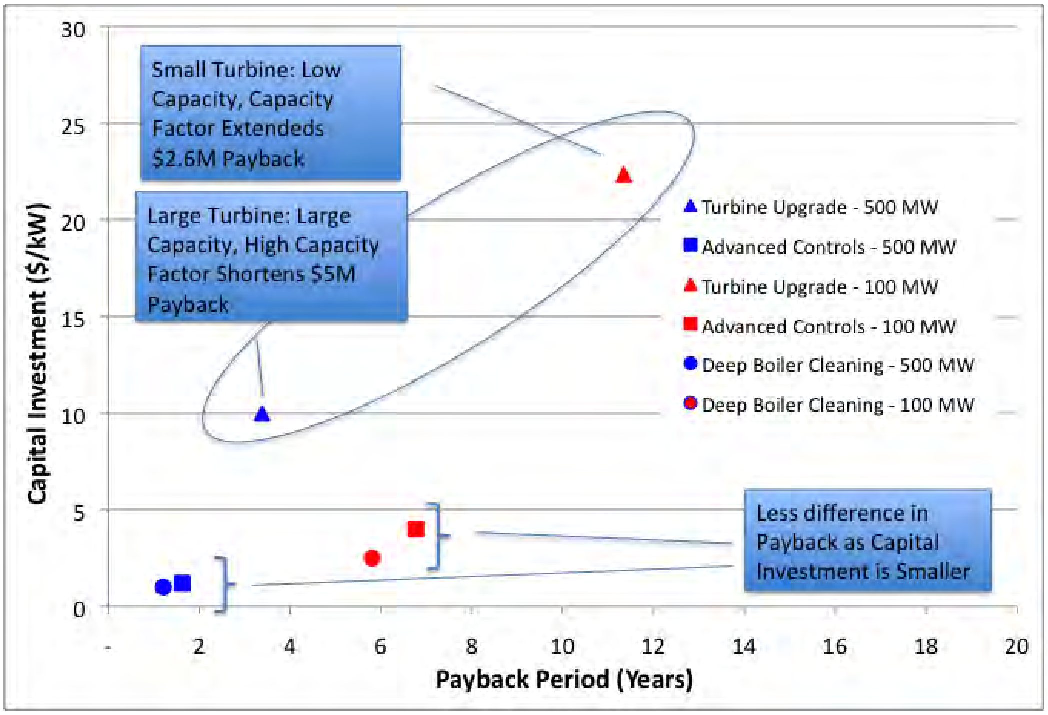


Figure 5-1.

Normalized Capital Investment vs. Payback Period

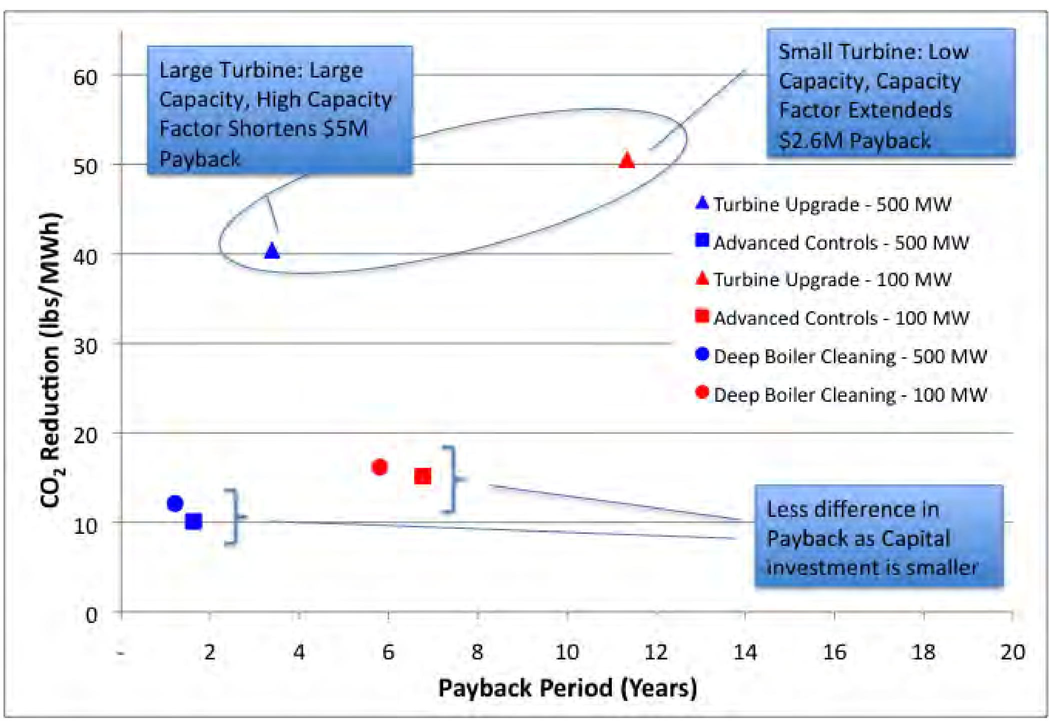


Figure 5-2. CO2 Reduction vs. Calculated Payback Period

Figure 5-2 shows that a CO2 emission rate of 10 and 50 lbs/MWh net can be avoided, depending on the heat rate improving option and the reference unit. The highest value of

CO_2 avoided – up to 50 lbs/MWh for a steam turbine upgrade for the 100 MW unit – requires almost a 12-year payback. The smallest values of CO_2 avoided (10-12 lbs/MWh) require less than 2 years payback.

Results: Key Observations
The results show owners of small generating units, in executing the first steps in an attempt to address the proposed Clean Power Plan, will incur:

- Capital cost ranging from $500-700K and up to more than $2M, depending on the option
- Normalized capital cost from $3/kW to approaching $25/kW, depending on the heat rate–improving option
- Reductions in CO_2 emissions from 10-50 lbs/MWh net, as calculated based on generating capacity
- An extended "payback" period over which the capital investment is returned, due to lower fuel cost, requiring almost 12 years depending on the heat rate-improving option and the reference unit.

These consequences are not the complete impact of meeting the Clean Power Plan, but simply the first steps to attempt to meet the proposed assumptions used as the basis for Building Block 1.

SECTION 6

CONCLUSIONS

Owners and operators of generating units that are either public power utilities or cooperatives can encounter barriers to raising capital, compared to investor-owners of larger units. As a result, public power and cooperative owners are limited in deploying the full suite of heat rate-reducing options. For many such owners higher capital cost options are excluded as they cannot be readily financed.

Small generating units – typically recognized as those with less than 200 MW but in this analysis focusing on units ranging from 44 to 177 MW – are evaluated. Most notable is the extended payback periods for heat rate investments to take the first steps to meet the proposed CO2 emissions reductions assumed for the Clean Power Plan's Building Block 1. The limited generating capacity and lower capacity factor typical of small units are key determinates of the payback period. These conditions create the possibility of small unit owners inheriting generating assets that become "stranded", should these units be forced to shut down prematurely. Payback periods for the higher capital cost options can exceed 10 years, which can compromise the competitiveness of the unit given present market conditions.

The CO2 emission rate typical of small units – as measured in lbs/MWh (net) – is higher than the CO2 emission rate of conventional units. There are numerous reasons for the higher CO2 emission rate – the design of the boiler and steam turbine; lower capacity factor, and frequency of startup/shutdown events.

As a consequence of these barriers, public power and cooperative entities will be restricted to deploying mostly lower capital cost options, limiting CO2 reductions.

Numerous observers and owners of typical coal-fired generators have stated EPA's 6% heat rate improvement assumptions is not technically feasible[10]; the limit to deploying heat rate-improving options to be encountered by public power and cooperative owners of small units further assures this goal as unrealistic.

[10] UARG 2014 Heat Rate Report.

APPENDIX A

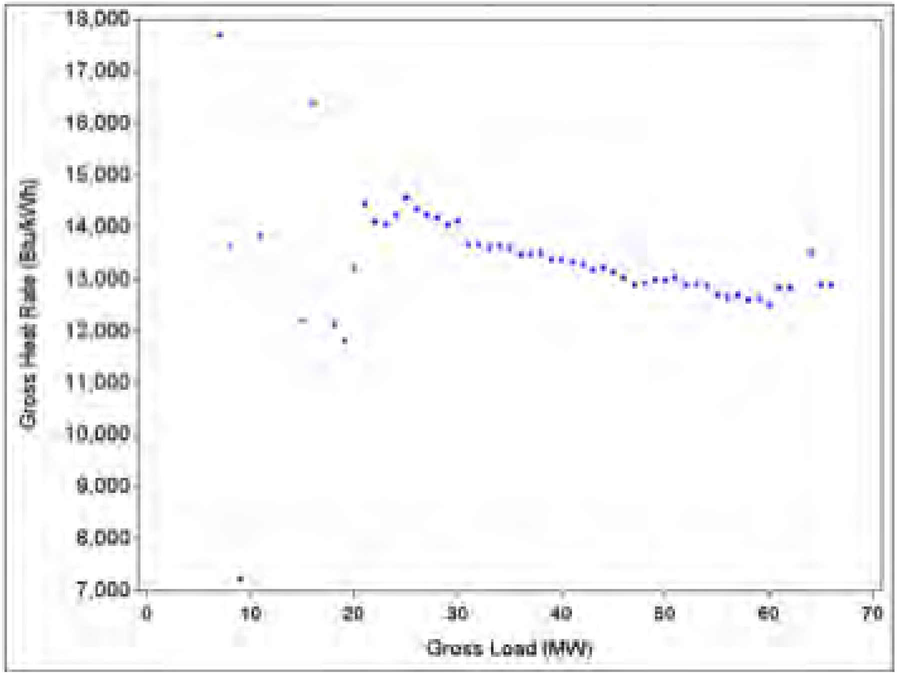


Figure A-1. Gross Plant Heat Rate vs. Load: CR Lowman Unit 1

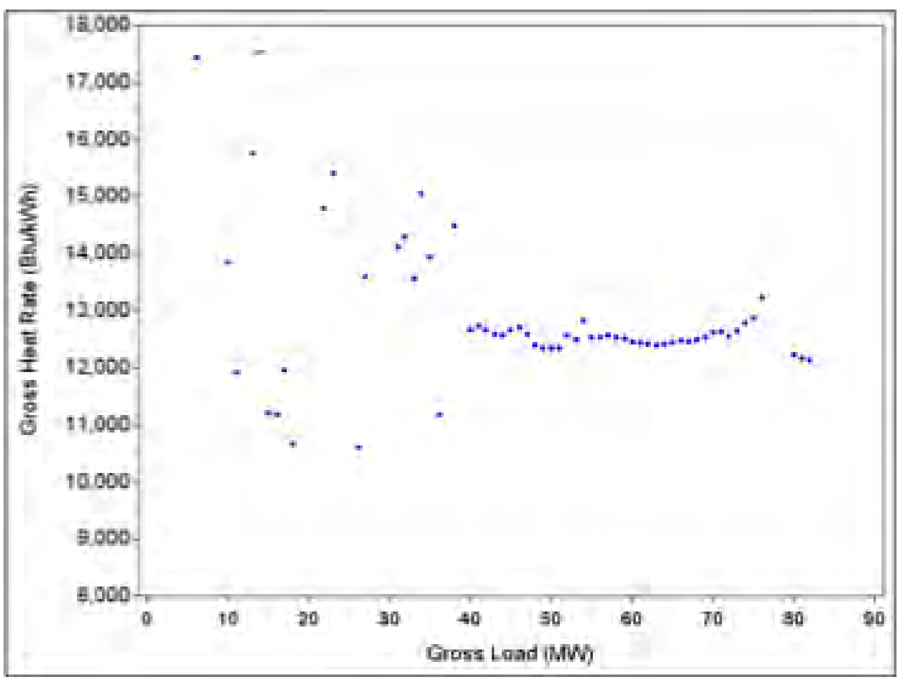


Figure A-2. Gross Plant Heat Rate vs. Load: Muscatine 8

COMMENTS OF WESTERN FARMERS ELECTRIC COOPERATIVE

On April 30, 2015, EPA convened a Small Business Advocacy Review ("SBAR") panel on its upcoming rulemaking, "Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014" (the "Federal Plan"). Western Farmers Electric Cooperative ("Western Farmers") appreciates the opportunity to participate in the SBAR panel process, but shares the concerns expressed by the Small Business Association in a letter dated May 8, 2015. Because EPA has not provided detailed information regarding the Federal Plan, the scope and content of the input Western Farmers can provide to EPA at this time is limited. Western Farmers developed these comments below to the best of its ability based on the limited information available, but may change its positions once EPA proposes the Federal Plan and additional information is made available. Additionally, these comments do not address the legal justification for EPA's proposed emission guidelines for existing sources (the "Emission Guidelines")[1] or the Federal Plan.

A. The Mass-Based Trading Option.

The Federal Plan should adopt a mass-based trading program that calculates each state cap using a reasonable load growth factor. Western Farmers believes that broad and inclusive trading is critical for the survival of small entities, and that a mass-based program would foster the broadest trading market. Because allowances would have a common and inherent value -- "a ton is a ton" -- sources covered by the Federal Plan could trade with sources in states covered by the Federal Plan or an approved Section 111(d) plan ("State Plans") that allow mass-based trading. In addition to creating a bigger allowance market, this flexibility would reduce the likelihood that companies with affected sources in multiple states would have to comply with inconsistent or conflicting requirements. The administration of compliance requirements is a significant burden on small entities, like Western Farmers, that do not have extensive staff. Any measure that streamlines potentially complex compliance requirements would be a significant benefit.

Although Westerns Famers supports a mass-based trading program, it is concerned that such a program could hamper Western Farmers' ability to meet increases in demand. Incremental increases in the cost of power are significant in the rural, and often resource-limited, populations served by Western Farmers and many other electric cooperatives. To the extent that increases in demand could be met by new, lower or zero emitting generation, it will take time for that generation, and associated infrastructure, to be developed. As Western Farmers explained in its comments on the proposed Emission Guidelines, the development of new generation and transmission takes approximately eight years, depending on the size and location of the projects. In the meantime, Western Farmers must be able to meet the needs of its consumers with low-cost, reliable power. Including a reasonable load growth factor in the calculation of the various mass-based caps would alleviate this concern.

[1] 79 Fed. Reg. 34,830 (June 18, 2014).

B. Key Flexibilities For Small Entities Under A Mass-Based Program.

Western Farmers urges EPA to provide small entities with the following flexibilities under a mass-based trading program:

- Allow States to Allocate Allowances. EPA should allow states to determine allowance allocations under the Federal Plan, consistent with the Agency's approach in prior cap-and-trade programs. States are best situated to understand local systems operations and identify constraints. EPA does not have this same expertise and, thus, should defer to the states. Western Farmers has significant concerns about EPA attempting to allocate or set aside allowances for sources with "special needs." While Western Farmers supports reserving allowances to address special needs *in addition* to the allowances permitted by the final mass-caps, the caps are likely to be so stringent that reservation of allowances would significantly increase the cost and scarcity of allowances. To the extent that an agency must "pick winners and losers" among affected sources, Western Farmers believes that states are better situated than EPA to make these difficult determinations.

- Credit Mass Reductions Through Agricultural Sequestration. EPA should allow small entities to achieve compliance through agricultural sequestration of carbon dioxide ("CO_2"). Many small entities, such as Western Farmers, are located in rural areas that have the potential to remove significant amounts of CO_2 from the atmosphere through agricultural sequestration programs. These programs can include no-till farming, grassland/rangeland management, riparian buffer repair along waterways, and forest management practices. By participating in an agricultural sequestration program, Western Farmers helped sequester 122,879,017 lbs of CO_2 between 2009 and 2013. Western Farmers believes that sequestration is consistent with the goals of the Emission Guidelines, and would not be excluded from a mass-based trading program based on EPA's proposed definition of the "best system of emission reduction." The effectiveness of agricultural sequestration in removing CO_2 from the atmosphere is quantifiable, verifiable, and demonstrated, and should be permitted under the Federal Program.

- Do Not Allow Allowances to be Retired. EPA should provide that allowances issued under the Federal Plan cannot be retired. When EPA failed to include a similar provision in implementation of the Acid Rain Program, third parties purchased allowances for the purpose of retiring them and making the trading program more stringent. The proposed Emission Guidelines, and presumably the Federal Plan, do not allow the same level of flexibility and phased implementation as the Acid Rain Program. In this context, any retirement of allowances could greatly increase the costs of what already will be an extremely costly program. This increased stringency is not justified by EPA's "best system of emission reduction" analysis and should be prohibited under the Final Rule.

C. The Rate-Based Trading Option.

EPA should not adopt a rate-based trading program. The extreme variation in the proposed state emission guidelines presents an insurmountable hurdle to the successful implementation of a rate-based trading program. Unlike allowances, which have an inherent, fixed value, the value of an emission rate credit would vary based on the location of the relevant entity. For example, plants in Kentucky and Virginia are part of the same Regional Transmission Operator ("RTO"), but the coal- and gas-fired plants in Virginia would need more credits per megawatt hour ("MWh") solely because of their location in a state with a more stringent emission rate goal -- even if the plants use the same technology and produce the same amount of CO_2. As a result, one MWh in Virginia is more costly than one MWh in Kentucky. Western Farmers is particularly concerned that variations in the value of credits could cause market distortions and make it difficult for affected sources to plan for compliance.

D. Key Flexibilities For Small Entities Under A Rate-Based Program.

In the event that EPA adopts a rate-based program, the Agency should provide small entities with the following flexibilities:

- Allow Credit Generation in the Pre-2020 Period. EPA should allow small entities to generate and bank emission credits, without deficits, prior to 2020. Small entities are less able to compete in market programs. Allowing small entities to generate and bank credits before the compliance period would offset this disadvantage and assist development of the credit market prior to an early in the compliance period. Allowing the early generation of credits also would benefit the environment by incentivizing continued operation of existing renewable energy resources, which otherwise may not be economical to operate, and the development of new renewable generation.

- Allow Credit for "Deemed Savings" for DSM Investments**.** EPA should allow small entities to generate credits from demand side management ("DSM") investments based on "deemed savings." Small entities, such as Western Farmers, have no way to guarantee that investments in DSM programs would be successful because many of these programs rely on the behavior of consumers. It is extremely difficult to influence consumer use because of behavioral obstacles. Small entities -- particularly electric cooperatives -- have less flexibility to mitigate the cost of any investments that do not provide the expected rate of return (in this instance, credits). Because electric cooperatives do not have shareholders, the entire cost of a partially successful program would be borne by rate payers. This risk is likely to deter investments in DSM programs and, thus, limit the compliance options available to small entities. Providing credit for "deemed savings" for DSM investments would mitigate this risk by giving small entities certainty about the rate or return on their investments. Without this provision, it is far less likely that small entities would invest in DSM programs because they could adequately guarantee their return on investment to make such programs feasible.

E. Additional Flexibilities For Small Entities.

EPA should provide for the following additional flexibilities to address challenges that would make compliance with the Federal Plan uniquely difficult for small entities:

- Allow Small Entities To Average Over the Entire Interim Period. EPA should allow small entities to determine compliance based on longer averaging periods. EPA has proposed to allow small entities to determine compliance based on a three year averaging periods. Western Farmers supports multi-year averaging periods, but does not believe this proposal goes far enough. Western Farmers believes the averaging periods should be longer, and that it would be reasonable for EPA to permit small entities to average emissions over the entire interim period. This longer planning horizon would provide entities with much needed flexibility to address potential stranded asset cost and reliability concerns.

- Extend the Compliance Period for Small Entities to 2035. EPA should extend the compliance period for small entities to 2035. Regardless of its final form, achieving compliance with the Federal Plan will require massive and abrupt changes in the electric generating, transmission and distribution systems. Small entities and the communities they serve are facing the threat of significant stranded assets. Western Farmers alone has approximately $250 million in debt associated with the Hugo Power Plant that would be put at risk by the Emission Guidelines, and, like other companies, is incurring new debt even today to comply with existing emissions regulations. Electric generating companies have not had sufficient time to recover the costs of these investments and, as a result, these costs likely will be imposed on consumers *in addition* to the higher cost of replacement natural gas generation and new associated transmission infrastructure. Extending the compliance period would allow small entities additional time to recover the cost of these investments and develop new infrastructure in a more cost-effective manner.

- Reduce Reporting Obligations for Units Less than 100 MW. EPA should reduce the reporting obligations for units smaller than 100 megawatts. Regardless of its form, the final Federal Plan will impose significant new regulatory burdens on small entities. Small entities have fewer resources to meet these burdens. Reducing the administrative cost of compliance would be a significant benefit to small entities and mitigate a small, but not insignificant, portion of the compliance costs imposed by the Federal Plan.

F. Additional Comments On The Federal Plan.

Western Farmers urges EPA to consider the following, additional comments on the Federal Plan:

- New Units Cannot Be Regulated Under the Federal Plan. EPA has requested comment on the role of "new units" under the Federal Plan. While Western Farmers supports allowing states the flexibility to include new units in a State Plan, EPA does not have the authority to subject non-Section 111(d) units, like new, modified, and reconstructed units, to regulation under both Sections 111(d) and 111(b). Subjecting these sources to requirements under both Sections 111(b) and 111(d) would contravene the clear statutory language in Section 111 and exceed the scope of EPA's authority under the Clean Air Act. Section 111(b) applies to the regulation of "new sources," while Section 111(d) applies to "existing sources." The two sections are mutually exclusive, as indicated by Section 111(a)(6), which states "existing source means any stationary source *other than a new source*." Therefore, the Federal Plan should not regulate "new sources."

- EPA Must Deviate From the Emission Guidelines to Address Remaining Useful Life. EPA has requested comment on methods to address "remaining useful life" in the Federal

Plan. Western Farmers does not foresee a construct that would allow EPA to address remaining useful life, as intended by the Clean Air Act, and maintain the proposed Emission Guidelines. Congress intended the consideration of remaining useful life to be undertaken with respect to the specific circumstances of individual sources. This assessment is not a balancing exercise relating to the overall emissions reductions from a source category, but rather consideration of whether remaining useful life and other factors applicable to "an existing source to which [a performance] standard applies" require relief from the general standard, either in the form of less stringent emission limits or longer compliance periods. To comply with this requirement in the context of a trading program, EPA would need to provide individual sources with more allowances or credits. However, EPA does not have the authority to make these adjustments at the expense of *other sources.* Thus, EPA could not address remaining useful life without increasing the total amount of allowances issued or credits generated under the program. Because EPA has indicated that it is unwilling to make such increases, there is no legal means for EPA to address remaining useful life under the Federal Plan.

***

Golden Spread Electric Cooperative, Inc.
A Touchstone Energy® Cooperative

5/28/2015

Submitted Electronically to:

Lanelle Bembenek Wiggins
RFA/SBREFA Team Leader
U.S. EPA- Office of Policy

RE: **Comments to Environmental Protection Agency SBAR Panel on Federal Plan Requirements for Greenhouse Gas Emissions from Electric Generation Units Constructed on or Before January 8, 2014 (CPP)**

I. Executive Summary

Golden Spread Electric Cooperative, Inc. (GSEC) welcomes this opportunity to submit comments to Environmental Protection Agency's (EPA) Small Business Advocacy Review Panel (SBAR) regarding EPA's plans to propose a Federal Implementation Plan (FIP) associated with the Agency's proposed Clean Power Plan (CPP).[1] GSEC is a non-profit electric generation and transmission (G&T) cooperative headquartered in Amarillo, Texas that supplies reliable wholesale electric power at the lowest feasible cost to its 16 member non-profit distribution cooperatives (Members). GSEC's Members serve about 223,000 retail electric meters, including residential, small business and agriculture customers.

