APPENDIX A: List of Materials shared with Panel and Small Entity Representatives

- SBAC presentation on the SBAR Panel Process
- Program Power Point presentation, "SBAR Briefing: Federal Plan Requirements for Greenhouse Gas Emissions from Electric Generating Units Constructed on or Before January 8, 2014"
- American Public Power Association cover email
- American Public Power Association remarks
- American Public Power Association presentation
- Seminole Electric Cooperative, Inc. remarks
- Hoosier Energy remarks
- Arizona's Generation & Transmission Cooperatives presentation

An Overview of the Small Business Advocacy Review Panel Process

Panel Outreach Meeting with SERs
May 14, 2015

Office of the Administrator
Office of Policy
Office of Regulatory Policy and Management
http://www.epa.gov/op/orpm.html

This presentation covers...

- What is a Small Business Advocacy Review (SBAR) Panel?
- How does a Panel fit into the rulemaking process?
- How do Small Entity Representatives (SERs) participate in the Panel process?
- What does the Panel do with SER recommendations?

What is an SBAR Panel?

- Chaired by EPA’s Small Business Advocacy Chair (EPA’s SBAC from Office of Policy)
- Other Panel members consist wholly of federal employees:
  - Program Office manager;
  - Office of Management and Budget (Office of Information and Regulatory Affairs (OIRA) Administrator); and
  - Small Business Administration, Chief Counsel for Advocacy.

What is an SBAR Panel? (cont'd.)

- SBREFA[1] amended the 1980 Regulatory Flexibility Act (RFA), which requires agencies to:

  "assure that small entities have been given an opportunity to participate in the rulemaking" process for any rule "which will have a significant economic impact on a substantial number of small entities."[2]

[1] Small Business Regulatory Enforcement Fairness Act of 1996

[2] 5 USC 609(a)

What is an SBAR Panel? (cont'd.)

"the panel shall review **any material the agency has prepared**..., including any draft proposed rule, [and] **collect advice and recommendations** of each individual small entity representative ..., on issues related to"[1] the following:

- Who are the small entities to which the proposed rule will apply? [2]
- What are the anticipated compliance requirements of the upcoming proposed rule? [3]
- Are there any existing federal rules that may overlap or conflict with the regulation? [4]
- **Are there any significant regulatory alternatives that could minimize the impact on small entities?** [5]

[1] 5 USC 609(b)(4)
[2] 5 USC 603(b)(3)
[3] 5 USC 603(b)(4)
[4] 5 USC 603(b)(5)
[5] 5 USC 603(c)

Where does the Panel fit within the rulemaking process?

"any material the agency has prepared"

- The RFA requires that a Panel, if one is necessary, be conducted prior to publication of a proposed rule.
- It is EPA's policy to host Panels well before a proposed rule is written so we have adequate time to incorporate SER advice and recommendations into senior management decision-making about the proposed rule.
- EPA generally does not have draft proposed rule text available at the time a Panel is convened, though we expect to discuss regulatory alternatives in as great a detail as we can.
- Participation in the outreach meetings does not preclude, or take the place of, participation in the normal public comment period at the time the rule is proposed.

How do SERs participate?

"collect advice and recommendations"

- You have the opportunity, because of your status as a small entity who is expected to be regulated by this rule, to influence the decisions senior EPA officials make about the forthcoming regulation
- Advice and recommendations collected via Outreach meetings with SERs

How do SERs participate? (cont'd.)

- You will have an opportunity to submit written comments as well as the verbal comments you provide in the outreach meetings.
- Reminder: Those of you joining this meeting to assist a potential SER (aka "helpers") are asked to limit your input, both verbal and written) to representation of the small entity or small entities you are assisting or representing.

What does the Panel do with your recommendations?

- EPA, OMB, and SBA prepare a joint Panel report:
  - Submitted to the EPA Administrator
  - Considered during senior-management decision-making prior to the issuance of the proposed rule
  - Placed in the rule's docket when the proposed rule is published

Thank You

- We realize that small entities make significant sacrifices to participate
- Thank you for taking time and effort away from your business or organization to assist the Panel in this important work

Contact Information

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United States
Environmental Protection
Agency

SBAR Briefing:

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

May 14, 2015

General Background Information

- CAA §111(d) sets up a partnership between states and EPA
- EPA's role:
  - Establish process for states to issue performance standards for existing sources
  - Provide EG to the states
  - Review and approve state plans
  - Promulgate a federal plan for states that do not submit an approvable plan
- State's role:
  - Develop and submit section 111(d) state plan for sources to meet state goals set in the EG
  - Implement the plan once approved
- What electric generating units (EGUs) may be subject to the §111(d) Federal Plan?
  - Any boiler, IGCC (integrated gasification combined cycle), or combustion turbine that meets all of the following:
    - Is capable of combusting at least 250 million Btu per hour
    - For boilers and IGCCs: Supplies one-third or more of its potential electric output and more than 219,000 MWh net-electric output to a utility distribution system annually
    - For stationary combustion turbines (including natural gas combined cycle turbines): On a 3-year rolling average basis: (1) supplies one-third or more of its potential electric output and more than 219,000 MWh net-electrical output to a utility distribution system, (2) combusts fossil fuel for more than 10% of the heat input, and (3) combusts over 90% natural gas on a heat input basis; and
    - Commenced construction on or before January 8, 2014 (the date the proposed GHG standards of performance for new EGUs were published in the *Federal Register*)

Overview

- General background information
- Small entity representative (SER) input requested
- What is the relationship