GSEC's comments cover three basic points. First, GSEC urges EPA not to include in the FIP, restrictions on the utilization of natural gas simple cycle gas-fired units (NGSC) such as the restrictions in EPA's proposed New Source Performance Standards for greenhouse gas emissions from new, modified or reconstructed sources (GHG NSPS)[2]. These restrictions are arbitrary and could have the unintended consequence of limiting the use of renewables in areas where quick start generation is needed for back-up to renewable resources. Because of their ability to react quickly to swift changes in intermittent generation, such as wind, NGSC are vital to maintaining electric grid stability in areas that have significance intermittent generation, most notably wind and solar. NGSC are capable of starting and stopping multiple times a day with short notice, and can change ramp directions quickly.[3] Under EPA's proposed GHG NSPS, certain new, modified or reconstructed NGSC would be required to install combined cycle technology. However, NGCC are not well-suited to back-up intermittent sources of renewable energy, such as wind, due to their inherently longer start-up times and slower ramp rates. [4]

[1] 79 Fed. Reg. 34830 (June 14, 2014).
[2] 79 Fed. Reg. 1430 (January 8, 2014); 79 Fed. Reg. 34960 (June 18, 2014).
[3] SPP defines a "quick-start" resource as one that can be started, synchronized and inject energy within ten minutes of notification. GSEC's new "quick start" units can reach 70% capacity in 10 minutes and 100% capacity in 11 minutes from a cold start and can provide essential ancillary services to support wind generation. GSEC's fast start NGSC generation, located at Mustang Station, is capable of reaching full load and optimum output in in 30-36 minutes from a cold start.
[4] NGCC can require 150 minutes or more from a cold start to be at full load and optimum heat rate.

Reliance on NGCC when these units cannot in fact fulfill the quick start and quick ramping function needed to back-up wind and solar could result in the need to back down renewables to maintain grid stability. *Using NGCC to support renewable energy therefore could result in higher CO_2 emissions and decreased output from renewable energy sources, which can be avoided if NGSC are available and allowed to operate unrestricted as back-up power.*

Second, EPA should not rely on or mandate Heat Rate Improvements (HRI) for natural gas fired units in the FIP. EPA does not rely on HRI for gas units in Building Block 1 of the CPP proposal, and acknowledges that it does not have the information to support HRI for these units. EPA nevertheless requested comment in the CPP on whether HRI from gas units should be included, suggesting that HRI from units in "certain geographically isolated jurisdictions" could be an important approach to reducing CO_2 emissions.[5] EPA, however, does not explain why geographically isolated units have more potential for HRI than non-isolated units. Before EPA relies on HRI for NGSC and NGCC in the CPP and/or associated FIP, EPA must gather the necessary information and place it in the record and re-propose the rule to allow all stakeholders the opportunity to comment on EPA's data and assumptions.

Finally, GSEC supports the timing and reliability issues raised by the North American Electric Reliability Corporation (NERC), the Southwest Power Pool and the Electric Reliability Council of Texas (ERCOT), concerning EPA's proposed CPP. GSEC's primary corporate purpose is to supply reliable wholesale electric power to its Members at the lowest optimal prices. Therefore, GSEC requests that EPA either extend the implementation deadline, or work with the stakeholders to include a "reliability safety valve" in order to mitigate any potential reliability risks to the bulk power system and to recognize the time it takes to build the infrastructure improvements that are necessary to comply with the rule.

II. Overview of GSEC

GSEC is a non-profit electric G&T cooperative headquartered in Amarillo, Texas. Its corporate purpose is to supply reliable wholesale electric power at the lowest feasible cost to its Members while abiding by all applicable regulatory requirements. GSEC's Members serve about 223,000 retail electric meters serving their Member-Consumers located over an expansive area, including the South Plains, Edwards Plateau, and Panhandle regions of Texas (covering 24 percent of the state), portions of Southwestern Kansas and Southeastern Colorado, and the Oklahoma Panhandle (see Figure 1). GSEC serves electric loads and participates in both the multi-state Southwest Power Pool (SPP) and the Texas-specific Electric Reliability Council of Texas (ERCOT) grids. As shown in the figures below GSEC is located in an area with high wind (Figure 2) and solar (Figure 3) potential. Not only has this region contributed significantly to the nation's non-fossil fuel electric resources, the development of wind and solar generation in the GSEC footprint has provided local farmers and ranchers with the opportunity to lease real estate to wind and solar companies, improving the economic health of the region.

[5] *See* 79 FR at 34877.

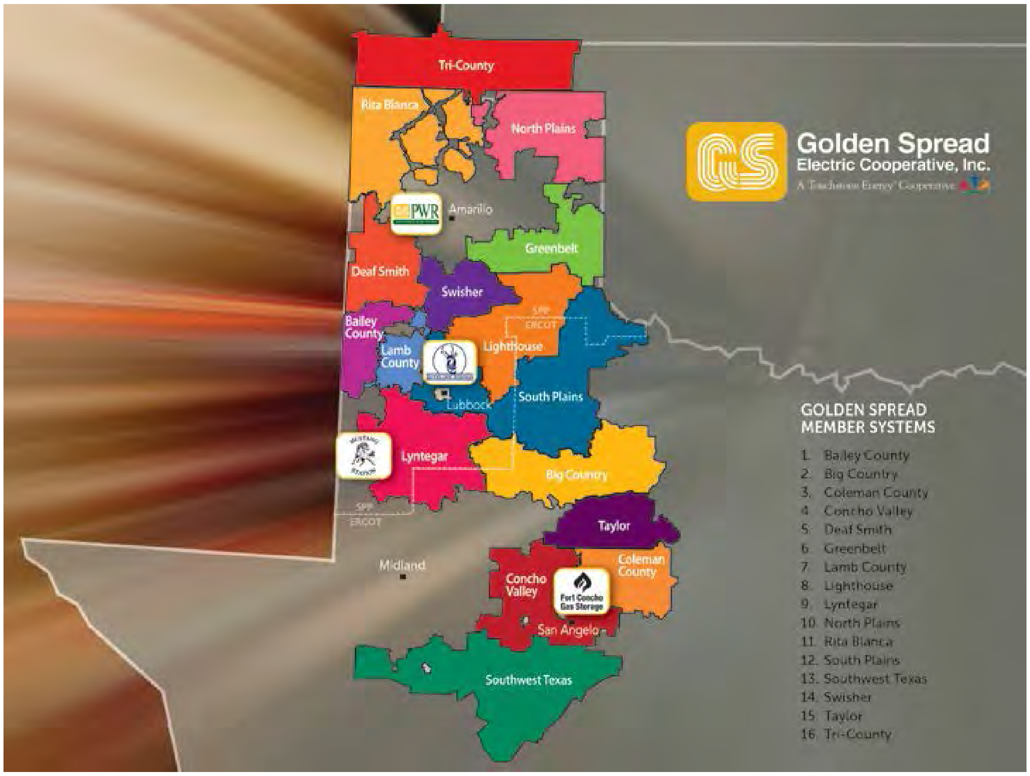


Figure 1 U.S. Detail Map of GSEC Service Area, by Member Systems

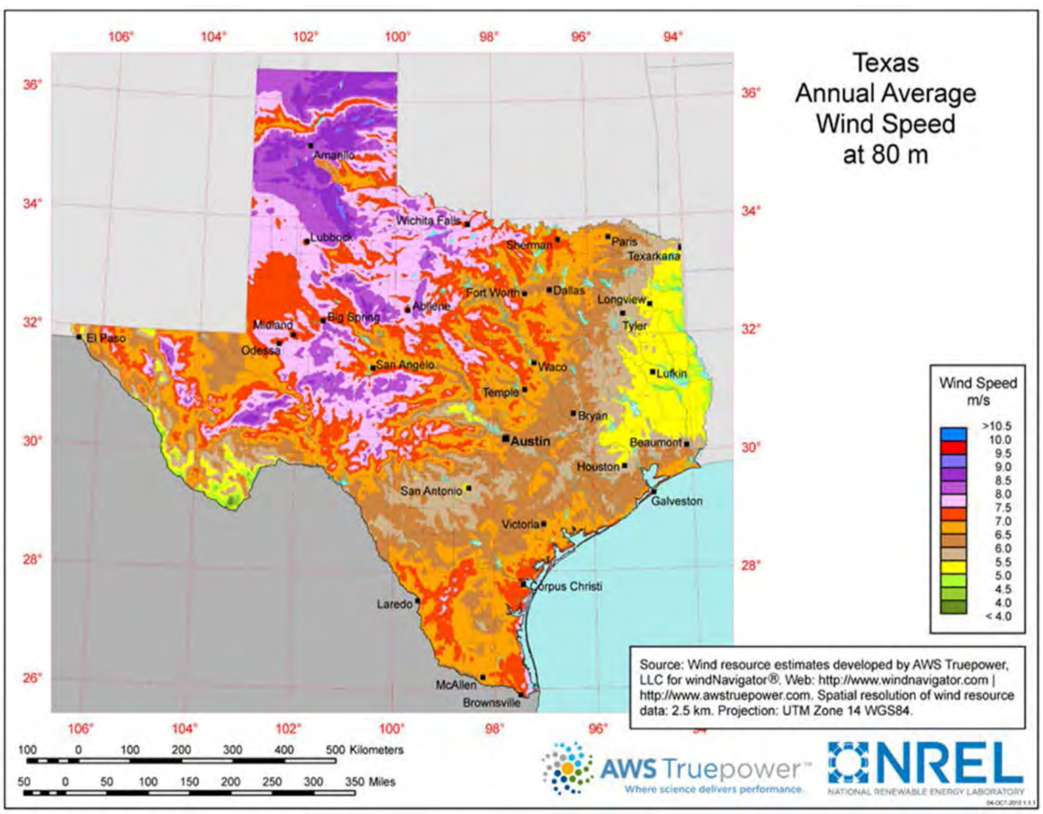


Figure 2 U.S. Annual Average Wind Speed at 80m Map: Color field represents average wind speed at 80 meters above ground level. The band of purple through the Great Plains indicates wind energy potential above 7.5 m/s.

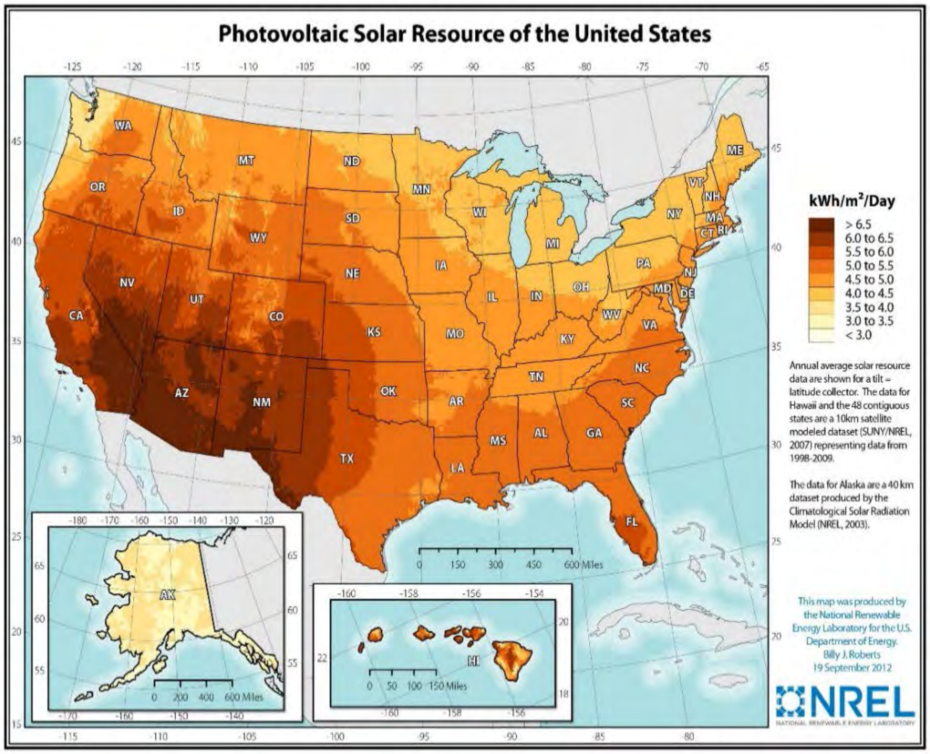


Figure 3 U.S. Solar Photovoltaic Resource Map, Using Data from 1998 to 2009 Regions with darker color indicate higher potential or photovoltaic solar power generation

The rate of regional wind energy development is significant and not expected to slow down any time soon. Figure 4 below illustrates both completed and announced renewable energy projects for the entire state. As can be seen, the majority of the completed and announced renewable energy projects in Texas are concentrated in GSEC Members' service area (Figures 4). As of April 1, 2015, Texas had a total of 14,208 megawatts (MWs) of installed wind capacity, a number that was the highest in the nation by a wide margin[6]. Solar energy development in the region is in its early stages, but is growing quickly.

Through its Competitive Renewable Energy Zone (CREZ) initiative, the state of Texas has made $6.9 billion investment in the state's natural wind power potential. In 2008, the Public Utility Commission of Texas (PUCT) issued Order No. 33672, which designated five CREZ lines for the generation of wind power and defined the transmission upgrades required to deliver the generated wind energy to Texas consumers (see Figure 5). The CREZ project was designed to add the transmission necessary to move wind-generated electricity in the CREZ locations to more heavily populated areas of Texas with higher energy needs, as shown in Figure 4. The PUCT estimated that the CREZ initiative will increase Texas' current level of wind generation transmission

[6] American Wind Energy Association, *Texas Wind Energy*, last updated end of Q1 2015, available at http://awea.files.cms-plus.com/FileDownloads/pdfs/Texas.pdf

capacity to 18,456 MW[7], and interconnection requests to date support this estimate. In fact, ERCOT has forecasted approximately 20,000 MW of wind generation on the system by 2017.[8]

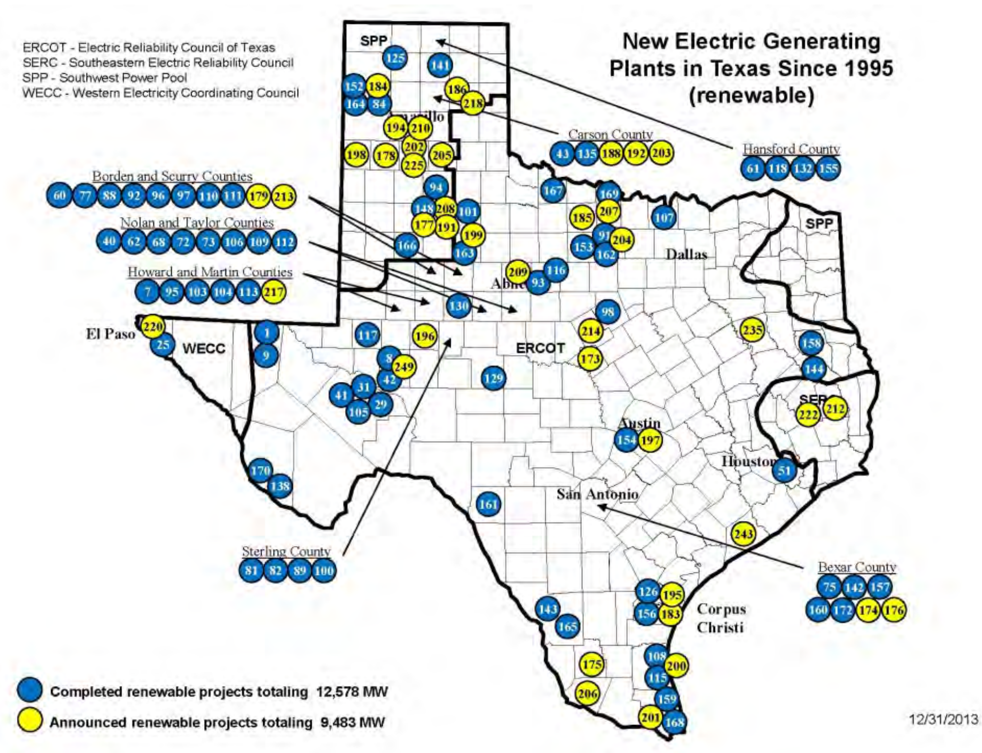


Figure 4 Completed and Announced Renewable Project in Texas as of 12/31/2013.

[7] Tex. Pub. Util. Comm'n, CREZ Transmission Program Information Center. *Program Overview*, available at http://www.texascrezprojects.com/overview.aspx; *see also*, Tex. Pub. Util. Comm'n, *Commission Staff's Petition for Designation of Competitive Renewable Energy Zones*, Docket No.33672,Order (Aug.15,2008), available at http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/33672_1412_593013.PDF.

[8] "The Competitive Renewable Energy Zones Process", Warren Lasher, ERCOT Director of System Planning, Aug. 11, 2014, available at http://energy.gov/sites/prod/files/2014/08/f18/c_lasher_qer_santafe_presentation.pdf.

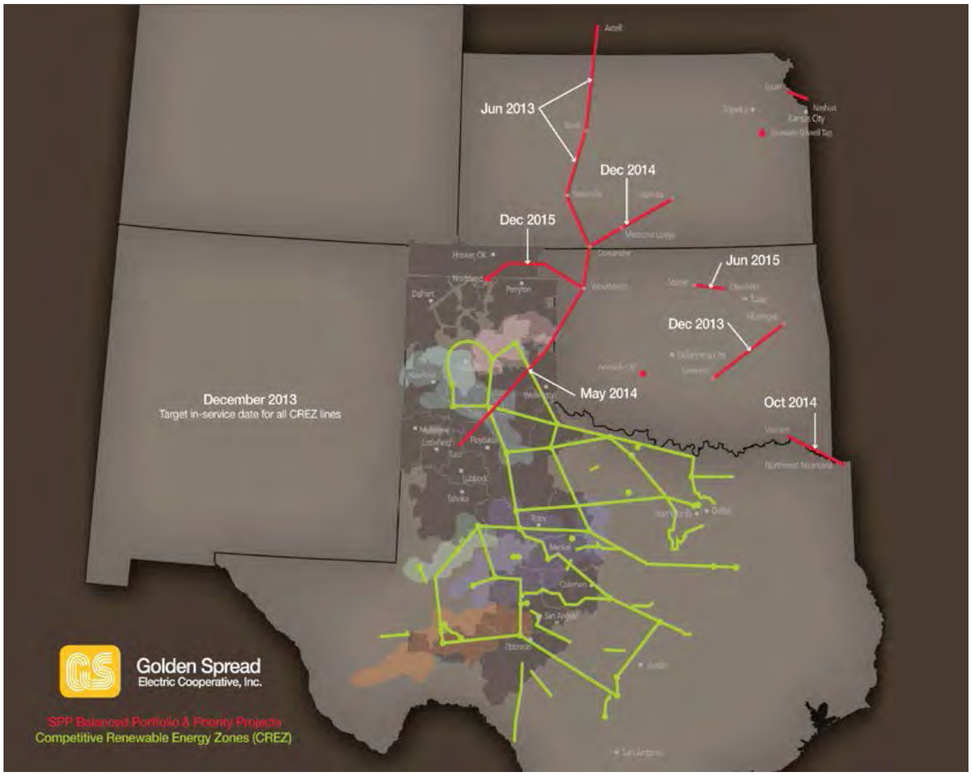


Figure 5 CREZ Lines

GSEC has significant interest in the outcome of EPA's proceeding as GSEC's assets include a natural gas combined-cycle (NGCC) unit subject to 40 CFR Part 60, Subparts GG and Db and three NGSC subject to 40 CFR Part 60, Subpart KKKK located at its Mustang Station in Denver City, Texas. GSEC's NGSC are well-suited to back-up intermittent wind generation due to their fast start capability, a role NGCC are not as well-suited to fulfill due to their inherently longer start-up times and maintenance issues associated with quick ramping and cycling. GSEC's existing NGSCs, located at Mustang Station, are capable of reaching full load and optimum output in 30-36 minutes from a cold start. Even the most advanced NGCC can take approximately 2.5 hours or more from a cold start to be at full load and optimum heat rate, while older NGCC can take significantly longer.

In addition, GSEC is also currently embarking on a capital expansion program to build sufficient generating capacity to meet its Members' load requirements. The construction of new generating units is necessary due to the termination of third-party purchase power agreements (a loss of approximately 830 MWs) and load growth on GSEC Members' systems. To help mitigate the intermittent nature of renewable energy, GSEC is pursuing a resource strategy which includes the use of wind power and the installation of "quick start" NGSC to help maintain grid stability and meet load when weather conditions are not conducive to wind energy production. SPP defines a "quick-start" resource as one that can be started, synchronized and inject energy within ten minutes of notification.[9] When the wind stops blowing, GSEC's NGSC new units will be able to reach 70% capacity in 10 minutes and 100% capacity in 11 minutes from a cold start.

Because of its renewable-rich area of operation, GSEC is at the forefront of the integration of renewable generation on the electric grid. As renewables assume a larger role in the nation's energy

[9] Southwestern Power Pool. *SPP Integrated Market Place Protocols*, rev. 16.0a (Aug. 2, 2013).

portfolio, GSEC believes NGSC operation will become even more important to support grid reliability and to maximize the utilization of carbon-free generation.

III. GSEC'S RECOMMENDATIONS FOR EPA'S CPP FIP

A. NGSC Play an Important Role in Supporting Renewable Energy and their Utilization Should Not be Restricted in EPA's CPP or Associated FIP

Operational restrictions on NGSC, such as these proposed by EPA in its GHG NSPS, could limit the use of NGSC, resulting in grid reliability issues or the need to reduce wind or solar generated power to maintain grid stability, ultimately inhibiting the integration of renewable energy into the grid. Under EPA's proposed GHG NSPS, NGSC that meet the definition of new, modified or reconstructed under the rule, and supply more than 1/3 of its potential electric output and more than 219,000 MWh net electric output to the grid per year, will be required to install combined cycle technology if they are to meet the standard. No basis for the 1/3 limit is provided, and the assumption appears to be that NGCC will be relied upon to provide the quick start services needed to support the electric grid when renewable generation is not available. However, NGCC are not well-suited to "follow" or back-up, wind generation due to their inherently longer start-up times and difficulty in promptly ramping up to provide energy to the grid. In fact, as discussed in further detail below, using a NGCC to support renewable energy could result in higher CO_2 emissions (which goes against the initiative of the CPP), as at times it is necessary to curtail wind generation so that resources with slower start times (*e.g.*, NGCC) can stay on at minimum output, thus ensuring their availability for rapid ramp-up when the wind drops off. [10] Additionally, NGCCs typically do not reach their optimal heat rate unless they are operated at or near full capacity; heat rates when units operate at lower generation levels, can be significantly higher.

NGSCs, on the other hand, are well-suited to complement and support wind and solar energy production because of their fast start capabilities. Even the most advanced NGCC in operation, can take approximately 2.5 hours (or even longer) to be at full load and optimum heat rate from a cold state; while older NGCCs can take even longer. GSEC's existing NGSC at Mustang Station, can take 30-36 minutes to be at 100% output while more advanced NGSC can take as little as 10 minutes to reach 70% of maximum output and 11 minutes to reach full power on some NGSCs.[11] This makes NGSCs ideal to support intermittent renewable energy.

In GSEC's CPP comments submitted to EPA on December 1, 2014 (GSEC CPP Comments), GSEC provides an example of how an operational restriction on NGSC utilization can result in overall *higher CO_2 emissions*. Those examples are included as Attachment 1 and 2, to these comments. Attachment 1 represents a fall or spring day in an electric power market with high wind, higher NGCC and limited NGSC generation capacity, which is the likely scenario if NGSC are only allowed to operate at less than 1/3 of their electric output capability. The main chart shows the typical demand requirement for an entire day, indicating a load increase starting around 6:00 a.m. and generally peaking around 5:00 p.m. The standard configuration for the NGCC unit is two gas combustion turbines matched to one steam turbine (2X1). It is also possible to operate that equipment in an alternative configuration using only one of the two combustion units with the

[10] In comments already submitted to EPA, GSEC has rebutted claims that NGCC are well-suited to back-up renewable sources of energy. See, *Golden Spread's Response to Siemens' Comments on EPA's Comments on EPA's Proposed Existing Unit Rule Docket No.* ID No. EP-HQ-OAR-2013-0603, December 1, 2014.

steam turbine (1X1). Both configurations are shown in Attachments 1 and 2, and minimum load for each of the operating configurations is shown as well. The minimum load shown for a NGCC unit is the lowest load level at which it can be operated and still be available to supply back-up power if wind generation suddenly decreases. As explained in the testimony of Mr. Thomas E. Burke, GSEC's Director, Regulatory and Transmission Policy (see Attachment 3 to GSEC's CPP Comments), if NGCC are to be used as a back-up to wind generation, they must be kept operating at or above minimum load levels to maintain grid stability and reliability.

Attachment 1 shows that at the end of the 24 hour period, 2,665 MWh of wind energy has been curtailed from the total wind output possible in order to keep the NGCC generation operating at minimum loads so that they may be readily available to provide back-up power if required. Assuming CO_2 emission rates of 1,000 lbs/MWh for a NGCC turbine (as proposed by EPA in the GHG NSPSs) and 1,300 lbs/MWh for a NGSC turbine, the total CO_2 emissions from both the NGSC and NGCC generation is 27,164,500 pounds. The second scenario, shown in Attachment 2, likewise represents the same fall or spring day with the same load demand and wind power generation potential as used in Attachment 1. The main difference between the two scenarios is that the Attachment 2 scenario includes more NGSC capacity assuming unrestricted NGSC generation. In the end, this scenario would result in the installation of more NGSC than in the Attachment 1 scenario in which NGCCs are used and the operation of NGSC are restricted.

Due to NGSC's fast start capability, *no minimum load output is required*. When more NGSC turbine generation capacity is available, as shown in the Attachment 2 scenario, only 110 MWh of wind generation is curtailed. Additionally, lower total CO_2 emissions resulted with the increased use of the wind energy/NGSC combination. At the end of the 24 hour period, the total combined NGSC and NGCC CO_2 emissions are 25,339,000 lbs., which is 1,825,500 lbs. less CO_2 than was emitted under the Attachment 1 scenario in which NGCCs are used and the operation of NGSC are restricted.

Thus, in areas with high wind capacity, reducing the use of NGSC and relying more on NGCC resources can result in an increase, rather than a decrease, of CO_2 emissions. Within the actual operating environment of electric grids, taking full advantage of the flexibility of operation provided by NGSC turbines on a grid-wide basis *may also result in greater integration of renewable resources into the regional electrical profile.*

In a 2013 report, published by the California Independent System Operator (CAISO) (see Attachment 3), CAISO discusses resources needed to ensure green grid reliability. In "What the duck curve tells us about managing a green grid", in referring to the situation when minimum power levels are maintained even though the electricity is not needed, as "overgeneration", CAISO states:

> "Because the ISO must continuously balance supply and demand, steps must be taken to mitigate over generation risk. These steps include increasing exports, expanding resource capabilities, and requiring renewable generation curtailment. The ability to export power depends on the needs of neighboring entities and balancing agreements. The available resources must evolve to include capabilities to start and stop multiple

times per day and start with short notice from a zero or low electricity operating levels." [12]

Because their faster ramp rates and startup times, as compared to a NGCC, NGSC are the reasonable "flexible resource" choice to support increased renewable energy integration.

Furthermore, in Attachment 1 to GSEC's CPP Comments, Mr. George E. Hess, former Vice President of Production for GSEC, explains in his testimony that cycling NGCC offline to back-up renewable generation, can cause deteriorating effects to the Heat Recovery Steam Generator (HRSG) and steam turbine components. According to the United States Department of Energy, National Energy Technology Laboratory, when fossil fuel resources are operated in this manner "the heat rate is degraded".[13] This can result in higher fuel consumption per MWh and higher emissions.

The important role NGSC play to support wind generation is also discussed in an affidavit provided by Lanny D. Nickell, Vice President of Engineering for SPP, provided in GSEC's CPP Comments, Attachment 2. In fact, a review of SPP Dispatch Data from 2013 – 2014 (see Attachment 1 of Mr. Nickell's affidavit) by SPP and GSEC confirms a significant increase in the utilization of NGSCs since the implementation of SPP's Integrated Marketplace, which also correlates with an increase in output of wind generation from 2013 to 2014. [14] SPP believes that this correlation demonstrates that NGSCs are being relied upon to support variable wind in the SPP Integrated Marketplace.[15]

In addition and as explained in Mr. Nickell's affidavit and Mr. Burke's testimony[16], the characteristics of organized wholesale electric markets, such as the SPP and ERCOT in which GSEC operates, limit the operation of NGSC. NGSC have higher operating (i.e., fuel) costs than that of many other available sources (i.e. nuclear, coal, NGCC and renewables). Mr. Nickell testified that due to these increased operating costs, NGSC are and will continue to be the last to be dispatched unless there is a good reason to dispatch them out-of-merit (i.e., instead of lower cost sources) for support of grid reliability (i.e., to support variable wind sources).

EPA appears to understand this economic reality as it pertains to market forces. In EPA's GHG Abatement Measures Technical Support Document (TSD) the agency states that "[i]n order to maintain least-cost dispatch, the units with the lowest variable costs will be called upon first, then other units (with higher variable costs) will be called upon sequentially, such that total system demand is met."[17] In short, NGSC units are and will continue to be dispatched last. Therefore,

---

[12] California Independent System Operator. "Fast Facts: What the Duck Curve Tells Us about Managing a Green Grid," page 3, Document I.D. CommPR/HS/10.2013 (2013). Accessed via http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

[13] U.S. Dept. of Energy, Office of Fossil energy, *Impact of Load Following on Power Plant Cost and Performance: Literature Review and Industry Interviews*, (Oct. 1, 2012), DOE/NETL-2013/1592 (emphasis added), 1, 41, available at http://www.netl.doe.gov/energy-analyses/pubs/410_01_32_FR_Rev1_20121010.pdf.

[14] *See* GSEC's CPP Comments, Testimony of Mr. Nickell, SPP, at Attachment 2 and Testimony of Mr. Burke, GSEC, at Attachment 3 .

[15] *See* GSEC CPP Comments, Testimony of Mr. Nickell, SPP, at Attachment 2.

[16] *See* GSEC's CPP Comments, Testimony of Mr. Nickell, SPP, at Attachment 2 and Supplemental Testimony of Mr. Burke, GSEC, at Attachment 3.

[17] EPA GHG Abatement Measures TSD at 49.

there is no need for EPA to mandate that States regulate these sources to achieve targets set forth in the CPP, nor should EPA include such a mandate in the FIP.

For the above-stated reasons, GSEC believes that any restriction on NGSC utilization through EPA's CPP and/or associated FIP, is unnecessary and, furthermore, could actually impede accomplishment of EPA's CO_2 reductions targets in the proposed CPP.

B. EPA Should Not Mandate HRI for NGSC or NGCC in its CPP FIP

In its CPP proposal, EPA acknowledges that it has not collected and studied the requisite information to support HRI for NGCCs and NGSCs. Furthermore, EPA concluded that there is only a small potential for reduction in CO_2 emissions from HRI at NGCC and NGSC as compared to other fossil fuel-fired electric generation units (EGUs) [18]. For these reasons, EPA decided not to rely on HRI for NGCC and NGSC in Building Block 1 of the CPP proposal, and should not mandate HRI in the FIP.

Although EPA concludes that it does not have the information to support including NGCC and NGSCs in Building Block 1, EPA requests comment on whether HRI from non-coal technologies *should* be included. EPA states that in "certain geographically isolated jurisdictions, HRI from non-coal fossil fuel-fired EGUs could be a more important potential approach to reducing CO_2 emissions." [19] However, EPA does not explain why geographically isolated units have more potential for HRI than similar units in areas that are not isolated. GSEC is not aware of why isolated jurisdictions would have more HRI potential for NGCCs and NGSCs. In any event, GSEC submits that NGCCs and NGSCs (whether geographically isolated or not) should not be subject to HRI through Building Block 1 and any associated CPP FIP.

Turning first to NGCC, EPA acknowledges in Appendix A of the TSD "GHG Abatements Measures" that the agency does not have the unit-specific detailed design information on existing individual NGCCs that would be needed to make a detailed assessment of the HRI potential via best practices upgrades for each NGCC unit. EPA states that it would be possible for EPA to conduct a "variability analysis" of NGCC historical hourly heat rate data (as was done for coal-steam EGUs). EPA explains, however, that the various NGCC configurations in use and the historically lower capacity factors of the NGCC fleet (less run time per start, and more part load operation) would require a more complicated analysis and would also result in more uncertainty than in the coal-steam analysis. In addition, the analysis would be further limited by the fact that only one-third of the NGCC fleet has historically reported complete load data (combustion turbine and steam turbine generator) to EPA. GSEC supports the conclusion that a variability analysis for NGCC would suffer from too much uncertainty that would be further compounded by a lack of available reported data. Because of the uncertainly and limited reported data, any conclusions about HRI for these units that would result from a "variability analysis" would not be "adequately demonstrated" as required to support an NSPS.[20]

For the purposes of the TSD, EPA does try to gauge the potential for HRI reduction for NGCC. This was done through discussions with EPA staff familiar with NGCC design and operation and

[18] *See* EPA GHG Abatement Measures TSD at A-3-A-6.
[19] *See* 79 FR at 34877.
[20] EPA may *only* promulgate a NSPS for emissions of air pollutants that "reflects the degree of emission limitation *achievable* through the application of the best system of emission reduction which . . . the Administrator determines has been *adequately demonstrated.*" 42 U.S.C. §7411(a)(1).

consultation with power engineering firms and NGCC suppliers. Without further detail, EPA gauges that the HRI potential for NGCC may be 2-3% at most on a sustained basis.[21] We note that this HRI estimate does not appear to have been based on information from owners and operators of NGCCs and may be inflated over what is achievable. Based on GSEC's experience operating these units we believe that the HRI potential of NGCC is actually less than 1%.[22]

EPA states that HRI methods would only be applicable to the combustion turbine portion of the power cycle (i.e., the HRSG, the steam turbine-generator, and the heat rejection system). EPA concludes that the HRI potential is much lower than that from a coal unit because the NGCC is simpler insofar as it (1) uses gaseous fuels, (2) does not have back end scrubbers, (3) uses less parasitic power, (4) has no air heater leakage, and (5) has no feed water heaters. In addition, an NGCC flue gas exit temperature is typically already much lower than in a coal-steam unit. GSEC agrees with these observations.[23]

EPA also notes that regularly scheduled maintenance practices are the most effective methods to achieve HRI that could be applied to NGCC and that these maintenance practices are likely already being applied across most of the fleet. EPA explains that any HRI would apply to critical components in the hot expansion side of the unit that are exposed to the products of combustion fuel and air that contain small amounts of corrosive elements at very high temperatures. EPA believes that these critical components necessarily require regular removal and/or refurbishment to maintain efficiency and that industry follows the manufacture's maintenance recommendations. To increase efficiency owners are incented to follow these practices. EPA correctly concludes that these most effective maintenance practices are already being applied and therefore it is not necessary to include HRI for NGCC in Building Block 1.[24]

GSEC concurs with EPA that any opportunity for heat rate improvement exists at the steam turbine. Also the greatest loss in the performance of the combustion turbine portion of the NGCC is due to the physical degradation that occurs in proportion to its hours of operation and number of starts. It has long been the practice of NGCC owners, including GSEC, to closely follow the manufacturer's maintenance recommendations that regularly restore efficiency and reliability of the turbine. GSEC agrees that regularly scheduled maintenance practices are the most effective HRI for these units. Because they are already being applied and were being applied by the industry in the baseline year there is no opportunity for further HRI through this rulemaking. GSEC appreciates that EPA recognizes that these practices are already being employed by the industry and that additional meaningful HRI is not available for these units.[25]

With regard to NGSC, EPA notes that these units operate to provide peaking capacity and this role requires them to be inherently less efficient. That being said, even more so than NGCC, EPA concludes that any reduction in CT heat from these units can only provide a nominal reduction in CO_2 emissions (much less than 1%). EPA also points out that NGSC provides an extremely small

[21] EPA GHG Abatement Measures TSD at A-5.
[22] *See GSEC's CPP Comments,* Testimony of Mr. Hess, at Attachment 1.
[23] *See* id.

[24] *See* EPA GHG Abatement Measures TSD at A-4 - A-5.
[25] *See* id.

amount of total fossil-fuel generation, only about 1% of the total.[26] Although NGSC usage may increase as a source of back-up generation in portions of the country that are increasing their reliance on renewable sources of energy, including Texas, any NGSC usage increase would not be significant as compared to the nation's fossil fuel generation to warrant application of HRI to these units. As with NGCC, owners also are incented to follow maintenance protocols to ensure efficiency.

GSEC agrees with EPA that HRI for NGSC is not necessary. NGSC usage is already restricted by the forces of the wholesale power market except when needed to provide peaking capacity.[27] Therefore, as noted by EPA, any application of HRI could only provide, at most, a minuscule reduction in CO_2 emissions. Again, the industry regularly maintains these units as recommended by the manufacturer of the unit (and this practice was employed during the baseline period).[28]

GSEC supports EPA's position that NGCCs and NGSCs should not be included as BSER in Building Block 1 of the CPP. GSEC submits that before EPA mandates HRI for NGSC or NGCC in its proposed CPP and/or associated FIP, EPA must gather the necessary information, place it in the record, and re-propose the rule to allow all stakeholders the opportunity to comment on EPA's data and assumptions. EPA itself has stated that it currently lacks the appropriate data to make an informed decision on the matter. If EPA changes its position in this regard, the basis and underlying support for such a reversal must be presented to the public for comment.

C. EPA's FIP Should Address Reliability Concerns Due to Short Compliance Timeline

As currently proposed, the EPA's proposed CPP establishes an interim emission rate from 2020-2029 for each state, before arriving at the final target in 2030. Individual states are required to submit compliance plans to EPA by June 2016, unless an extension is granted. This means that the regulated community could have only 3 ½ years after finalization of state plans to develop and implement a compliance strategy. As described in more detail below, 3 ½ years is not sufficient time to plan, develop, permit, construct, interconnect, and test new generation facilities required for compliance, placing the reliability of the bulk power system at risk.

1. Transmission And Generation Needs for CPP Compliance

a. NERC's CPP Assessment

The North American Electric Reliability Corporation (NERC), the mission of which is to ensure the reliability of the North American bulk power system, issued its assessment of the CPP on April, 2015 (NERC CPP Assessment). [29] In its assessment, NERC takes into account what Regional Transmission Organizations (RTOs)/Independent System Operators (ISOs) will need to do in order to comply and largely avoids making any inference about potential reliability concerns associated with CPP implementation. However, NERC's impact modeling of the CPP estimated that somewhere between 41-43 gigawatt (GW) of oil, gas, and coal capacity will be retired by the 2020 interim goal, with an additional 42-44 GW of capacity retiring by the 2030 goal. Based on current

[26] *See* EPA GHG Abatement Measures TSD at A-5 and 6.
[27] *See* Testimony of Mr. with SPP at Attachment 2 and the Testimony of Mr. Burke with GSEC at Attachment 3.
[28] *See* Testimony of Mr. George Hess, former Vice President of Production for GSEC at Attachment 1.
[29] *Potential Reliability Impacts of the EPA's Proposed Clean Power Plan*, NERC, April, 2015

market analytics, NERC assessed that much of the generation lost would be replaced by natural gas turbines and renewables. According to NERC's CPP Assessment, in order to accommodate the new generation being brought on, many RTO/ISOs would need up to 16 years of time to supply adequate transmission and natural gas pipeline infrastructure.

b. SPP CPP Reliability Assessment

In October of 2014, the SPP released its Reliability Impact Assessment (SPP CPP Reliability Assessment) revealing that the SPP faces major reliability hurdles in order to meet the interim goal. The reserve margin in the SPP region will fall to 4.7% in order to meet the interim 2020 goal, and continue to drop to negative 4.0% by 2024.[30]

This capacity deficiency is exacerbated in the Texas Panhandle area, (which includes GSEC's Members service territory), where according to SPP modeling, there will be a negative 25% reserve margin by 2024. [31] This low margin stems from the retirement of coal plants in order to meet the interim deadline. As a result of such an extreme deficiency in generation, the SPP will be at high risk of experiencing voltage collapse and rolling blackout conditions. Moreover, the southwestern portion of the SPP region has significant transmission constraints; so, resources outside of the Texas Panhandle are unlikely to be accessible to GSEC to mitigate the risk of voltage collapse and rolling blackouts.

In the SPP CPP Reliability Assessment, the SPP also developed a corresponding timeline for infrastructure and market design activities needed to facilitate compliance with the CPP.[32] Figure 15 below, from the SPP Reliability Assessment, illustrates possible durations involved with each applicable process and activity. These timelines were developed based on available SPP data from transmission planning, development, and construction activities and data from members and other public sources. As illustrated in Figure 15, extra high voltage facilities which would be needed to support this dramatic change in generation resources identified in the SPP's long-term ITP study could take up to 8 ½ years to be placed in service.

[30] *Reliability Impact of the EPA's Proposed Clean Power Plan,* SPP, 2014
[31] *Ibid*
[32] *SPP Clean Power Plan Regional Compliance Assessment,* SPP, April, 2015

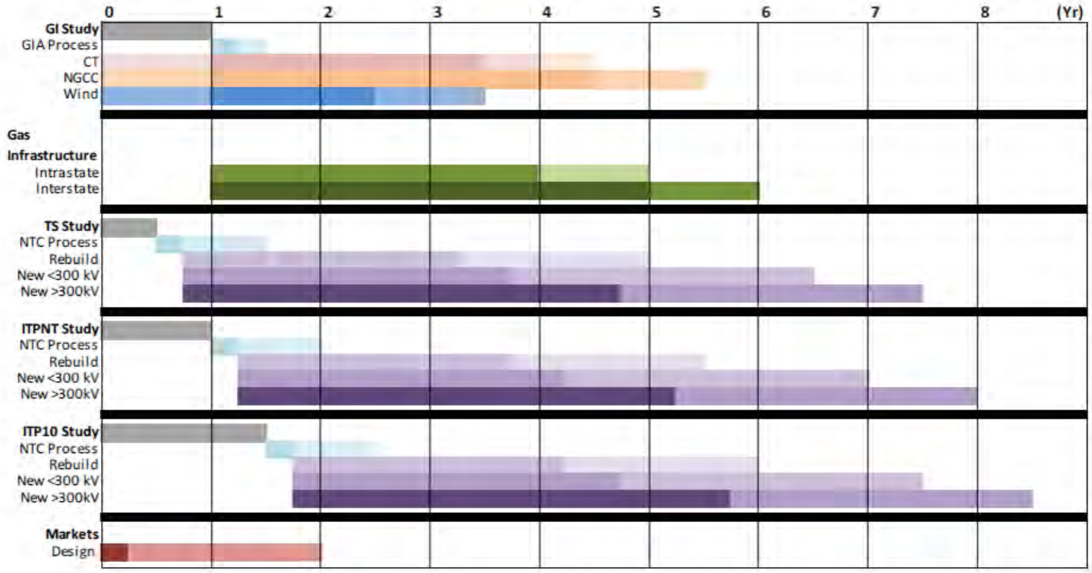


Figure 15: Timelines for Various Processes

c. ERCOT Analysis of the Impacts of the CPP

On November 17, 2014 ERCOT issued its Analysis of the Impacts of the CPP (ERCOT CPP Analysis), where the story is similar. The models calculated the effect of 3,300 and 5,700 MW of coal-fired capacity retirement across various carbon cost adder scenarios. However, these represented the lower bound of potential coal retirements. Furthermore, it did not include other environmental regulation impacts, such as the Mercury and Air toxics Standard, the Regional Haze program, the 316(b) Cooling Water Intake Structures Rule and the coal ash rules. When ERCOT includes these and other capacity/operating factors, the lower bound of coal retirements gets as high as 8,700 MW.

ERCOT's CPP modeling indicates a dramatic change in its generation outlook. By 2029, as much as 29% of generation could come from renewables, the majority of which is solar. These renewable resources will be supported by quick start and fast-ramping units, including primarily NGSC, in order to ensure a reliable supply of energy during sudden renewable capacity loss.

However, the planning for this additional generation mix will take time and money. It takes a minimum of 5 years advanced notice to plan and develop major transmission projects in ERCOT. To give a comparison, the competitive renewable energy zone ("CREZ") initiative to build transmission to deliver wind energy from wind-rich West Texas to the major population centers, undertaken in 2008 pursuant to a Texas legislative mandate, and is almost complete today, 7 years later. [33]ERCOT's study shows that these transmission lag times will cause serious reliability concerns for major ERCOT metroplexes as coal fired generation goes offline. Furthermore, ERCOT notes that this lag does not include the natural gas pipeline planning and construction needed for the natural gas turbines. According to ERCOT, by the time it has overcome these

[33] *Impacts of the Clean Power Plan,* ERCOT, November, 2014

hurdles and reached compliance in 2029, as much as $24 billion in capital costs will have been passed along to the consumer, an estimate 77% greater than the business-as-usual model.

2. Potential Solutions

The issues raised by NERC, SPP and ERCOT present a significant challenge to 111d. GSEC supports NRECA's position advocating an adjustment to the compliance dates to allow the regulated community more time for careful and responsible planning and to then allow the construction of the needed generation and transmission resources. If the proposed timeline is finalized as is, it is possible that with the compressed time frame only the quickest and easiest solutions would be explored, resulting in ineffective solutions implemented at higher than necessary costs. As discussed above, ERCOT and SPP have carefully studied the implementation of 111(d) and concluded that the costs to comply with the CPP in their regions is both costly and likely to require more time that permitted by the interim 2020 deadline. GSEC also supports NRECA proposed a "reliability safety valve" which would help ensure that reliability is not jeopardized by the implementation of the CPP.

GSEC appreciates the opportunity to comment on the EPA's development of the CPP FIP.
Please feel free to contact me with any questions at jhayden@gsec.coop or (806) 349-5250.

Sincerely,

J. Jolly Hayden

J. Jolly Hayden
Chief Operating Officer
Golden Spread Electric Cooperative, Inc.

ATTACHMENT 1

Typical Fall/Spring Day in Electric Power Market with High Wind and CC Capacity

Assumptions:

Generation (MW)	Max Load Output (MW)	Minimum Load Output (MW)
Nuclear	250	250
Coal	2,000	1,350
SC	1,350	0
CC 2X1	1,600	750
CC 1X1	1,100	650
Wind	1,100	0

Table 1.

Hour Ending	Demand	Wind	Nuclear	Coal	Gas SC	Gas CC 2X2	Gas 1X1	Max Wind Potential	Wind Curtailed
1	2700	450	250	1350	0	0	650	850	400
2	2700	450	250	1350	0	0	650	800	350
3	2700	450	250	1350	0	0	650	825	375
4	2700	450	250	1350	0	0	650	835	385
5	2700	450	250	1350	0	0	650	715	265
6	2900	500	250	1500	0	0	650	650	150
7	2975	450	250	1600	25	0	650	600	150
8	3125	475	250	1750	0	0	650	500	25
9	3265	315	250	1900	150	0	650	415	100
10	3485	385	250	2000	200	0	650	450	65
11	3475	325	250	2000	250	0	650	325	0
12	3700	350	250	2000	350	750	0	350	0
13	3775	345	250	2000	330	850	0	345	0
14	3915	300	250	2000	415	950	0	300	0
15	4090	265	250	2000	525	1050	0	265	0
16	4235	235	250	2000	675	1075	0	235	0
17	4500	200	250	2000	950	1100	0	200	0
18	4450	225	250	2000	860	1115	0	225	0
19	4135	300	250	2000	585	1000	0	300	0
20	3990	375	250	2000	315	1050	0	375	0
21	3650	415	250	1800	185	1000	0	415	0
22	3250	400	250	1600	50	950	0	400	0
23	2950	400	250	1500	0	800	0	525	125
24	2700	400	250	1350	0	0	700	675	275
Total CC CO_2 emissions in lbs			**19,540,000**	**Total MWh**	**5,865**	**11,690**	**7,850**	**11,575**	**2,665**
Total CT CO_2 emissions in lbs			**7,624,500**						
Total Combined CO_2			**27,164,500**						

1. 1,000 lbs CO_2 lb/MWh assumption for NGCC taken from the EPA's proposed New Unit NSPS Rule.

2. 1,300 lbs CO_2/MWh assumption was used for NGSC. However, this is not to suggest that GSEC believes this is an appropriate NGSC emission standard. EPA must collect a supportable CEMS data set for NGSC units and analyze it to establish a standard that is adequately demonstrated after allowing for notice and comment on a proposal.

Typical Fall/Spring Day in Electric Power Market with High Wind and SC capacity
Assumptions:

Generation (MW)	Max Load Output (MW)	Minimum Load Output (MW)
Nuclear	250	250
Coal	2,000	1,350
SC	2350	0
CC 2X1	1000	375
CC 1X1	700	300
Wind	1,100	0

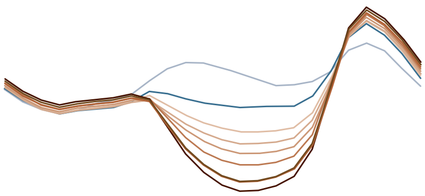
Table 2.

Hour Ending	Demand MW	Wind	Nuclear	Coal	Gas SC	Gas CC 2 x 2	Gas CC 1 x 1	Max Wind Potential	Wind Curtailed
1	2700	800	250	1350	0	0	300	850	50
2	2700	800	250	1350	0	0	300	800	0
3	2700	800	250	1350	0	0	300	825	25
4	2700	800	250	1350	0	0	300	835	35
5	2700	715	250	1350	0	0	385	715	0
6	2950	650	250	1500	125	0	425	650	0
7	2975	600	250	1600	200	0	325	600	0
8	3125	500	250	1750	250	0	375	500	0
9	3265	415	250	1900	275	425	0	415	0
10	3485	450	250	2000	285	500	0	450	0
11	3475	325	250	2000	350	550	0	325	0
12	3700	350	250	2000	450	650	0	350	0
13	3775	345	250	2000	480	700	0	345	0
14	3915	300	250	2000	565	800	0	300	0
15	4090	265	250	2000	675	900	0	265	0
16	4235	235	250	2000	750	1000	0	235	0
17	4500	200	250	2000	1000	1050	0	200	0
18	4450	225	250	2000	975	1000	0	225	0
19	4135	300	250	2000	635	950	0	300	0
20	3990	375	250	2000	515	850	0	375	0
21	3650	415	250	1800	350	835	0	415	0
22	3250	400	250	1600	200	800	0	400	0
23	2950	525	250	1500	50	0	625	525	0
24	2700	675	250	1350	0	0	425	675	0
Total CC CO_2 emissions in lbs			**14,770,000**	**Total MWh**	**8,130**	**11,010**	**3,760**	**11,575**	**110**
Total CT CO_2 emissions in lbs			**10,569,000**						
Total Combined CO2			**25,339,000**						

1. 1,000 lbs CO_2 lb/MWh assumption taken from the EPA's proposed New Unit NSPS Rule.
2. 1,300 lbs CO_2/MWh assumption was used for NGSC. However, this is not to suggest that GSEC believes this is an appropriate NGSC emission standard. EPA must collect a supportable CEMS data set for NGSC units and analyze it to establish a standard that is adequately demonstrated after allowing for notice and comment on a proposal

California ISO
Shaping a Renewed Future

FAST FACTS



What the duck curve tells us about managing a green grid

The electric grid and the requirements to manage it are changing. Renewable resources increasingly satisfy the state's electricity demand. Existing and emerging technology enables consumer control of electricity consumption. These factors lead to different operating conditions that require flexible resource capabilities to ensure green grid reliability. The ISO created future scenarios of net load curves to illustrate these changing conditions. Net load is the difference between forecasted load and expected electricity production from variable generation resources. In certain times of the year, these curves produce a "belly" appearance in the mid-afternoon that quickly ramps up to produce an "arch" similar to the neck of a duck—hence the industry moniker of "The Duck Chart".

Energy and environmental goals drive change

In California, energy and environmental policy initiatives are driving electric grid changes. Key initiatives include the following:

- 33 percent of retail electricity from renewable power by 2020;
- greenhouse gas emissions reduction goal to 1990 levels by 2020;
- regulations in the next 4-9 years requiring power plants that use coastal water for cooling to either repower, retrofit or retire;
- policies to increase distributed generation; and
- an executive order for 1.5 million zero emission vehicles by 2025.

New operating conditions emerge

The ISO performed detailed analysis for every day of the year from 2012 to 2020 to understand changing grid conditions. The analysis shows how real-time electricity net demand changes as policy initiatives are realized. In particular, several conditions emerge that will require specific resource operational capabilities. The conditions include the following:

- **short, steep ramps** – when the ISO must bring on or shut down generation resources to meet an increasing or decreasing electricity demand quickly, over a short period of time;
- **overgeneration risk** – when more electricity is supplied than is needed to satisfy real-time electricity requirements; and
- **decreased frequency response** – when less resources are operating and available to automatically adjust electricity production to maintain grid reliability.

Green grid reliability requires flexible resource capabilities

To reliably operate in these conditions, the ISO requires flexible resources defined by their operating capabilities. These characteristics include the ability to perform the following functions:

- sustain upward or downward ramp;
- respond for a defined period of time;
- change ramp directions quickly;
- store energy or modify use;
- react quickly and meet expected operating levels;
- start with short notice from a zero or low-electricity operating level;
- start and stop multiple times per day; and
- accurately forecast operating capability.

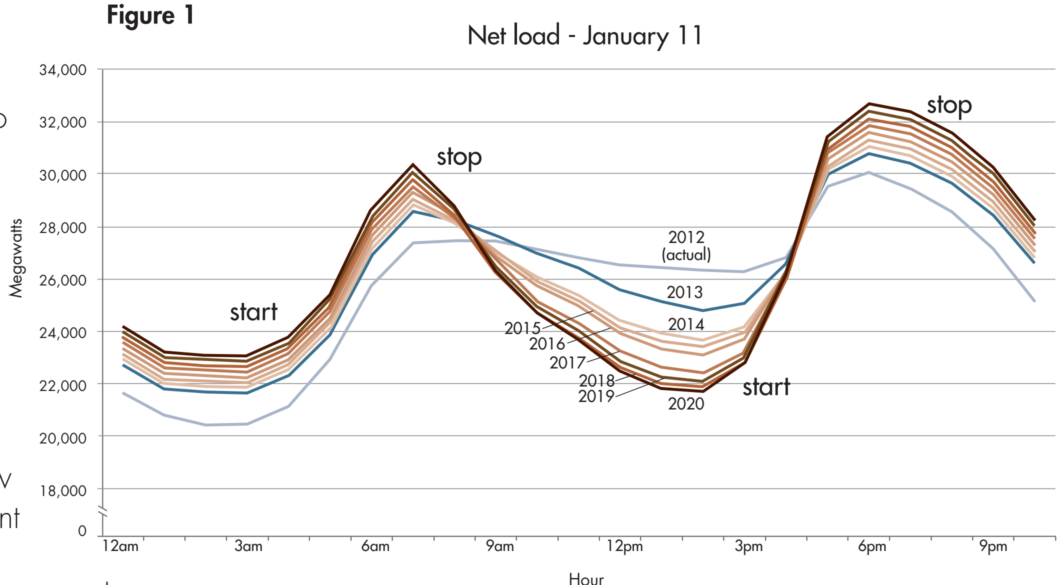
Reliability requires balancing supply and demand

The net load curves represent the variable portion that ISO must meet in real time. To maintain reliability the ISO must continuously match the demand for electricity with supply on a second-by-second basis. Historically, the ISO directed conventional, controllable power plant units to move up or down with the instantaneous or variable demand. With the growing penetration of renewables on the grid, there are higher levels of non-controllable, variable generation resources. Because of that, the ISO must direct controllable resources to match both variable demand and variable supply. The net load curves best illustrate this variability. The net load is calculated by taking the forecasted load and subtracting the forecasted electricity production from variable generation resources, wind and solar. These curves capture the forecast variability. The daily net load curves capture one aspect of forecasted variability. There will also be variability intra-hour and day-to-day that must be managed. The ISO created curves for every day of the year from 2012 to 2020 to illustrate how the net load following need varies with changing grid conditions.

Ramping flexibility

The ISO needs a resource mix that can react quickly to adjust electricity production to meet the sharp changes in electricity net demand. **Figure 1** shows a net load curve for the January 11 study day for years 2012 through 2020. This curve shows the megawatt (MW) amounts the ISO must follow on the y axis over the different hours of the day shown on the x axis. Four distinct ramp periods emerge.

Figure 1



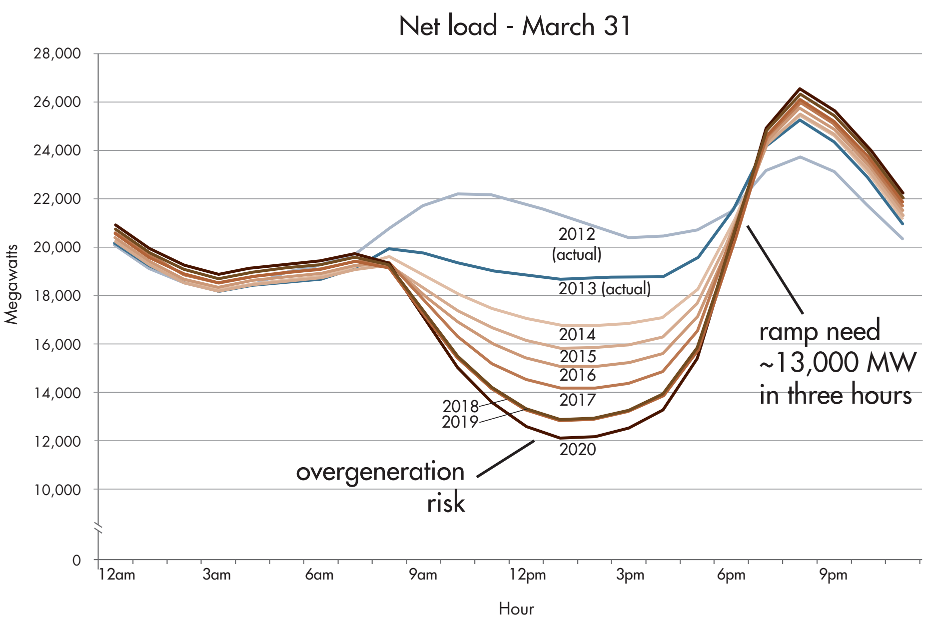
The first ramp of 8,000 MW in the upward direction (duck's tail) occurs in the morning starting around 4:00 a.m. as people get up and go about their daily routine. The second, in the downward direction, occurs after the sun comes up around 7:00 a.m. when on-line conventional generation is replaced by supply from solar generation resources (producing the belly of the duck). As the sun sets starting around 4:00 p.m., and solar generation ends, the ISO must dispatch resources that can meet the third and most significant daily ramp (the arch of the duck's neck). Immediately following this steep 11,000 MW ramp up, as demand on the system deceases into the evening hours, the ISO must reduce or shut down that generation to meet the final downward ramp.

Flexible resources needed

To ensure reliability under changing grid conditions, the ISO needs resources with ramping flexibility and the ability to start and stop multiple times per day. To ensure supply and demand match at all times, controllable resources will need the flexibility to change output levels and start and stop as dictated by real-time grid conditions. Grid ramping conditions will vary through the year. The net load curve or duck chart in **Figure 2** illustrates the steepening ramps expected during the spring. The duck chart shows the system requirement to supply an additional 13,000 MW, all within approximately three hours, to replace the electricity lost by solar power as the sun sets.

Overgeneration mitigation

Figure 2: The duck curve shows steep ramping needs and overgeneration risk



Overgeneration happens when more electricity is supplied than is needed to satisfy real-time electricity requirements. The ISO experiences overgeneration in two main operating conditions. The first occurs as the ISO prepares to meet the upcoming upward ramps that occur in the morning and in the late afternoon. The existing fleet includes many long-start resources that need time to come on line before they can support upcoming ramps. Therefore, they must produce at some minimum power output levels in times when this electricity is not needed. The second occurs when output from any non-dispatchable/must-take resource further increases supply in times of low electricity need, typically in the nighttime hours. Historically, this condition was most likely to occur in the early morning hours when low demand combines with electricity and generation brought on line to prepare for the morning ramp. The duck curve in **Figure 2** shows that overgeneration is expected to occur during the middle of the day as well.

Because the ISO must continuously balance supply and demand, steps must be taken to mitigate over generation risk. These steps include increasing exports, expanding resource capabilities, and requiring renewable generation curtailment. The ability to export power depends on the needs of neighboring entities and balancing agreements. The available resources must evolve to include capabilities to start and stop multiple times per day and start with short notice from a zero or low electricity operating levels. The resource mix would also benefit from resources with energy storage capabilities and demand side response capabilities to help meet real-time system conditions.

Reliable grids have automated frequency response

System frequency measures the extent to which supply and demand are in balance. To ensure reliability, system frequency must be managed in a very tight band around 60 hertz. When an unexpected event occurs that disrupts the supply-demand balance, such as a loss of a generator or transmission line, frequency is impacted. These events do not allow time for manual response and balance is maintained through automated equipment. Conventional generation resources include frequency-sensing equipment, or governors, that automatically adjust electricity output within seconds in response to frequency to correct out-of-balance conditions.

Part of the renewable integration analysis conducted by the ISO uncovered concerns about frequency response capabilities due to the displacement of conventional generators on the system. The 2020 33% studies show that in times of low load and high renewable generation, as much as 60% of the energy production would come from renewable generators that displace conventional generation and frequency response capability. Under these operating conditions, the grid may not be able to prevent frequency decline following the loss of a large conventional generator or transmission asset. This situation arises because renewable generators are not currently required to include automated frequency response capability and are operated at full output (they can not increase power). Without this automated capability, the system becomes increasingly exposed to blackouts when generation or transmission outages occur.

Policy needed for flexible resources

To reliably manage the green grid, the ISO needs flexible resources with the right operational characteristics in the right location. The ISO is actively engaged in policy efforts to build awareness of the new grid needs. Working with the industry and policymakers, the ISO is collaborating on rules and new market mechanisms that support and encourage the development of flexible resources to ensure a reliable future grid.

www.caiso.com | 250 Outcropping Way, Folsom, CA 95630 | 916.351.4400

CommPR/HS/10.2013

American
Public Power
Association

2451 Crystal Drive
Suite 1000
Arlington, VA 22202-4801

Ph: 202.467.2900
Fax: 202.467.2910
www.PublicPower.org

Small Business Advocacy Review Panel Comments on EPA's Federal Plan Requirements for Greenhouse Gas Emissions from Electric Generating Units Constructed on or Before January 8, 2014

Submitted Electronically to:
Lanelle Wiggins RFA/SBREFA Team Leader U.S. EPA
Office of Policy

By

Alex Hoffman
Director of Energy Services
and
Carolyn Slaughter
Director of Environmental Policy

May 28, 2015

I. Introduction

The American Public Power Association (APPA) appreciates the opportunity to participate in the Small Business Advocacy Review (SBAR) panel on the Environmental Protection Agency's (EPA) Federal Plan for Regulating Greenhouse Gas Emissions from Electric Generating Units (EGU). APPA filed an extensive set of comments on December 1, 2014, outlining our concerns with EPA's Proposed Rule (or Proposal) under section 111(d) of the Clean Air Act (CAA) to reduce emissions of carbon dioxide (CO_2) from fossil fuel-fired EGUs.[1,2] In those comments, APPA raised legal and substantive concerns, in addition to the recommendations we believe will improve the affordability and workability of the Proposed Rule[3]. In general, we believe the Proposed Rule imposes inequitably distributed additional costs to consumers, threatens electric system reliability, and forces an over-reliance on a single fuel—natural gas—to generate electricity. APPA and its members recommend EPA address the flaws in the proposed rule as enumerated in our comments and given during the Small Business Advocacy Review (SBAR) panel.

EPA's Proposal has the ability to rapidly transform the utility sector in an unprecedented manner. Its impact on small public power utilities could be enormous, forcing them to prematurely shut down EGUs and strand costs, resulting in significant price increases for consumers. As specified in federal statute, EPA must carefully consider the impact of its proposed rules, such as the soon-to-be-proposed Federal Plan (FP), will have on small entities and must act to lessen the burden of the rule on those small entities.[4] The Regulatory Flexibility Act (RFA), and the amendments made to it by the Small Business Regulatory Enforcement Fairness Act (SBREFA), were enacted by Congress to provide small entities a meaningful voice in major federal rulemakings. SBREFA's primary goals are to encourage "effective participation" of small business in the federal regulatory process and create a more cooperative regulatory environment among businesses in the federal regulatory process,[5] as well as create a more cooperative regulatory environment among agencies and small businesses that is less punitive and more solution oriented.[6] Section 609 of SBREFA envisions that small business panels will review "any material the agency has prepared in connection with this chapter," including information required to be part of the initial regulatory flexibility analysis.[7] This information typically includes descriptions of significant alternatives to the proposed rule, differing compliance or reporting requirements or timetables that take into account the resources available to small entities, and the clarification, consolidation or simplification of compliance and reporting requirements for small entities.[8]

Acting EPA Assistant Administrator Janet McCabe announced on January 15, 2015, the Agency's plan to issues a proposed FP to implement EPA's proposed section 111(d) rule and provide interested states with a model for compliance with its Proposal. Subsequently, EPA announced plans to convene a SBAR panel on April 30, 2015, and held its first preliminary teleconference on May 1, 2015, an in-person meeting on May 14, 2015, and a follow up teleconference on May 19, 2015. The unusually short

---

[1] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830 (June 18, 2014) (Proposed Rule or Proposal).
[2] 42 U.S.C. § 7411 (2012).
[3] Comments of the American Public Power Association (APPA) on EPA's Section 111(d) Proposed Rule for Carbon Dioxide Emissions from Existing EGUs EPA-HQ-OAR-2013-0602 (December 1, 2014).
[4] 42 U.S.C § 111(d)(1)(B)
[5] 5 U.S.C §203 (3)
[6] 5 U.S.C § 203 (6)
[7] 5 U.S.C §609(b)(4); see also 5 U.S. C §603(b)(3),(4) and (5) and 603(c)
[8] 5 U.S.C §603(c)

timeframe did not provide Small Entity Representatives (SERs) with sufficient time to offer meaningful comment and participation in the SBREFA process. APPA believes EPA has not prepared sufficient materials to convene this SBAR panel. The Agency has not provided the panel members with information on the potential impacts of this proposed rule, nor has it provided SERs with the necessary information upon which to discuss alternatives and provide recommendations to EPA, as required by SBREFA.

II. Who is APPA?

APPA is the national service organization representing the interests of not-for-profit, publicly owned electric utilities throughout the United States. More than 2,000 public power utilities provide over 15 percent of all kilowatt-hour sales of electricity to consumers and do business in every state except Hawaii. All APPA utility members are Load Serving Entities (LSEs), with the primary goal of providing customers in the communities they serve with reliable electric power and energy at the lowest reasonable cost, consistent with good environmental stewardship. This orientation aligns the interests of APPA utility members with the long-term interests of the residents and businesses in their communities. Collectively, public power utilities serve more than 48 million customers.

III. Number and Types of Small Entities Affected by a Section 111(d) Federal Plan

More than 90 percent of public power utilities qualify as small businesses under SBREFA. Under SBA regulations, small entities are defined as governments of cities, counties, towns, townships, villages, school districts, or special districts, with populations of 50,000 or less. SBREFA was enacted by Congress to provide small entities a meaningful voice in major federal rulemakings. Among the Act's goals is to encourage the "effective participation" of small businesses in the federal regulatory process and to create a more cooperative regulatory environment among agencies and small businesses that is less punitive and more solution orientated . Table 1 is illustrative of affected public power communities that service communities with less than 50,000 people and have greater than 25 MW of nameplate capacity fossil fuel fired generation.

Owner code	Utility Name	State	Adjusted Cap (MW)
13470	City of New Madrid - (MO)	MO	650
8449	Henderson City Utility Comm	KY	405
1647	City of Bethany - (MO)	MO	404
3702	Clarksdale Public Utilities	MS	361.6
12208	City of McPherson - (KS)	KS	330.4
17177	City of Sikeston - (MO)	MO	261
5335	City of Dover - (DE)	DE	196.3
8245	City of Hastings - (NE)	NE	176.98
6779	City of Fremont - (NE)	NE	170
19804	City of Vero Beach - (FL)	FL	158.4

2144	Town of Braintree - (MA)	MA	138.97
9130	Hutchinson Utilities Comm	MN	125.8
55772	Paducah Power System	KY	120
3271	Central Nebraska Pub P&I Dist	NE	115.7
7634	City of Greenville - (TX)	TX	109.9
11701	City of Marquette - (MI)	MI	104.7
7483	City of Grand Haven - (MI)	MI	100.9
3355	City of Chanute	KS	98.8
9645	Jamestown Board of Public Util	NY	96.3
6775	Village of Freeport - (NY)	NY	91.8
3486	Chillicothe Municipal Utils	MO	90
14194	City of Orrville - (OH)	OH	84.5
14653	PUD No 1 of Pend Oreille County	WA	82.5
8884	Terrebonne Parish Consol Gov't	LA	78.9
13488	New Ulm Public Utilities Comm	MN	78.5
21048	Wyandotte Municipal Serv Comm	MI	78.4
7651	Greenwood Utilities Comm	MS	76.5
5625	Easton Utilities Comm	MD	72.4
11204	Los Alamos County	NM	65.25
3892	City of Coffeyville - (KS)	KS	62.7
11142	City of Logansport - (IN)	IN	61
11740	City of Marshfield - (WI)	WI	60.4
14381	City of Painesville	OH	58.48
12927	Morgan City - (LA)	LA	58.3
11732	City of Marshall - (MO)	MO	57.3
2548	City of Burlington Electric - (VT)	VT	55.25
11251	Loup River Public Power Dist	NE	54
5336	City of Dover - (OH)	OH	52.58
8567	City of Higginsville - (MO)	MO	51.6
9275	Indianola Municipal Utilities	IA	50
3400	City of Chaska	MN	49
15202	City of Ponca City - (OK)	OK	48
13485	New Smyrna Beach Utilities Commission	FL	48
42652	Quincy-Columbia Basin Irr Dist	WA	47.982
42653	East Columbia Basin Irr Dist	WA	47.982
42654	South Columbia Basin Irr Dist	WA	47.982
2439	City of Bryan - (OH)	OH	45.84
5571	East Bay Municipal Util Dist	CA	45.6
10152	City of Kennett - (MO)	MO	44.5
20315	City of Wellington - (KS)	KS	44
15137	City of Plaquemine - (LA)	LA	44
2010	City of Bountiful	UT	43.6
20737	Willmar Municipal Utilities	MN	42

19798	City of Vernon	CA	41.8
3113	City of Carthage - (MO)	MO	41.8
10393	PUD No 1 of Klickitat County	WA	41.5
24558	City of Escanaba	MI	40.9
20214	Waverly Municipal Elec Utility	IA	40.719
20813	City of Winfield - (KS)	KS	40.7
7095	City of Geneseo - (IL)	IL	40.519
20259	City of Webster City - (IA)	IA	40.5
7292	Glencoe Light & Power Comm	MN	39.5
17783	City of Spencer - (IA)	IA	39.425
6949	City of Gardner - (KS)	KS	39.2
15388	City of Princeton - (IL)	IL	37.9
17271	City & Borough of Sitka - (AK)	AK	37.7
10210	Ketchikan Public Utilities	AK	37.6
965	Atlantic Municipal Utilities	IA	37.074
10056	City of Kaukauna	WI	36.8
14840	City of Peru - (IL)	IL	36.5
15095	City of Piqua - (OH)	OH	36.3
14839	City of Peru - (IN)	IN	36.3
20382	City of West Memphis - (AR)	AR	36
8543	Hibbing Public Utilities Comm	MN	35.9
13444	City of New Hampton - (IA)	IA	35.725
309	City of Algona - (IA)	IA	35.553
12625	City of Minden - (LA)	LA	35.4
4538	Crisp County Power Comm	GA	34.7
21158	City of Zeeland - (MI)	MI	34.3
15229	City of Poplar Bluff - (MO)	MO	34.1
21095	Public Serv Comm of Yazoo City	MS	34.1
16217	Village of Rockville Centre - (NY)	NY	33.8
20824	Village of Winnetka - (IL)	IL	33.4
1050	City of Azusa	CA	33.3
6839	City of Fulton - (MO)	MO	33.2
14446	Paragould Light & Water Comm	AR	33.1
11611	City of Maquoketa - (IA)	IA	32.4
1009	City of Austin - (MN)	MN	31.9
15321	City of Pratt- (KS)	KS	31.5
10633	City of Lamar - (CO)	CO	31.5
3329	Borough of Chambersburg	PA	31.2
26616	North Slope Borough Power & Light	AK	31.1
14229	City of Ottawa - (KS)	KS	30.7
16440	City of Russell - (KS)	KS	30.7
10830	City of Lebanon - (OH)	OH	30.6
998	City of Augusta - (KS)	KS	30.2

20180	City of Waterloo - (IL)	IL	30.2
3710	City of Clay Center - (KS)	KS	29.9
7096	City of Geneva- (IL)	IL	29.5
1366	City of Bay City - (MI)	MI	28
14645	City of Pella - (IA)	IA	28
6205	City of Farmington - (MO)	MO	28
12298	City of Menasha - (WI)	WI	28
19150	Trenton Municipal Utilities - (MO)	MO	27.5
15686	Village of Rantoul - (IL)	IL	27.2
17845	City of Springville - (UT)	UT	27
16179	Rochelle Municipal Utilities	IL	26.9
11460	City of Macon - (MO)	MO	26.8
7222	City Of Gillette	WY	26.726
9603	City of Jackson - (MO)	MO	26.3
19883	City of Virginia - (MN)	MN	26.2
18277	City of Sullivan - (IL)	IL	25.4

Source: ABB Velocity Suite, accessed May 4, 2015

There are numerous small public power utilities that have only one generation resource under 100 MW of nameplate capacity today. The implications for those communities under the Proposed Rule and subsequent FP are particularly grave; those public power utility owners/operators do not have the flexibility to rely on other units. Moreover, these single coal plant owners supply electricity to other small businesses in their community, such as local grocery stores, gas stations, regional hospitals, and assorted service industries that often form the basis of the local economy in their respective communities. Overburdening these small public power utilities would result in substantial cost increases to other local small businesses that are already economically distressed. Table 2 is illustrative of public power communities with only a single coal unit.

Table 1 Single Unit Coal Facilities

Utility Code	Utility Name	State	Fuel Type	Capacity (MW)
1050	City of Azusa [9]	CA	Coal	34.1325
1192	City of Banning (CA)[10]	CA	Coal	22.755
4280	Conway Corporation	AR	Coal	72
5742	Eldridge City Utilities Commission	IA	Coal	8.94875
7222	City of Gillette	WY	Coal	26.726
8449	Henderson City Utility Commission	KY	Coal	405
8543	Hibbing Public Utilities Commission	MN	Coal	35.9
9286	Illinois Municipal Elec Agency	IL	Coal	432.9

[9] Capacity reflects partial ownership in San Juan Generating Station Unit 3
[10] Capacity reflects partial ownership in San Juan Generating Station Unit 3

9667	City of Jasper- (IN)	IN	Coal	14.5
10704	Lansing Broad of Water and Light	MI	Coal	529.7
11235	Lafayette Public Power Authority	LA	Coal	279
11833	Municipal Energy Agency of MS	MS	Coal	43.2
12807	Michigan South Central Power Authority	MI	Coal	55
12840	Town of Montezuma- (IN)	IN	Coal	3.8745
13470	City of New Madrid- (MO)	MO	Coal	650
14194	City of Orrville (OH)	OH	Coal	84.5
14268	City of Owensboro (KY)	KY	Coal	445.3
15989	City of Richmond (IN)	IN	Coal	93.9
17177	City of Sikeston- (MO)	MO	Coal	261
18715	Texas Municipal Power Authority	TX	Coal	453.5
19883	City of Virginia	MN	Coal	30.2
20382	City of West Memphis – (AR)	AR	Coal	36
21704	MSR Public Power Agency	CA	Coal	159.34
24431	Utah Municipal Power Agency[11]	UT	Coal	100
26253	Louisiana Energy& Power Authority	LA	Coal	111.6
40576	Intermountain Power Agency	UT	Coal	1640
40603	Wyoming Municipal Power Agency	WY	Coal	50.7
40604	Heartland Consumers Power District	SD	Coal	140.58
5000	Northern Illinois Municipal Power Agency	IL	Coal	141.28
50002	Kentucky Municipal Power Agency	IL	Coal	141.28
	TOTAL			6, 4212
	All public power coal capacity			34,539

Source: Energy Information Administration, Form EIA-860-2012 data

The first thing EPA can do to assist small public power utilities, short of withdrawing and re-proposing the rule, would be to adopt APPA's recommendations for changes in the final rule. Those include providing additional time for states to develop their plans, fixing the numerous errors and adjusting the unrealistic assumptions in the building block computations, providing full credit for early action, and eliminating the interim reduction goal would provide more flexibility and make the rule more workable. Moreover, since EPA has indicated its intent to make the proposed FP be similar to an approvable state plan, these benefits and added flexibility would presumably transfer into any FP issued by EPA.

[11] Capacity reflects partial ownership in San Juan Generating Station Unit 3 and Hunter Unit 2

A. Exclude Reciprocating Internal Combustion Engines (RICE) and Simple Cycle Natural Gas (SCNG) Units

Assuming the FP is applicable to any boiler, integrated gasification combined cycle (IGCC), or combustion turbine meeting the requirements in the Proposal, a section 111(d) FP should exclude simple cycle natural gas (SCNG) turbines and reciprocating internal combustion engines (RICE). RICE units are used for emergency power, voltage support, and demand response, and provide reliability to the Bulk Power System. Furthermore, the preamble to EPA's proposed section 111(b) rule suggests SCNG units are not affected units if they sells less than one-third of their potential electric output to the grid. The section 111(d) proposal would cover (or exempt) the same types of EGUs that were in operation or had commenced construction on or before January 8, 2014.

IV. Potential Reporting, Recordkeeping, and Compliance Requirements

Monitoring and recordkeeping requirements have significant impacts on small entities. Such requirements are problematic because small entities do not have the financial resources, manpower, or technical expertise needed to operate electronic reporting and tracking systems that could be used to track emissions, as well as energy efficiency (EE) and renewable energy (RE) credits. The FP should seek to lessen the impact of reporting and recordkeeping requirements on small entities by reducing such obligations for EGUs that have a name plate capacity of less than 100 MW. Unfortunately, EPA's presentation materials did not specifically discuss any particular reporting structure or credit allocation tracking system. Therefore small entities are unable to offer any meaning full comment on this point. At a minimum, EPA should consider utilizing existing reporting and tracking platforms rather than creating new ones.

V. Related Federal Rules

A. New Source Review (NSR)

The Proposed rule offers heat rate improvements under building block 1 as a means to reduce CO_2 emissions within a facilities fence line. EPA explains that these heat rate improvements can be achieved by "installing and using equipment upgrades…such as extensive overhaul or upgrade of major equipment (turbine or boiler) or replacing existing components with improved versions."[12] Historically EPA has targeted these sorts of projects as triggers for compliance with the Clean Air Act's New Source Review (NSR) requirements. The Agency's policy has led to hundreds of NSR enforcement actions and citizen suits targeting the very sort of projects that the Proposed Rule would now seek to require EGUs to undertake. EPA should eliminate the threat of protracted NSR litigation and provide a clear statement that any upgrades necessary to implement building block 1 for small entities would not trigger NSR.

While NSR presents a barrier for small entities to pursue heat rate improvement projects, the cost impacts and limited CO_2 benefits present their own set of challenges to meeting the Proposal's goals.

[12] 79 Fed. Reg. 34,859.

Small EGUs are key components of both public power and rural co-operative generating systems. Small units—historically are considered those less than 200 MW of capacity—are limited in their ability to install state-of-art heat rate-improving steps. Please see the discussion in the section VI Heat Rate Improvement Challenges, summarizing the results of a whitepaper on the heat rate improvement options for small, low capacity facts EGUs. The whitepaper quantifies the challenges of cost-effectively installing heat rate-improving steps in an attempt to meet the goals of building block 1.

B. Section 111(b) for Modified and Reconstructed Units

In numerous parts of the Modified/Reconstructed Proposed Rule, EPA suggests EGUs that become subject to a state or federal plan under section 111(d) and then undergo a modification or reconstruction must remain subject to the requirements of the state or federal plan, in addition to having to comply with the requirements for modified and reconstructed EGUs proposed here. See, e.g., 79 Fed. Reg. at 34,962-63, 34,965. Under the Clean Air Act, a source is either "existing" or it is "new." It cannot be both at the same time. Compare CAA § 111(a)(2)(definition of "new source") with CAA § 111(a)(6) (definition of "existing source"). Therefore, a source that is regulated under section 111(b), either because it is a "new source" or because it underwent a major modification or reconstruction and became subject to section 111(b), cannot simultaneously be subject to regulation under section 111(d) as an "existing source." If a state wishes to keep an EGU that is modified or reconstructed within its section 111(d) state plan, it may do so as a matter of state law. See *id*. § 116. EPA cannot, however, require states to keep that EGU within its section 111(d) state or federal plan.

VI. Heat Rate Improvement Challenges

APPA believes EPA has no statutory authority to define the "best system of emission reduction" (BSER) in a way that goes beyond technological or operational improvements that can be made at an individual source. We offer the following discussion of inside-the-fence-line heat rate improvement options to highlight the challenges facing small public power and rural co-operatives since they are least likely to be able to employ "outside-the-fence-line" measures, such as re-dispatch to other types of generation or requiring consumers to reduce their demand for electricity. The whitepaper, "*Heat Rate-Improving Options for Small, Low Capacity Factor Generating Units: Comparison of Capital, CO_2 Avoided, Payback" looks at* representative sample units owned by APPA and the National Rural Electric Cooperatives Association (NRECA) members, illustrating the challenges of installing heat rate-improving options using building block 1. The whitepaper's analysis determined higher capital cost project such as a steam turbine upgrade for a 500 MW name plate capacity unit will lower CO_2 by 40 lbs/MWh, and require three years to payback capital expenditures. For a 100 MW unit, 60 lbs/MWh of CO_2 is avoided, but the payback period is 12 years. A 12 year payback period is not sustainable by owners of small EGUs in the present power market. Lower capital cost options such as improved process controls and boiler cleaning have lower capital requirements – typically less than $600K for a 100 MW unit. The CO_2 avoided is 15 lbs/MWh and a seven year payback is required.[13] Despite the lower capital costs, these projects still require financing, another barrier to implementing heat rate improvements. Small public power utilities require regulatory relief in the form of additional timing and

[13] J. Edward Cichanowicz and Michael C, Hein*; "Heat Rate-Improving Options for Small, Low Capacity Factor Generating Units: Comparison of Capital, CO_2 Avoided, Payback", May 27,2015.*

or credits/ allowances least they be forced to shut down due to an inability to meeting prescribed goals under building block 1.

VII. Regulatory Flexibility Alternatives

Public power utilities offer the following thoughts and suggestions on alternative regulatory flexibility options. First, EPA has to determine the point of regulation. The Agency will either place the compliance obligation on the state or it will place the compliance obligation on the EGU.

A. Option 1: State Portfolio Approach to Federal Plan

Assuming EPA issues a final rule that applies a system-based Best System of Emissions Reduction (BSER) rather than an approach based on what can be achieved by affected sources, the Agency should propose an FP that preserves a state's portfolio options rather than a source-based approach. Taking this approach would be consistent with the approach taken in the underlying rule by placing the compliance obligation on the state subject to a federal plan. It would also retain all compliance options, including the measures contained in building blocks 1, 2, 3, and 4.

B. Option 2: EGU-Based Federal Plan

If EPA's proposed FP places the emission reduction obligations on an individual EGU, EPA must provide a mechanism to ensure EGUs have broad access to emission reductions outside the fence line, lest they be forced to shut down the unit as the only available compliance option. The emission reduction obligation should not be placed on load–serving entities.[14] The following are additional elements EPA should include in an EGU-based FP if it chooses to impose the obligation on EGUs:

1. Alternative Emission Reduction Credit and Credit Safety Valve

In addition to providing EGUs with "beyond-the-fence" compliance options under an FP, EPA should develop a robust interstate emission reduction credit (ERC) program that would enable EGUs to connect with the broader energy system and provide them with a reasonably priced compliance option. ERCs could be created from excess emissions reductions achieved through building blocks 1, 2, 3, and 4. Any credit or allowance system must also have a maximum price safety valve in order to allow investment in emissions reducing strategies while ensuring that operators are not discouraged from making upgrades and investments to their existing infrastructure.

Additionally, the FP should be designed to prevent third parties from acquiring and retiring credits or allowances.

[14] In the case of public power, load serving entities often do not own or operate generation equipment and are small distribution utilities with limited resources to obtain emission reductions.

2. Single and Small Asset Minimum Run Time

Small entities that own single coal-fired generation units are particularly at risk under an FP. EPA should give special consideration to these EGUs through the development of compliance options based on an annual "minimum run time" that would prevent stranded costs. This process must take in to consideration unit-by-unit criteria, such as utilization factors, age, remaining useful life, and feasibility of emission reduction measures.

3. Small Entity Exemption

Assuming small single EGUs are unable to purchase ERCs or benefit from reductions achieved through building blocks 1, 2, 3, and 4, these units should be exempt from meeting emission reduction goals in order to preserve their remaining useful life and prevent the loss of economic value.

4. Reliability Review and Dynamic Reliability Safety Valve

APPA supports the adoption of several mechanisms to assure grid reliability throughout the development and implementation of state and federal plans. These include an initial review of state and federal plans conducted by the North American Reliability Corporation (NERC), a reliability safety valve to address unforeseen circumstances, and periodic review by NERC of the state and federal plans on a regional basis.

5. Allow Full Credit for Early Actions and Innovative Efficiency Programs

Any FP EPA proposes should include some mechanism to provide credit for early action. Assuming a small entity can show verifiably that it has reduced its emissions via some measure, it should receive credit. Small entities have deployed a variety of energy efficiency programs utilizing deemed saving to reduce electricity consumption by promoting products or programs that support efficiency or conservation of electricity.

A FP should include a crediting mechanism to EGUs for improved city building codes, energy efficiency programs from the utility, beneficial steam use, and other innovative methods for optimizing the electric system, such as water heater demand response.
Beneficial electrification such as electric cars should receive credits as they will add load, but reduce overall criteria pollutants.

6. Flexibility through Allowance Allocation Methodology

Allow states to make allocation of allowance/credit decisions even after a FP. This is critical because the state will best understand local and regional reliability conditions. The state will also understand which entities are most able to afford certain compliance elements and be better able to consider the compliance cost as is a part of the section 111 (d) process.

7. Multi Year Averaging

The proposed FP should utilize multi-year averaging for compliance over at least a five year period. Multi-year averaging affords small entities important flexibility given the increasing climate variability. As recognized in EPA's NODA to the underlying Clean Power Plan,[15] variations in weather have a significant impact on not only the demand for electricity, but also the type of electricity generated in a given year. Averaging the baseline will tend to reduce the impact of weather anomalies as well as scheduled unit outages.

8. Mass vs. Rate Compliance Mechanisms

The SBAR panel presentation materials suggested EPA is evaluating both a massed based and a rate based compliance approach. APPA supports allowing small entities subject to a FP the ability to choose a rate or mass based compliance pathway most appropriate to their geographic location and generation mix.

If a mass-based program is selected, EPA should reduce the burden of small communities by providing allowance mitigation for small public power utilities on behalf of their communities in the form of free credits. Utilities (or their communities) would have flexibility to determine how the credit value associated with the sale of the free credit is utilized, although its intent would be to reduce the financial burdens of investing in a cleaner resource portfolio.

9. Interstate Impacts

The proposed FP needs to take into consideration the complex circumstances in which public power utilities operate. Many small entities have generating assets located in one state and allowances/credits may be earned in another state where there is no state-to-state agreement. For example, a city owns land and builds community solar in its home state for compliance with a FP emission rate in another state. In this scenario, cities are looking at much larger compliance costs, or the possibility of having no compliance option, despite their investment.

10. Remaining Useful Life Impacts on Rate and Economic Losses

Compliance with the emission goals contained in the Proposed Rule will cause the retirement of a significant number of U.S. coal-fired generating plants. In particular small entities are especially vulnerable. If these facilities are retired while they are still able to yield on-going economic value, their retirement will impose an economic cost on the owner-generator and, in turn, its customers. APPA believes a proposed FP must account for the remaining useful life of a unit to provide a backstop against stranding assets.

Clearly, source-level emissions standards are likely to translate into reduced run times and lower electric production from coal-fired electric generators. In most cases, this will lead to economic

---

[15] http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents#NODA and http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-translation-state-specific-ratebased-co2

losses in the form of higher electric rates for consumers or uncompensated costs for utilities, or both. The following analysis depicts the potential losses for a hypothetical, but representative, utility and its retail customers.

The analysis shows the situation for an illustrative small utility that relies primarily on a single (100 MW), self-owned, coal-fired-generator to serve its retail load.[16] Based on assumed values for key inputs, including initial capital cost, fixed operation and maintenance (O&M), debt service, fuel, variable O&M and average capacity factor, the annual cost of service (or revenue requirement), the present value life-cycle cost of service and the leveleized electric rate necessary to recoup the present value (PV) cost of service, are all calculated. The economic impacts at several different levels of assumed lost production are measured by comparing the results of these cases to a reference case depicting costs and rates prior to the output reductions.

The underlying notion is that utility rates are designed to recover the utility's cost of providing service, which will be equal to the sum of the costs associated with individual assets and expense items. A generating asset has both fixed and variable costs and when production levels change, both total cost, and the average cost upon which rates are based, change as well. When production declines, variable costs fall but fixed costs do not, therefore average costs rise. Average costs will also rise if the lost output is replaced by higher cost resources. If rates remain unchanged when average cost rise, revenues will be insufficient to recover total costs and the utility will suffer an economic loss. If rates rise commensurate with increasing average costs, customers will suffer a loss in terms of higher total payments for any given level of electricity consumption or the unit will be forced to shut down

Several factors can affect the outcomes, but the tables below focus on the varying impacts associated with two crucial variables, the magnitude of production losses, and remaining useful asset life, while holding other factors constant. Because it is unlikely that a utility with an obligation to serve load would fail to replace lost production, [17] the outcomes reflect the assumption that lost coal output is replaced with some combination of other resources costing 25 percent more than the forgone coal production.[18]

Table 3 below shows the economic losses borne by the utility if rates do not adjust when output declines. Table 4 shows the impact on customers, in terms of percent change in leveleized rates, when rates do adjust in order to make the utility whole. Both tables have the same layout. The rows show differing assumptions regarding remaining useful life, and the columns show different assumptions regarding percentage reductions in output. For example, referring to Table 3, a 10 percent reduction in output for a plant with 20 years of remaining useful life, will lead to a present value economic loss to the utility of approximately $6.8 million if rates don't adjust.

[16] It would be rare to find a utility that relies exclusively on a single generator to meet all its energy requirements, so in most cases, it might be more meaningful to frame the analysis in terms of stand-alone impacts on generators, which will have incremental impacts on a utility's overall supply portfolio costs.

[17] It is conceivable that a utility with excess generation might simply forgo market sales, but this would translate into losses for the utility or higher consumer costs, through loss of the associated a cost of service credit. It is also conceivable that the lost output could be made with energy efficiency programs, but average rates would rise and one would have to calculate the total costs of providing the energy services with energy efficiency program costs and higher rates.

[18] This factor represents a reasonable approximation of the ratio of all-in costs of a replacement gas unit to the variable operating costs of a coal plant. The factor could be higher or lower depending on the assumed replacement portfolio.

As shown on Table 4, the same scenario would lead to an increase in leveleized rates of about 1.4 percent if rates do adjust. Overall, based on the scenarios depicted, the tables show a range in potential economic losses to the utility from about $4 million to about $45 million, and a range of possible rate increases from about 1.4 to approximately 7.4 percent.

Table 2 Economic Losses Based on Decline in Output

	Output Reduction	Output Reduction	Output Reduction
Remaining Life	10.00%	20.00%	50.00%
	Thousands $$$	Thousands$$$	Thousands $$$
30	$8,989	$17,978	$44,945
20	$6,784	$13,567	$33,919
10	$3,978	$7,955	$19,888

Table 3 Electric Rate Adjustments As Output Declines

	Output Reduction	Output Reduction	Output Reduction
Remaining Life	10.00%	20.00%	50.00%
	% Increase	% Increase	% Increase
30	1.24%	2.48%	6.20%
20	1.35%	2.70%	6.74%
10	1.48%	2.95%	7.38%

This analysis provides an indicative range of values for the economic losses that might be incurred by a utility with characteristic similar to the hypothetical example, if new GHG emissions standards lead to shorter run times and lower power plant production. The results are illustrative, and intended to give a quantitative sense of the issue, as opposed to providing firm estimates of potential outcomes. However, we do believe that new emission standards could lead to significant economic losses for utilities and/or electricity consumers, and that this should be explicitly taken into account when new emission standards are being considered.

VIII. Overarching Regulatory Flexibility Need in the Proposed Clean Power Plan

A. Interim Goals

APPA supports a relaxation of the interim goals, they do not support an orderly transition for small entities seeking to utilize or develop low carbon intensity technologies. The Proposed Rule states that its interim goals, which must be achieved on average over 2020 to 2029, and its final goals, which must be achieved by 2030, provide states with flexibility to design plans over the long term. But because the interim goals are so stringent, many states will have to take significant actions by 2020 in order to comply. The Proposed Rule also requires significant effort by the states in preparing their plans, including the requirement to include achievement "demonstrations" that use utility-scale capacity expansion and dispatch planning models to show the state can meet the interim and final goals. This requirement exceeds the statutory standard that a state plan be "satisfactory." Moreover, if EPA is going to require this type of effort from the states to develop the plans, then the Agency must give far more time to the states than the Proposal contemplates.

B. Emission Baseline

Any state or federal plan should provide small entities with the flexibility to use the highest three out of the past five years for baseline determination for a unit. For plants that were not online in the baseline case, should be the average of the three highest years for which the plant is fully online. Therefore, instead of prescribing 2012 as the baseline, the final rule should allow each state to establish a baseline the state believes equitably represents its circumstances, utility generation, and related emissions. Variations of this approach are obviously available as well. The key element is to provide some flexibility so that the final emission goal is equitable.

IX. Conclusion

APPA appreciates opportunity to share our overarching concerns about the Proposed Rule and comment on the small entity regulatory flexibility alternatives we believe EPA should consider as the Agency drafts the Federal Plan for Regulating Greenhouse Gas Emissions from EGUs. We strongly recommend the FP include:

- A mechanism to account for a small entities remaining useful life as prescribed in the statue.
- Exclude Reciprocating Internal Combustion Engines (RICE) and Simple Cycle Natural Gas (SCNG) Units.
- Reduce reporting obligations for EGUs with a nameplate capacity of less than 100MW.
- A clear statement that any upgrades necessary to implement building block 1 for small entities does not trigger NSR.
- A clarifying statement that new units are not subject to section 111(d)

- Provisions to ensure EGUs have broad access to emission reductions outside the fence line, lest they be forced to shut down the unit as the only available compliance option.
- A robust interstate ERC program that would enable EGUs to connect with the broader energy system ensuring reasonable access to credits.
- A compliance option based on an annual "minimum run time" that would prevent stranded costs.
- A provision for small entities unable to purchase ERCs or benefit from reductions achieved through building blocks 1, 2, 3, and 4, these units should be exempt.
- A reliability review by FERC and NERC and inclusion of a dynamic reliability safety valve.
- Full credit for early actions and innovative efficiency programs
- Multi-year averaging for compliance over at least a five year period.
- Giving small entities the ability to choose a rate or mass based compliance pathway.
- Consideration for the multi-jurisdictional and regional circumstances in which small public power utilities operate.

Please contact Mr. Alex Hoffman (ahoffman@publicpower.org) or Ms. Carolyn Slaughter (cslaughter@publicpower.org) if you have questions regarding APPA's comments on regulatory flexibility for small entities under EPA's Federal Plan for Regulating Greenhouse Gas Emissions from EGUs.

Sincerely,

Carolyn Slaughter
Director, Environmental Policy
American Public Power Association
Email: cslaughter@publicpower.org

APPENDIX 1

HEAT RATE-IMPROVING OPTIONS FOR SMALL, LOW CAPACITY FACTOR GENERATING UNITS: COMPARISON OF CAPITAL, CO_2 AVOIDED, AND PAYBACK

Prepared for the

American Public Power Association

And the

National Rural Electric Cooperative

Prepared by

J. Edward Cichanowicz
Saratoga, CA

and

Michael C. Hein
Whitefish, MT

May 27, 2015

I. Table of Contents

LIST OF FIGURES

LIST OF TABLES

II. SECTION 1

INTRODUCTION AND SUMMARY

Electric generating units (EGU) of "small" output capacity will encounter barriers to meeting the carbon dioxide (CO_2) reduction targets used as the basis of Building Block 1 of the proposed Clean Power Plan. Small generating units, typically considered those of less than 200 MW capacity, cannot economically derive the same benefits in heat rate and CO_2 reduction as the larger units that comprise the bulk of the U.S. coal-fired fleet.

Many small units are owned by public power utilities or rural cooperatives and qualify as small entities, as defined by the Regulatory Flexibility Act (RFA) and amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA). Small entities can face limits in raising capital due to the control procedures required for expending public funds.

Municipal utilities raise capital for many of their environmental projects by issuing bonds, which are rated by three major agencies: Moody's, Standards & Poor and Fitch. A bond rating does not constitute a recommendation to invest in a bond and does not take into consideration the risk preference of the investor. While many factors go into the investment decision-making process, the bond rating is often the single most important factor affecting the interest cost on bonds. Moody's has developed a municipal utility scorecard[19] that outlines the rating factors taken into consideration by the agency; these include the system characteristics, financial strength, and various management and legal provisions.

These rating factors are particularly important for small entities as they can dictate decisions about replacing, repairing or modifying aging equipment, all while delivering adequate service with existing resources. Regulatory compliance and capital planning are also factors that rating agencies consider; specifically how well a utility complies with relevant regulations and their plans for capital expenditure to comply with future mandates. Small public power utilities and rural cooperatives are less likely to have generation redundancies, which allow a system to shut down some of its operation in an emergency or to make repairs without interrupting service. Any capital needed is likely to be more costly relative to the limited annual budget of small entities, while evaluating and deploying heat rate improvements will be hampered by limited engineering staff.

This paper explores the barriers that public power or cooperative owners of small units could encounter in deploying heat rate improvements in an attempt to meet the proposed Building Block 1 CO_2 reduction goals. The results of this analysis quantify the capital

[19] Dan Seymour and Brady Olsen, *US Municipal Utility Revenue Debt,* Moody's, July 30, 2014.

requirement and the "payback" time to recoup the investment for heat rate improvements. Several examples of heat rate-improving options are selected to evaluate the benefit of avoided CO_2 emissions in addition to capital required and the payback time. For this analysis, an investment of $750K is selected as an arbitrary threshold defining "higher" or "lower" cost investments. Thus, options considered in this analysis reflect investments of both "lower" cost – those requiring less than $750K – and of "higher" cost, requiring greater than $750K.

The capital requirement, CO_2 avoided, and the payback for several heat rate-improving options is calculated for two reference units, reflecting "small" and "conventional" generating capacity. A reference unit of 100 MW capacity is selected to reflect small units, representing the 25-200 MW range. A reference unit of 500 MW capacity is selected to represent "conventional" units. The capital cost for and the benefits of various heat rate options were obtained from analysis conducted for the Utility Air Regulatory Group (UARG)[20] and from the 2014 National Coal Council report to the Department of Energy Secretary.[21] The reduction in operating cost and the payback time is determined using heat rate benefits and capacity factors appropriate for each unit; the latter 45% and 75% for the 100 MW and 500 MW units, respectively. The delivered fuel price is the same ($2.25/MBtu) for both units.

The results show owners of small generating units will incur a payback period for heat rate-improving options that significantly exceeds that for owners of conventional (e.g., 500 MW) units. Most notably, the payback period for a steam turbine upgrade to a 500 MW unit is shown to be 3-4 years, based on a 200 Btu/kWh reduction in heat rate. In contrast, owners of small generating units – even if assumed to extract a greater heat rate benefit of 250 Btu/kWh – incur an almost 12-year payback period. This extended payback time, given present environmental mandates and the wholesale power market, presents significant risk to owners that a unit will remain a viable generating option. Further, the absolute value of capital required – likely exceeding several million dollars for an installed system – could be a challenge to acquire for small public power entities.

Section 2 describes the approach used in this analysis, and Section 3 the key operating characteristics of small generating units that dictate results. Section 4 summarizes the heat rate-improving options considered in this analysis, and Section 5 presents the results. Conclusions are offered in Section 6.

---

[20] *Evaluation of Heat Rate Improving Techniques for Coal-Fired Utility Boilers as a Response to Section 111(d) Mandates*, Prepared for UARG by J.E. Cichanowicz and M.C. Hein, October 13, 2014. Hereafter UARG 2014 Heat Rate Report.

[21] National Coal Council 2014 Report to the Secretary of Energy, *Reliable and Resilient: The Value of Our Existing Coal Fleet*, May 2014. Hereafter National Coal Council 2014 Report.

III. SECTION 2

APPROACH

This analysis employs three elements: (a) quantifying the capacity factor and CO_2 emission rate (lbs MWh, net basis) for small generating units; (b) selecting several "reference" units and heat rate-improving options that could be deployed to small and conventional units, and (c) quantifying the results in terms of capital required, CO_2 avoided, and the payback period.

First, quantifying the capacity factor and CO_2 emission rate of small units that are owned by public power and rural cooperative entities is necessary to distinguish between the operation of small and conventional generating units. This paper focuses on owners that qualify as small businesses, although data from small units owned by a variety of entities is used to strengthen the analysis. Small unit data is compared to analogous data describing the operation of conventional, larger units.

Second, examples of heat rate improvements potentially available to use in an attempt to meet Building Block 1 goals of the Clean Power Plan are selected, based on 2014 reports issued by UARG and the National Coal Council. Heat rate-improving options qualifying as "lower" cost (e.g., less than $750K capital) and "higher" cost (greater than $750K capital) are both considered. The $750K threshold represents an arbitrary but rationale means to delineate heat rate-improving options, which range in cost from several hundred thousand dollars to $7M, depending on unit output.

Third, we define two reference units as examples to quantify the results for a limited number of heat rate-improving options. As noted, capital investment, avoided CO_2 emission rate, and "payback" period to recover that investment are determined.

Details and results are presented in subsequent sections.

IV. SECTION 3

OPERATING CHARACTERISTICS OF SMALL ELECTRIC GENERATING UNITS

Section 3 describes the operating characteristics of small generating units that determine the benefit and cost recovery for heat rate reduction options. This discussion is preceded by a description of the generating units selected for analysis.

A. Reference Units

Reference units are drawn mostly from APPA and NRECA portfolios, focusing on small units operated by owners considered by the Environmental Protection Agency (EPA) to be small business entities.

Table 3-1 summarizes the units used to establish trends in capacity factor and CO_2 emission rate based on the last 7 years of operation. Not all generating units in Table 3-1 are owned by entities designated as small businesses (e.g., Tri-State G&T) but these are included to broaden the database.

Seventeen of the units in Table 3-1 are owned by members of NRECA while five are owned by members of APPA.

B. Small EGU Capacity Factor, CO_2 Emission Rate

The capacity factor and heat rate for the small generating units in Table 3-1 are presented in Figures 3-1 and 3-2.

Figure 3-1 describes the average capacity factor, distinguishing between NRECA and APPA owners, based on generation data submitted to the Energy Information Agency (EIA). The data presented Figure 3-1 show an almost year-by-year decrease (with the exception of 2010) in capacity factor from 2007 through 2013. There is little difference in the capacity factor of NRECA and APPA–member units over this time period; capacity factor in four of the seven years is almost identical. Notably, in 2013 the small unit capacity factor is approximately 15 percentage points less than the average generating unit in the national coal-fired inventory.

Figure 3-2 shows the CO_2 emission rate (lbs/MWh, net basis) increases over the same period of 2007 through 2013. It is well known that operating at lower load compromises heat rate and elevates the CO_2 emission rate. Two examples showing the increase in gross plant heat rate at lower load are presented in Appendix A, representing APPA and NRECA owners. The trend in higher CO_2 emission rates is likely influenced by, among other factors, the decrease in capacity factor since 2007.

Table 3-1. Small Units Owned by APPA/NRECA Members

State	Owner/Operator	Station/Units	Capacity (MW, net)
MI	City of Grand Haven (MI)	JB Sims Unit 3	65
OH	City of Orrville (OH)	Orrville	63
CO	City of Colorado Springs (CO)	Drake Unit 6	75
MI	City of Lansing (MI)	Eckert Units 4-6	80
AL	Power South (Alabama Electric Coop)	CR Lowman Unit 1	80
Various	Tri-State G & T	Nucla Unit 4	64
IA	City of Corn Belt (IA)	Earl F Wisdom Unit 1	38
IA	Central Iowa Power Coop	FE Fair Unit 2	41
KY	Big Rivers Cooperative	Reid Unit 1	65
	E. Kentucky Power Coop	Dale Units 1/2/3/4	27/27/81/81
		JS Cooper Unit 1	114
MO	Central Electric Power Coop	Chamois Unit 2	44
WI	Dairyland Power Coop	Alma Units 4/5	55, 82
IN	Hoosier Electric Coop	Ratts Units 1/2	117/117
IL	S. Ill Power Cooperative	Marion Unit 4	173
		New Marion	99

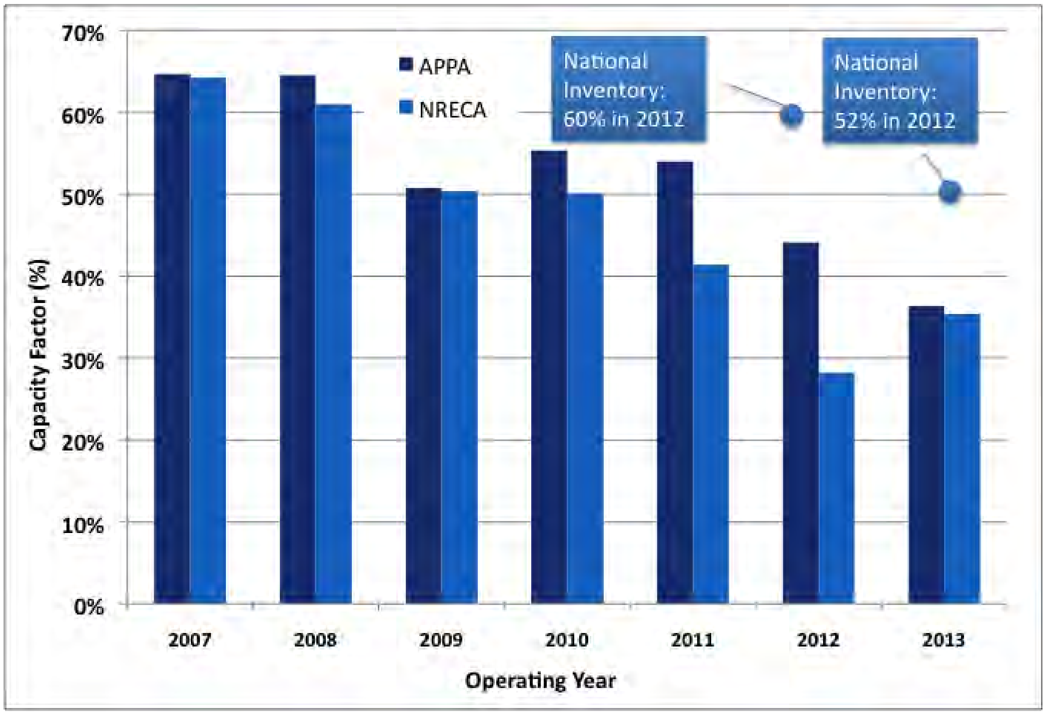


Figure 3-1. Capacity Factor for Small APPA/NRECA EGUs, 2007- 2013

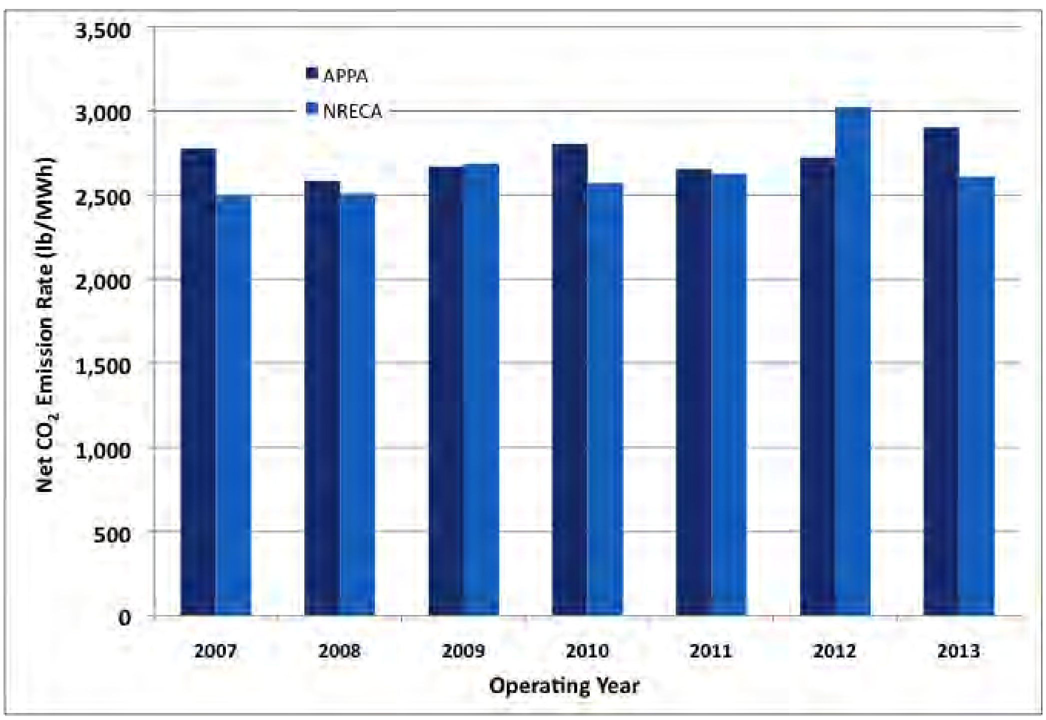


Figure 3-2. CO_2 Emission Rate (Net) for Small APPA/NRECA EGUs, 2007- 2013

C. Comparison to Conventional Inventory

The uniqueness of small generating units compared to conventional, larger coal-fired units is demonstrated by comparing the capacity factor and CO_2 emissions from these groups, as revealed in Figures 3-3 to 3-6.

Figure 3-3 shows CO_2 emission rates from small units exceed those of conventional, larger units. Units of higher generating capacity can deploy heat rate-improving concepts that may not be economically feasible or even applicable to small units. Figure 3-4 shows the higher CO_2 emission rate of small units is not solely due to unit age. Higher CO_2 emissions are observed not only for units with greatest longevity – those in service for at least 40 years – but also for units with service of 20-40 years. Even a relatively "new" unit – in service for less than 10 years – will emit more CO_2 than newer units in the national inventory, due to either a low capacity factor or constrained design options.

Figure 3-5 provides further insight to the role of capacity factor. This depiction presents data for three of the four quartiles of capacity factor data describing both small and conventional units. The results show higher CO_2 emissions are generated from small generating units. Figure 3-5 demonstrates capacity factor alone is not responsible for the higher CO_2 emission rate.

Finally, regardless of coal source – bituminous, subbituminous, or a blend of these – higher CO_2 emissions are incurred with small generating units (Figure 3-6).

D. Small Unit Operating Characteristics:

The observations based on data presented in Section 3 are summarized as follows:

- The capacity factor of small EGUs has almost continually decreased each year since 2003. For the year 2013, capacity factor is 15 percentage points less than the capacity factor of an average unit in the national coal-fired fleet.

- Over the same period of time, the CO_2 emission rate (lbs/MWh, net basis) has increased, and exceeds by 25% the CO_2 emission rate of the average unit in the national coal-fired fleet.

- The higher observed CO_2 emission rate of small units compared to the national fleet is observed for units of all ages, ranging from those with less than 10 years to those with more than 40 years of service, and is independent of coal rank.

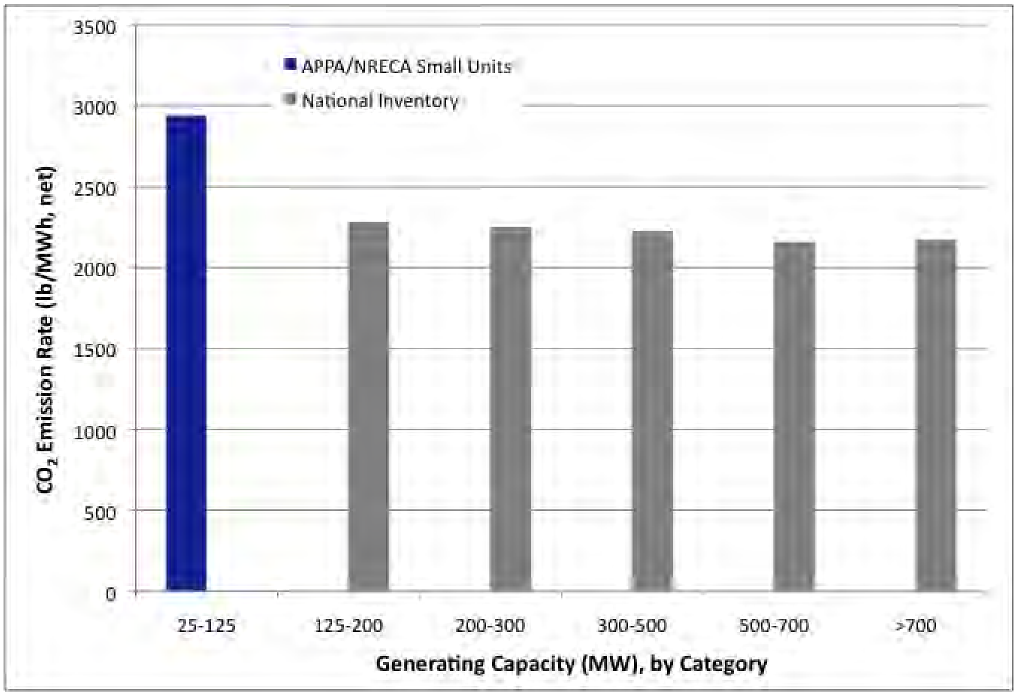


Figure 3-3. CO_2 Emission Rates by Categories of Generating Capacity (MW): Small APPA/NRECA EGUs, 2007 - 2013

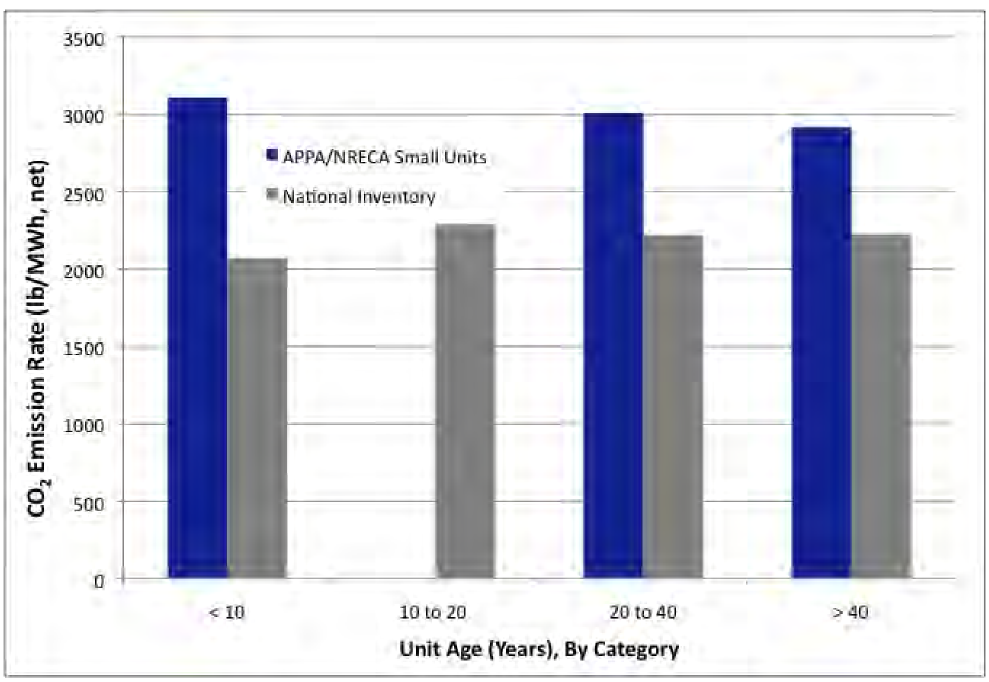


Figure 3-4. CO_2 Emission Rates by Category of Unit Age (Years): Small APPA/NRECA EGUs, 2007 - 2013

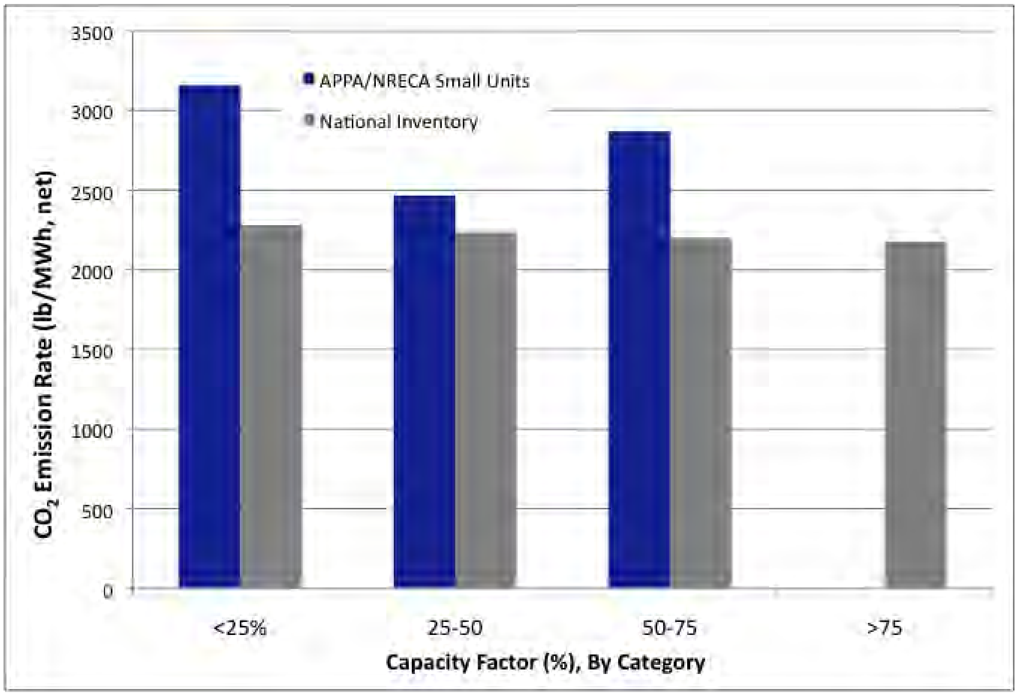


Figure 3-5. CO_2 Emission Rates for Small EGUs vs. National Inventory, By Quartiles of Capacity Factor

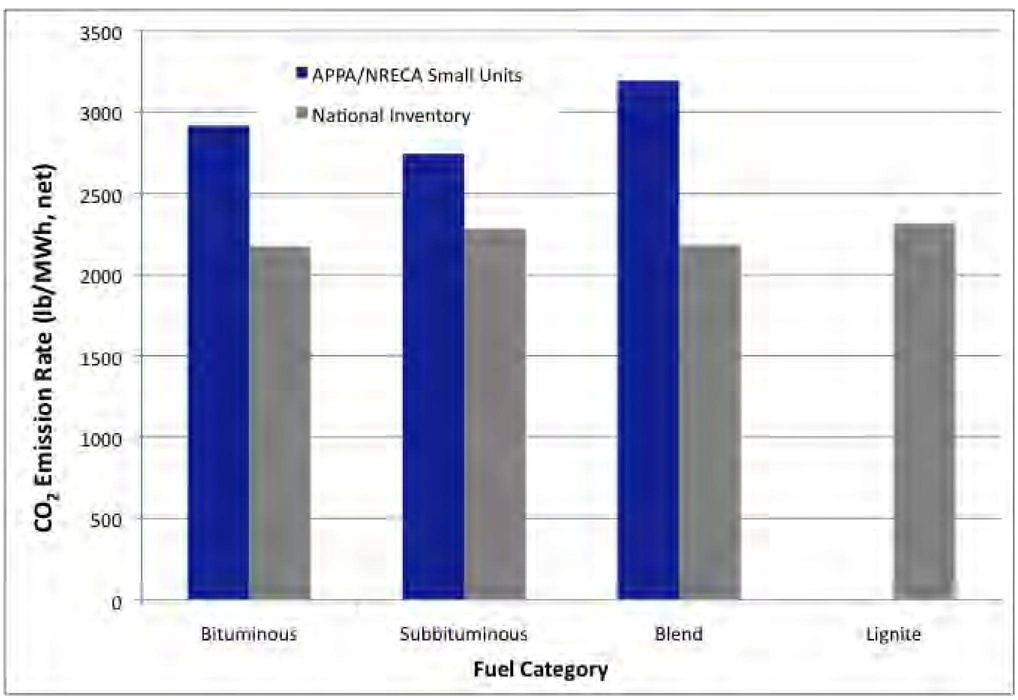


Figure 3-6. CO_2 Emission Rates for Small EGUs vs. National Inventory, By Coal Rank

V. SECTION 4

EVALUATION OF HEAT RATE-IMPROVING OPTIONS

Section 4 describes example heat rate-improving options for small generating units, and the basis for calculating how these options affect unit operation.

A. Heat Rate Improving Options

The options for improving coal-fired plant heat rate have been summarized in two recent reports – one prepared for the UARG for submission to the EPA as part of comments for Section 111 (d) rulemaking,[22] and a second report prepared by the National Coal Council in 2014 recommending research and development actions to the Secretary of Energy.[23] A detailed treatment of heat rate-improving options is beyond the scope of this paper; further discussion is referenced to these reports. This section summarizes examples of heat rate-improving options that are available and selects several for evaluation for a reference small and conventional EGU.

Table 4-1 summarizes heat rate-improving actions derived from the UARG and National Coal Council reports. The options are delineated according to the threshold of $750K as defining “higher” and “lower” cost.

The higher cost options in Table 4-1 could require capital for a 500 MW unit from $1 M (boiler surface changes) to $6 M (steam turbine upgrade), providing heat rate savings from 50 to 225 Btu/kWh. The lower cost options all require capital less than $750,000 and could deliver benefits of 20 to 100 Btu/kWh.

Three of the heat rate-improving options in Table 4-1 are selected to evaluate their impact on the two “reference” unit defined. These options are evaluated in terms of (a) capital requirement, in terms of both total expenditure (i.e., $M of dollars) and normalized to generating output ($/kW), and (b) investment payoff in heat rate and CO_2 reduction.

[22] UARG 2014 Heat Rate Report.
[23] National Coal Council 2014 Report.

Table 4-1. Heat Rate Improving Options

Heat Rate-Improving Option	Description
Higher Cost	
Steam turbine upgrade	Improve steam path with changes to either or several of the high-pressure, intermediate-pressure, or low-pressure expansion sections. Requires replacement of steam turbine blades and components.
Condenser replacement	Improve heat rejection to the cooling media – be it once-through cooling or to a cooling tower – by rebuilding or replacing the condenser. Typically condensers are located near the cooling source, and are difficult to access in a typical plant layout. Labor costs can be significant.
Addition to boiler surface area	In concept, the heat removing surfaces in a boiler can be augmented; the original design specifications may not be valid in the present environment or with the present fuel. Labor costs could be significant.
Cooling tower upgrade	The media within a cooling tower that promotes heat rejection – the so-called "pack" material – can be exchanged and in some tower designs improve the heat rejection.
Lower Cost	
Process controls	Improved process controls, most notably neural network software, continually seek the "optimal" plant actions. Requires an existing digital control system.
Improved boiler cleaning	The removal of deposits from boiler heat transfer surfaces by either more aggressive sootblowing or water cannons elevate boiler performance and increases boiler thermal efficiency.
Variables Frequency Drives	Minimizes auxiliary power consumption of ancillary equipment.

One higher cost and two lower cost heat rate-improving options are selected for analysis. The higher cost option selected is improving the steam path with a steam turbine upgrade. This option is broadly applied to conventional, large generating units and benefits from significant technical advances in the last decade.

The lower cost options are improved boiler cleaning and advanced process controls. Improved, on-line cleaning of boiler heat transfer surfaces is achieved by use of aggressive or intelligent automated cleaning devices, such as "smart" sootblowers or water cannons. Advanced process controls typically employ neural networks or other advanced software that continually seek the best combination of boiler operating variables to achieve the lowest net plant heat rate. Both of these options should require less than $750K for either a large or small generating unit. Neither option requires extensive hardware, assuming the unit is equipped with a digital control system; consequently the economies of scale are negligible (e.g. the cost is similar for either a small or large generating unit).

Both options impose a small fixed operating cost that is considered in the payback analysis.

B. Reference Generating Unit Evaluation

Two reference generating units are selected to quantify the benefit of the heat rate-improving options and define the barriers to implementation. The benefit is the reduction in operating cost and the associated avoided CO_2 emissions, the latter expressed in terms of lbs/MWh (net) basis. The barrier to implementation is cost in terms of both capital required (i.e., $M) and per output of power ($/kW).

Table 4-2 summarizes the capital cost and payoff in terms of heat rate improvement that is assumed for the three heat rate-improving options, as applied to the two reference units. The capital costs are derived from the UARG and National Coal Council reports, both of which document capital requirement for units of nominally 500 MW.

Table 4-2. Capital Required and Payoff of Heat Rate Improving Options

Option	Conventional (500 MW) EGU	Small (100 MW) Unit
Steam Turbine Upgrade		
- Capital ($M)	5	2.2
- Heat Rate Reduction (Btu/kWh)	200	250
Advanced Controls		
- Capital ($M)	0.6	0.4
- Heat Rate Reduction (Btu/kWh)	50	75
Advanced Boiler Cleaning		
- Capital ($M)	0.5	0.25
- Heat Rate Reduction (Btu/kWh)	60	80

Capital costs for applying heat rate-improving options to the 100 MW units are not explicitly reported in the literature; consequently, these costs are derived by scaling costs from the 500 MW to the 100 MW capacity. These estimates are derived using a conventional power-law scaling relationship as described in EPRI's Technical Assessment Guide.[24] It should be noted that scaling capital cost over a factor-of-five range is uncertain; consequently costs cited for the 100 MW unit should be considered approximate.

Table 4-3 summaries the assumptions required to determine the payback of each heat rate investment. Specifically, the conventional 500 MW unit is assumed to operate at 75% capacity factor, approximating their historical average. The 100 MW unit is assumed to operate at 45% capacity factor. The baseline heat rates are shown, as is the delivered fuel price – the latter selected based on EIA's projected delivered fuel price for 2015.

The capital cost normalized to output, CO_2 avoided, and payback period are quantified and presented in Section 5.

Table 4-3. Characteristics of Reference EGUs

Unit Feature	"Small" Generating Unit	"Large" Generating Unit
Capacity (MW)	100	500
Capacity Factor (%)	45	75
Baseline Heat Rate, Net (Btu/kWh)	11,000	9,500
Delivered Coal Price ($/MBtu)	2.25	2.25

[24] TAG Technical Assessment Guide, Electricity Supply – 1993, EPRI TR-102275-V1R7, Volume 1: Rev. 7, June 1993. See Section 8.3.7. "Capital Cost Adjustment – Size and Scale-Up, page 8-11.

VI. SECTION 5

RESULTS OF THE ANALYSIS

The results of this analysis clarify the challenges faced by owners of small units in deploying heat rate-improving options. This is demonstrated by considering the payback period over which capital is returned, which in addition to capital required is a key financial metric.

In the context of this analysis, the "payback" period is the number of years over which lower operating cost due to fuel savings returns the capital investment. The payback period is determined without considering the cost of financing the capital equipment, or the levelization of operating cost over future years. A strict determination of "payback" period would entail accounting for these cost-of-money factors; these are ignored in this approximate analysis.

A. Normalized Capital Per Payback Period

Figure 5-1 presents the payback period anticipated for investments associated with the three heat rate-improving options for the two reference units. Figure 5-1 shows the capital investment – in this depiction cast in terms of cost per output capacity ($/kW) – for the three options, presented versus the payback period. Figure 5-1 shows the larger generating capacity and higher capacity factor of the 500 MW unit minimizes the payback period – about 4 years for the highest cost option (steam turbine upgrade).

In contrast, the 100 MW unit – although requiring less capital on an absolute basis (i.e., $M of dollars) – is penalized as capital required per generator output is very high. For the steam turbine upgrade, the payback period is almost 12 years - exceeding the payback for the 500 MW unit by a factor of 3. The lower cost options of advanced process controls and deep boiler cleaning feature significantly shorter payback periods – 1-2 years for the 500 MW unit. For the 100 MW unit the extended payback period is 6-7 years.

B. CO_2 Reduction vs. Payback Period

Figure 5-2 presents the CO_2 reduction anticipated versus the payback period.

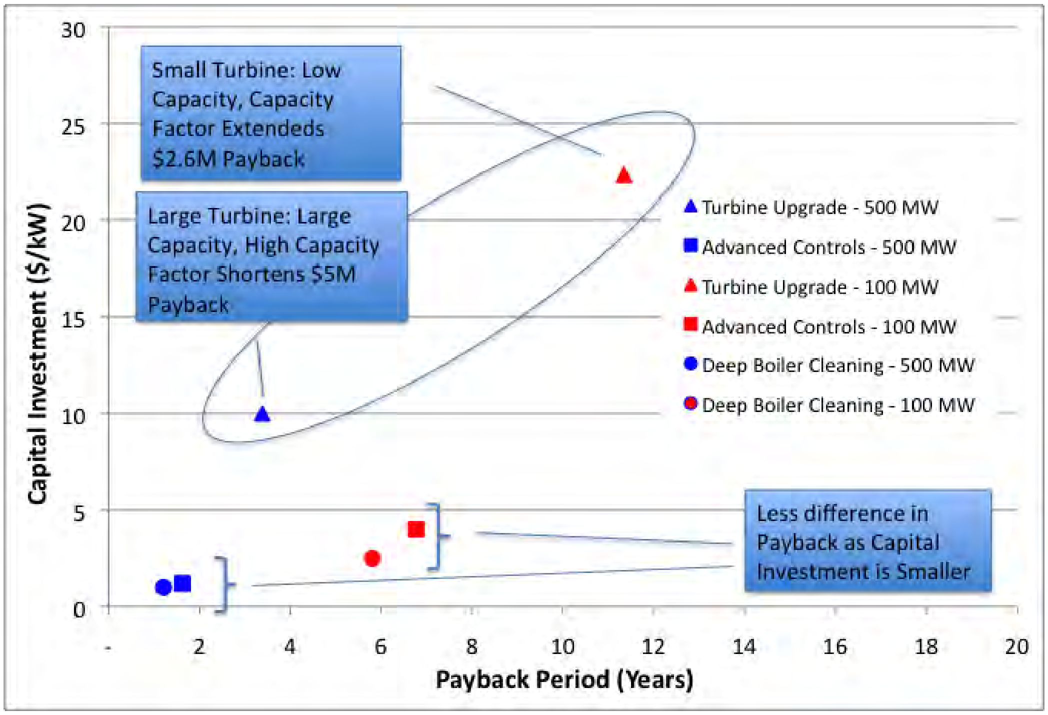


Figure 5-1. Normalized Capital Investment vs. Payback Period

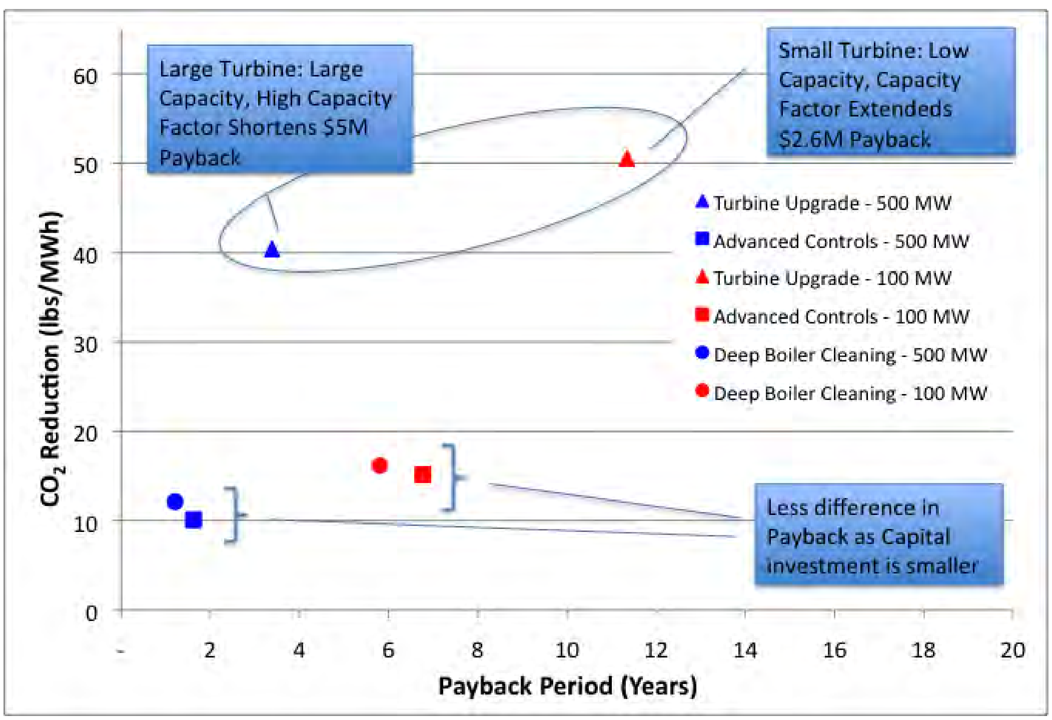


Figure 5-2. CO_2 Reduction vs. Calculated Payback Period

Figure 5-2 shows that a CO_2 emission rate of 10 and 50 lbs/MWh net can be avoided, depending on the heat rate improving option and the reference unit. The highest value of CO_2 avoided – up to 50 lbs/MWh for a steam turbine upgrade for the 100 MW unit – requires almost a 12-year payback. The smallest values of CO_2 avoided (10-12 lbs/MWh) require less than 2 years payback.

C. Results: Key Observations

The results show owners of small generating units, in executing the first steps in an attempt to address the proposed Clean Power Plan, will incur:

- Capital cost ranging from $500-700K and up to more than $2M, depending on the option
- Normalized capital cost from $3/kW to approaching $25/kW, depending on the heat rate–improving option
- Reductions in CO_2 emissions from 10-50 lbs/MWh net, as calculated based on generating capacity
- An extended "payback" period over which the capital investment is returned, due to lower fuel cost, requiring almost 12 years depending on the heat rate-improving option and the reference unit.

These consequences are not the complete impact of meeting the Clean Power Plan, but simply the first steps to attempt to meet the proposed assumptions used as the basis for Building Block 1.

VII. SECTION 6

CONCLUSIONS

Owners and operators of generating units that are either public power utilities or cooperatives can encounter barriers to raising capital, compared to investor-owners of larger units. As a result, public power and cooperative owners are limited in deploying the full suite of heat rate-reducing options. For many such owners higher capital cost options are excluded as they cannot be readily financed.

Small generating units – typically recognized as those with less than 200 MW but in this analysis focusing on units ranging from 44 to 177 MW – are evaluated. Most notable is the extended payback periods for heat rate investments to take the first steps to meet the proposed CO_2 emissions reductions assumed for the Clean Power Plan's Building Block 1. The limited generating capacity and lower capacity factor typical of small units are key determinates of the payback period. These conditions create the possibility of small unit owners inheriting generating assets that become "stranded", should these units be forced to shut down prematurely. Payback periods for the higher capital cost options can exceed 10 years, which can compromise the competitiveness of the unit given present market conditions.

The CO_2 emission rate typical of small units – as measured in lbs/MWh (net) – is higher than the CO_2 emission rate of conventional units. There are numerous reasons for the higher CO_2 emission rate – the design of the boiler and steam turbine; lower capacity factor, and frequency of startup/shutdown events.

As a consequence of these barriers, public power and cooperative entities will be restricted to deploying mostly lower capital cost options, limiting CO_2 reductions.

Numerous observers and owners of typical coal-fired generators have stated EPA's 6% heat rate improvement assumptions is not technically feasible[25]; the limit to deploying heat rate-improving options to be encountered by public power and cooperative owners of small units further assures this goal as unrealistic.

[25] UARG 2014 Heat Rate Report.

VIII. APPENDIX A

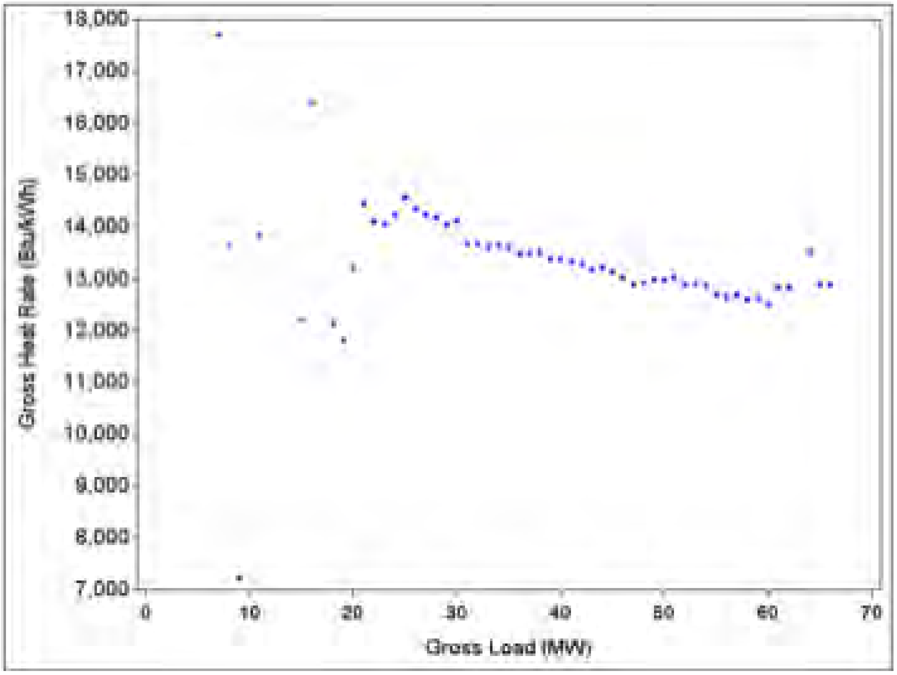


Figure A-1. Gross Plant Heat Rate vs. Load: CR Lowman Unit 1

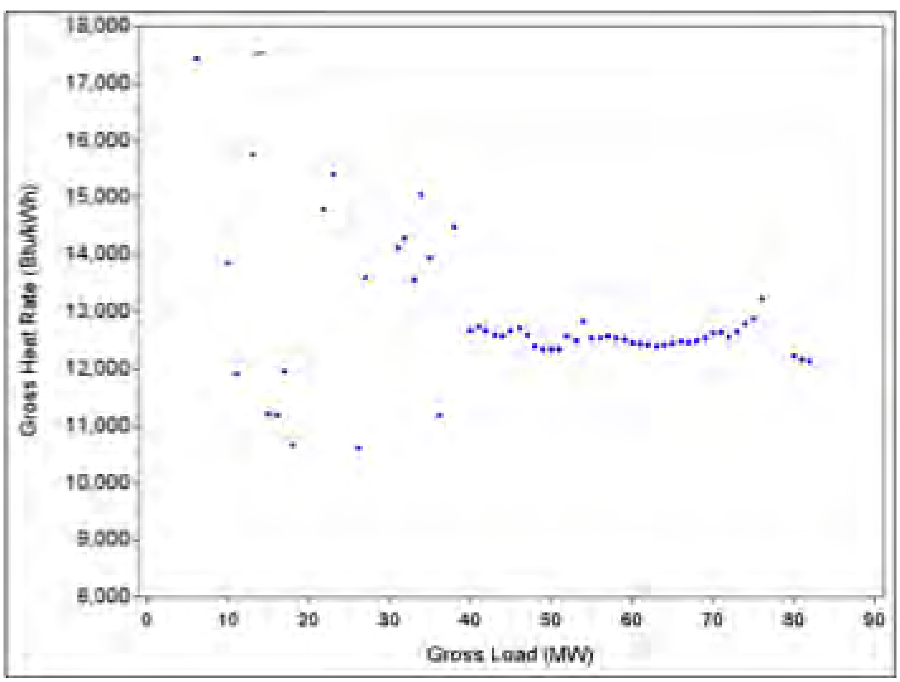


Figure A-2. Gross Plant Heat Rate vs. Load: Muscatine 8

Arizona Electric Power Cooperative, Inc.

Comments submitted to the

The Environmental Protection Agency Small Business Advocacy Review Panel

On

Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014

Submitted via Electronic Mail to:

Lanelle Wiggins
RFA/SBREFA Team Leader
US EPA – Office of Policy

May 28, 2015

Arizona Electric Power Cooperative, Inc. ("AEPCO"), which along with Southwest Transmission Cooperative and Sierra Southwest Cooperative Services, is one of three cooperatives making up Arizona's Generation and Transmission Cooperatives, is pleased to submit these comments. AEPCO also appreciates the opportunity to participate in the Small Business Advocacy Review panel as a Small Entity Representative. Additionally, we share the same concerns raised by the Small Business Administration's May 8, 2015 letter.

AEPCO is a rural, member-owned generation and transmission electric cooperative formed in 1961 to provide electric generation service to local rural, consumer-owned electric distribution cooperatives in Arizona. As a not-for-profit cooperative, AEPCO is fully owned by its members. AEPCO has six "Class A" members, who participate in and rely on AEPCO's electric generation services. Together, AEPCO's Class A members serve just under 150,000 meters, providing electricity primarily for residential use. Because of the rural and residential nature of the cooperatives it serves and which comprise its membership, AEPCO is a relatively small entity with limited financial means. AEPCO operates only one power generation facility: the Apache Generating Station ("Apache" or "AGS"). Collectively, Apache has approximately 555 MW of net installed capacity in its electric generating units ("EGUs"). Historically, over 80% of the energy AEPCO supplies is sourced from its very affordable coal units. The majority of the cooperatives' end-use electric customers are rural, and a substantial amount live at or below the federal poverty line, implying a high level of price sensitivity in electric rates.

The major units at Apache Station, coal-fired EGUs ST2 and ST3, were planned in the mid-1970s and installed by the late 1970s. At this time, the United States was undergoing multiple energy shocks due to the Oil Embargo and relatively limited supplies of domestically produced natural gas. In line with evolving United States energy policy favoring use of coal as a secure domestic energy source, AEPCO commissioned both ST2 and ST3 as coal-fired units, even though from a size perspective the units would have more typically been built as natural gas-fired units. AEPCO's decision to build coal-fired units was subsequently validated when Congress passed the Fuel Use Act, which forbid the use of natural gas for electric generation in new units to conserve natural gas availability for residential and commercial use.

Since that time, AEPCO's base load growth has not been sufficiently great to justify the installation of new, more efficient coal- or gas-fired load-following units. AEPCO thus remains heavily dependent upon its two coal-fired load-following units, ST2 and ST3.

SUMMARY OF CONCERNS

- The Clean Power Plan creates substantial risks to the reliability of Arizona's electric grid. These risks come from:
    - Closure of AEPCO's load-following coal-fired EGUs ST2 and ST3 that provide substantial capacity (350 MW out of 555 MW) and economic energy reliability to the southeast Arizona system.
    - Dislocation of the current electric transmission model, which is based on moving energy from the northern, eastern and southern periphery of the state toward Phoenix, Arizona. AEPCO is concerned that with the loss of ST2 and ST3, as may be required under the Proposed Rule, it will be unable to maintain voltage in the Southeast Arizona quadrant (the "southern bubble") that is currently anchored by Apache.
    - Inadequate time to provide for needed electric generation, transmission and natural gas transmission infrastructure upgrades.

- The Proposed Rule will result in severe economic stress on AEPCO, its members, ratepayers and ultimately the state economy.
    - The premature retirement of AEPCO's ST2 and ST3 will cost AEPCO upwards of $400 million to replace. The $400 million more than triples AEPCO's existing debt, thereby forcing rural and financially limited customers to pay for unused electric service.
    - ST2 and ST3 currently represent approximately 75% of AEPCO's $185 million debt made up of both federal Rural Utilities Service ("RUS") guaranteed Federal Financing Bank ("FFB") loans and National Rural Utilities Cooperative Finance Corporation ("CFC") debt, of which $156 million is FFB debt.
- The Proposed Rule violates the Rural Electrification Act ("REA") and the 80-year federal mandate that the electric cooperative system provide reliable, low-cost electricity to rural America. AEPCO will be forced to violate its obligations under the REA mandate, as well as other state, Federal Energy Regulatory Commission ("FERC"), North American Electricity Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC") requirements to serve its members with low-cost, reliable electric service.

ADDITIONAL FLEXIBITILES FOR SMALL ENTITIES DISCUSSED DURING MAY 14, 2015 PANEL

- AEPCO believes that a mass-based trading approach is easier conceptually, we are concerned about the penalties imposed by the approach EPA has outlined for a rate-to-mass approach. We believe either approach should afford small entities flexibility.
- AEPCO supports a Federal Plan that would give small entities the ability to determine compliance based on a longer averaging period.
- The Federal Plan should cross reference existing programs for energy efficiency and renewable energy.
- Maintaining coal fired units is very capital intensive. To ensure we have the capital to upgrade pollution controls and maintain the fleet, we continue to depend on the electric program through the Rural Utilities Service for loans.

PROPOSED SOLUTION

AEPCO has proposed two approaches that EPA should consider in reducing the disproportionate cost borne by a few, making the Proposed Rule more equitable, while still achieving the bulk of the carbon reduction.

Small Public and Cooperative Utility Subcategory Proposal

As outlined in AEPCO's comments submitted on September 29, 2014, to EPA (EPA Docket No. EPA-HQ-OAR-2013-0602), AEPCO believes that EPA should create a subcategory for small public and cooperative utilities that are disproportionately affected by the Proposed Rule.

Proposed 40 C.F.R. § 60.5765(b)

(b) In lieu of meeting the state-wide goal established in 40 C.F.R. § 60.5765(a) and Table 1, a small public or cooperative utility may request a State to establish an alternative rate-based or mass-based emission performance goal for affected EGUs owned by a small public or cooperative utility on January 8, 2014 in accordance with this subsection.

(1) For purposes of this subsection, a "small public or cooperative utility" is a governmentally- or cooperatively owned non-profit entity primarily engaged in the generation, transmission, and/or distribution of electric energy for sale with total electric output (including affiliates) of 4 million megawatt hours (MWh) or less during the baseline period.

(2) A small public or cooperative utility qualifies for the alternative limit in this subsection if, after implementing all reasonably cost effective affected unit heat rate improvements, dispatching all existing natural gas combined cycle affected units owned and operated by the entity at 70% annual net capacity or, in the case of units owned but not operated, offering for dispatch all existing natural gas combined cycle affected units at the entity's proportionate share of 70% annual net capacity, and accounting for any renewable resources (other than hydropower or existing nuclear generation) owned by the entity, the following are true:

(i) one or more affected EGUs (the "non-achieving unit(s)") owned by the small public or cooperative utility cannot achieve the interim goal on a rate basis using only the small public or cooperative utility's affected units and renewable resources and any existing state-mandated energy efficiency requirements;

(ii) the non-achieving unit(s), individually or collectively, make up 20 percent or more of the small public or cooperative utility's net generation in the baseline period;

(iii) shutting the non-achieving unit(s) down will occur prior to the end of the remaining useful life as determined by the utility regulatory commission having jurisdiction, if any, or the permitting authority, if none; and

(iv) the cost of building an equivalent sized NGCC, NSPS-compliant, unit or units to replace the non-achieving unit(s) plus servicing existing debt for the non-achieving units would, in the judgment of the state, be excessive.

(3) For each small public or cooperative utility that owned an affected EGU on June 18, 2014 and continues to own that non-achieving unit satisfying the criteria in paragraph (b)(2) of this section, the State may exclude such non-achieving unit(s) from calculating its state-wide goal in Table 1 of this subpart and establish an alternative goal under its state plan as follows:

(i) During the interim goal period:

(A) Each non-achieving unit owned by the qualifying small public or cooperative utility must implement all reasonably cost effective measures to improve heat rate, which must include enforceable increments of progress, not to exceed five years from plan approval;

(B) The qualifying small public or cooperative utility shall increase dispatch of all existing NGCC units it owns and operates to the maximum extent feasible, up to a 70% utilization rate and, for units it owns but does not operate, shall offer such unit for operation up to the utility's pro rata share of 70% annual utilization; provided, however, that if the increased dispatch of NGCC units results in the non-achieving unit being reduced below its reliability limit, the state plan may provide for either periodic curtailment or earlier retirement of the non-achieving unit so long as total carbon mass is not increased over what would be achieved by 70% utilization of NGCC units owned by the small public or cooperative utility during the interim goal period or appropriate pro rata share of units owned only in part by the small public or cooperative utility.

(C) The qualifying small public or cooperative utility shall install renewable energy capacity or obtain renewable energy credits (in a state plan recognizing such credits) equal to at least 10% of non-achieving unit(s) capacity within five years of plan approval or 2025, whichever is later.

(D) The qualifying small public or cooperative utility, if it has local distribution, shall achieve at least one-half of any applicable state energy efficiency requirements set forth in the state plan.

(E) The qualifying small public or cooperative utility shall achieve a net reduction of its carbon intensity through the measures specified in paragraph (b)(3)(i)(A) through (D), plus additional increments of process specified in the state plan for such small public or cooperative utility, equal to the lesser of the following (excluding nuclear and hydropower):

(I) an amount that achieves for the small public or cooperative utility an emission rate equal to the state Final Goal established in Table 1 of Subpart UUUU by 2030; or

(II) an amount that achieves a 15 percent reduction from the baseline carbon intensity of the small public or cooperative utility.

(III) for units that the small public or cooperative utility owns only in part, the calculations of this paragraph (b)(3)(E) shall be made based on its ownership share in the units.

(F) The qualifying small public or cooperative utility must achieve at least 33% of the reduction required in subsection (b)(3)(i)(E) by 2020 or three years after plan approval, whichever is later.

(ii) During the final goal period, the state plan shall provide that the qualifying small public or cooperative utility must take one of the following actions:

(A) Shutdown the non-achieving unit(s) at the start of the final goal period; or

(B) If any non-achieving unit(s) will remain in operation, then the qualifying small public or cooperative utility shall continue any measures imposed on the non-achieving unit(s) and the utility by the state plan and shall install additional renewable energy or obtain renewable energy credits (in a state plan recognizing such credits) beyond the quantity required in subparagraph (b)(3)(i)(C), equal to at least 10% of the non-achieving unit(s)' capacity prior to the start of the final goal period. Additional renewable energy offsets equal to 10% of the non-achieving unit(s)' capacity must be obtained prior to each fifth anniversary of the final goal plan effective date if the unit is to be kept in operation beyond the anniversary date. These offsets are in addition to any other renewable energy requirements in the state plan that are applicable to all utilities.

(iii) Except as provided in paragraph (b)(3)(iv) of this section, a non-achieving unit may not operate pursuant to this subsection (b) beyond the end of its remaining useful life established by the utility regulatory commission having jurisdiction, if any, or the permitting authority, if none. The shutdown date for each non-achieving unit shall be included in the state plan.

(iv) A small public and cooperative utility that has non-achieving units that would be able to achieve the state final goal set forth in Table 1 of this subpart on or before December 31, 2039 may transition from this subcategory back to the State Plan by obtaining a revision to the state plan approved by EPA. A non-achieving unit that transitions back prior to December 31, 2039 shall not be subject to the mandatory shutdown provision of paragraph (b)(3)(iii), but shall comply with all requirements of the state plan applicable to that unit.

(4) A state may establish more stringent requirements for a qualifying small public or cooperative utility.

As indicated in AEPCO's comments filed on September 29, 2014, this proposal would affect approximately 100 small public and cooperative entities if the 4 million MWh of sales definition is used and significantly more if the Small Business Administration definition is used. AEPCO's analysis determined that it is likely that the small public and cooperative utility subcategory would result in less than a 1% leakage rate from the carbon reduction that EPA is seeking.

<u>The Arizona Utilities Group (AUG) Proposal</u>

AEPCO also urges EPA to consider a solution set forth in the comments of the AUG, which has recommended a solution that reduces the costs of compliance while lessening the reliability problems and maintaining the bulk of the carbon reductions under the Proposed Rule. The AUG recommendation is as follows:

1. For purposes of goal setting under Building Block 2 (BB2):
   a. Redispatch from coal-fired EGUs to NGCC EGUs should occur upon the later of any of the following, if redispatch would occur prior to January 1, 2030:
      i. January 1, 2020;
      ii. January 1 of the year following 40 years after initial commencement of operation; or
      iii. January 1 of the year following 20 years after commencement of operation of major pollution control retrofit, such as selective catalytic reduction ("SCR"), flue gas desulfurization ("FGD"), or baghouses at any EGU if installation occurred prior to issuance of the Final Section 111(d) rule, or after commencement of operation of selective non-catalytic reduction ("SNCR") or electrostatic precipitators ("ESPs") at an EGU owned by a small utility as defined by the Federal Energy Regulatory Commission ("FERC") if installation occurred prior to the first year of the compliance period (i.e., 2020).
   b. For coal-fired EGUs that either shutdown or convert to natural gas-fired operation, redispatch would occur as specified in an applicable implementation plan or enforceable Title V permit, provided that such commitment is entered prior to the effective date of the final rule and the date of shutdown or natural gas conversion is prior to January 1, 2030.
   c. Coal-fired EGUs that do not redispatch prior to January 1, 2030, under paragraphs 1.a or 1.b remain coal-fired EGUs for purposes of calculating the Interim and Final Goals.
2. For purposes of goal setting, when redispatching to NGCC, a rate of 1,000 lbs CO_2/MWh should be used, consistent with the most stringent standard in the EPA's proposed New Source Performance Standard ("NSPS") for EGUs.
3. The State should establish the Interim Goal in its State Plan based upon EPA's Building Block approach as modified by paragraphs 1 and 2 above.

AEPCO recommends that EPA adopt both the proposed small and cooperative utility subcategory and the AUG proposal.

Rural Electrification, Rural Electric Cooperatives and AEPCO

In 1935, President Franklin D. Roosevelt established the Rural Electrification Administration ("REA") by executive order and tasked it with bringing affordable electricity to rural communities across the country. *Establishment of the Rural Electrification Administration*, Exec. Order No. 7037, May 11, 1935. By passing the Rural Electrification ("RE") Act of 1936, Congress formally established the REA as a federal agency and made its mission to power America's rural communities and to improve access to electricity a matter of statutory mandate. The REA became a part of the Department of Agriculture in 1939. Since 1939, Congress has consistently acted to ensure that the REA, and its successor, the Rural Utilities Service ("RUS"), successfully provided electric service to the entire country.

Congress and the REA recognized that federal support was essential to the electrification of rural America because established utilities generally served high-density areas and did not serve farmers and other rural Americans. Particularly due to the lower population densities of rural areas, these utilities had no financial incentive to do so. Partnering with rural electric cooperatives was (and remains) fundamental to achieving the goals of the Rural Electrification Act.

Today, over 95% of all rural Americans have access to electricity. The RUS Electric Programs have, either directly or indirectly, in some way funded all of the generating units owned and operated by generation and transmission cooperatives ("G&Ts") and almost half of all rural electric line construction in the nation. These programs continue to provide the capital needed to upgrade, expand, maintain and replace America's rural electric infrastructure including pollution controls for generating units. Through the Electric Programs and partnerships with over 900 rural cooperatives, the federal government is the majority note holder for approximately 700 electric systems borrowers in 46 states, with loan levels over $47 billion.

DETAILED COMMENTS

Coal generation is essential to serving this country's electric load, ensuring that the owners and operators of coal generation remain viable and preventing dramatic increases in electricity rates. Due to their relatively small customer base, rural electric cooperatives are particularly vulnerable to the impacts of reduced coal generation ahead of the end of those EGUs useful life. In addition, without relief granted to small public and cooperative utilities, these disproportionate impacts will fall on the poorest electric consumers in the country. This is unacceptable.

AEPCO, even more so than other G&Ts, will be forced to violate the mandate that it provide reliable, low-cost electricity to its members. AEPCO cannot achieve the Proposed Rule's Arizona emissions rate goals without shutting down the Apache coal-fired EGUs ST2 and ST3, which will leave AEPCO substantially short on generation. Without this reliable, high capacity generation, the Proposed Rule seeks to force AEPCO to natural gas combined-cycle resources and renewable energy to serve load that was met by coal generation. At this point

AEPCO does not have (or have access to) sufficient natural gas combined-cycle and renewable energy generation to meet its load. Without adequate system generation AEPCO cannot reliably serve its load.

Because the Proposed Rule will leave AEPCO without sufficient generation, it will be forced it into the spot energy market and other extremely costly capacity and energy options to serve its members. G&Ts like AEPCO are not-for-profits and do not have shareholder equity or any other means to deal with cost increases other than to pass them onto electricity rates. These increases in AEPCO's electricity costs, therefore, can only result in dramatic rate increases for its members. AEPCO's rates are paid by some of the poorest Americans. G&T ratepayers are not in a position to absorb significant rate increases and, to the extent possible, will choose to voluntarily reduce service and suffer from a lesser quality of life.

AEPCO believes, as do others responsible for grid reliability, that the Federal Plan should provide a "safety valve" to allow continued operation of EGUs that are determined to be "critical" for grid reliability. AEPCO believes that FERC, or the North American Energy Reliability Corporation ("NERC"), the reliability entity designated by FERC, or possibly state utility commissions, should be authorized to review the operation of the overall electric grid and identify any units that are "necessary for grid stability and reliability" as exempt from re-dispatch requirements under Building Block 2 as well as state goal-setting. While FERC, NERC or state utility commissions are in the best position to determine what units are "necessary for grid stability and reliability," AEPCO believes such units may include EGUs that because of their location provide essential reliability services to portions of the grid that cannot be serviced by other units. Shutting such units down would jeopardize electric grid stability and reliability. Because of the nature of the grid, which tends to have multiple sources of generation for substantial urban areas, many of these grid stability and reliability situations may arise in more rural areas. AEPCO believes that jeopardizing grid reliability in these areas is inconsistent with the policy of the United States expressed in the Rural Electrification Act, as well as the mission of all utilities to provide reliable electric service.

CONCLUSION

As currently drafted, the CPP places an unreasonable and inequitable burden on AEPCO to reduce its CO_2 emissions by imposing overly stringent Interim and Final emission rate goals on the State of Arizona that will impact electric system reliability, impose an unreasonable financial burden on Arizona's ratepayers, including AEPCO's members, and force early closure or reduced generation from coal-fired EGUs. The Federal Plan should allow for small entity EGUs to operate through their remaining useful lives to ameliorate some of the very real costs and burdens of the proposed Clean Power Plan.

Contact Information

For further information or questions on these comments, contact:

Michelle Freeark
Director of Safety and Environmental Services
Arizona Electric Power Cooperative, Inc.
P.O. Box 670
Benson, AZ 85602
Tel. 520-586-5122
mfreeark@ssw.coop

SUNFLOWER ELECTRIC POWER CORPORATION

A Touchstone Energy® Cooperative

. . . energy done right

Sunflower Electric Power Corporation

Comments to

EPA SER Panel on

Federal Plan Requirements for GHG Emissions from Electric Utility Generating Units Constructed on or before January 8, 2014 under Section 111(d) of the Clean Air Act

Submitted Electronically to:

Lanelle Wiggins

RFA/SBREFA Team Leader

U.S. EPA Office of Policy

By

Wayne Penrod
Executive Manager,
Environmental Policy
301 W. 13th Street
Hays, Kansas 67601
(785) 623-3313

May 28, 2015

My name is Wayne Penrod and I am the Executive Manager for Environmental Policy for Sunflower Electric Power Corporation (Sunflower) of Hays, Kansas. Sunflower was one of 12 generation and transmission cooperatives with the opportunity to participate as a representative on the SER panel. We appreciate the opportunity to provide these written comments and recommendations as a part of the SBREFA process.

I. Introduction and background

Sunflower was formed more than 60 years ago to provide wholesale generation and transmission services to six rural electric cooperatives[1] who in turn provide essential electric energy to over serving over 200,000 members in central and western Kansas. Together our member-owners serve their 200,000 members, who rely on affordable and reliable electricity for daily use for their farms, homes, and businesses.

Sunflower operates the 360-MW coal-based Holcomb 1 EGU and 710 MW of gas-based EGUs. Further, Sunflower and its members receive energy by way of power purchase agreements of up to 400 MW/h, of which up to 225 MW/h is wind-based. Further, Sunflower owns or operates and maintains approximately 2,000 miles of transmission lines at operating level voltages up to and including 345 kV, all located in central and western Kansas.

Sunflower is a member of the Southwest Power Pool, Inc. (SPP) regional reliability and transmission organization (RTO/RE), the oldest such organization in the US. As a member of SPP, Sunflower participates actively in the many committees

[1] Sunflower is owned by members Lane-Scott Electric Cooperative, Inc., Dighton, Kansas; Prairie Land Electric Cooperative, Inc., Norton, Kansas; Pioneer Electric Cooperative, Inc., Ulysses, Kansas; The Victory Electric Cooperative Association, Inc., Dodge City, Kansas; Western Cooperative Electric Association, Inc., WaKeeney, Kansas; and Wheatland Electric Cooperative, Inc., Scott City, Kansas. All are small businesses.

established by the SPP membership to accomplish its purpose, and is therefore positioned to understand the relevant complexities associated with the dispatch priorities and decisions made by SPP. SPP has recently (2014) implemented pool-wide economic unit commitment and dispatch (the Integrated Marketplace) while giving proper attention to existing reliability criteria established by the North American Electric Reliability Corporation (NERC); SPP dispatches all Sunflower EGUs consistent with its mission. Significantly, Sunflower sells all of the energy it produces from its resources to the SPP consistent with procedures established by SPP; Sunflower further purchases the energy requirements of its cooperative members and other wholesale contracts to which it is bound from the SPP, again consistent with procedures established by SPP. All energy is produced, bought, and sold by way of the SPP, including all bilateral transactions.

Rural agricultural economies are historically fragile, and ill-conceived regulation will harm our members; they will suffer lost production and lost business opportunity that cannot be remedied when, or if, you change your mind later. We have grave concerns about the future price of electricity and the economic impact the President's announced GHG-reduction strategy for existing electricity producing plants, especially the impact on small businesses.

Not all utilities are the same – some, like Sunflower, are small and have limited resources with which to meet new regulatory requirements while continuing to satisfy its member and power pool obligations. The only coal-fired generation asset owned and operated by Sunflower is Holcomb 1, a nominal 360 MW unit. Holcomb 1 is well-controlled for criteria and hazardous air pollutants, and because it has always been well-maintained it is among the most efficient facilities in Kansas. Because there is little opportunity to dramatically improve efficiency and thus reduce greenhouse gas emissions, we are concerned that the effect of EPA's federal plan, especially if it does not recognize the limitations on small entities, will further disadvantage consumer-owners.

Finally, Sunflower is a member of the National Rural Electric Cooperative Association (NRECA) and we generally endorse the comments and recommendations submitted by NRECA in this rulemaking. Specifically we strongly endorse their recommendation that EPA include the Dynamic Reliability Safety Valve within the final guidance to the states and especially in the Federal plan about which the SER panel was convened.

Like NRECA, we are disappointed that EPA was not able to provide any reasonably specific language around which SERs would offer constructive suggestions to better inform EPA of the deleterious impacts their proposal would have on small entities. Since EPA has not provided the requisite information concerning the federal plan we cannot provide our specific concerns about EPA's plan. Rather we can only offer our general concerns that may arise from a federal plan that does not properly give attention to small entities. It seems reasonable to us that EPA reconvene this panel following the federal proposal in order to best effect the purpose of the SBREFA process.

II. Comments concerning a federal plan— rate-based or mass-based

Sunflower is much concerned that EPA provide maximum flexibility when establishing an emission standard so as not to unnecessarily restrict the means by which compliance can be demonstrated. The difficulty in establishing such a standard was demonstrated within the SER panel itself. Some small entities project that compliance with a rate-based system most difficult; others find a mass-based system most difficult in their situation. There are a host of reasons for this to be the case; after all, neither the population, geography, nor economy are identical across the small business world. How then does EPA reconcile these different opinions? EPA must provide maximum flexibility by allowing either method, without favoring either, in the federal plan. It is not unreasonable to foresee different small entities within the same state preferring different methods.

It is true that either method may present inherent advantages and disadvantages relating to implementation and compliance demonstration. The methods will present different financial risks (and reward), different existing resource configurations and limitations, and different growth assumptions. That’s always the case and utilities, including small ones, have found ways to deal with that since the introduction of the Clean Air Act. EPA, having not made a specific proposal for the federal plan for review by the SER, should give “deference to the differences” when their proposal is actually made.

III. Comments concerning a federal plan— impact of low- and zero-emitting resources

Not all regions of the country are blessed with the same low- or zero-emitting resources. Some have very limited opportunities, if any at all. That hasn’t changed EPA’s plan to cause redispatch to this type of resource. How does that work? EPA just assumes it will, and so disparate impacts are assured within state plans. So, how might a federal plan levelize the certain impacts, especially for small utilities? Can they even propose a way to do so?

Sunflower has already integrated over 25% renewable wind resources into its supply mix. Other utilities within Kansas, and other utilities and independent producers for other states have likewise added wind resources onto the SPP grid in the Sunflower transmission area. Sunflower has more renewables connected now than it has peak load in the summer. There are an equal amount of projects that are under development and a similar amount that are proposed. The cost of this integration (by way of transmission reliability improvements evaluated and required by the SPP AFTER the projects are constructed) is borne disproportionately by Sunflower members. The effect of this integration depresses the incremental price of energy commanded by our low-cost coal-based EGU and even the take-or-pay wind resources. This “market” routinely disadvantages the utility that has accomplished maximum integration in Kansas, perhaps in the country. How will the federal plan alter this outcome for small entities? Can EPA even devise a means by which it does not further disadvantage a small business— in this case Sunflower— while further encouraging additional wind-based resources.

Again, EPA has not made a specific proposal, so we can only caution EPA to vary carefully consider the myriad factors, such as these, that face each utility, especially each small utility when they decide how to structure their federal plan.

IV. Other issues concerning a federal plan

EPA must also balance many other issues related to a federal plan’s impact on small entities:

- A longer compliance period should be available for small businesses, particularly since they typically operate smaller numbers of affected EGUs and will be disproportionately hampered by redispatch impacts under building blocks 2 and 3.

- A longer compliance period should be available for small businesses, particularly since they typically operate smaller numbers of affected EGUs and will be disproportionately hampered by the efficiency improvement requirements under building block 1.
- Reduce expectations for building block 4 implementation for small entities (most are not vertically integrated and therefore cannot compel or even incent consumers to undertake such projects).

V. Conclusion

We appreciate the opportunity to provide this response to EPA's convening of the panel under SBREFA. The overall GHG rulemaking being undertaken by EPA is among the largest, if not the largest and most complicated ever undertaken absent guidance by Congress. Crafting a federal plan to impose upon individual companies and facilities in the states under these conditions is more, not less intensive, and the potential financial and business impacts on small entities of a federal rule, badly done, may never be recovered by them. We strongly urge EPA to postpone the issuance of the federal plan proposal until after they have made final the basic §Sections 111(b) and 111(d) rules. America, and particularly small businesses in America, deserve no less than a fully responsive effort by EPA in this rulemaking. We strongly urge EPA to reconvene this panel with real proposals upon which the panel can debate and offer more specific suggestions to EPA.

Please contact the writer at (785) 650-9004 for specific questions or information related to these comments.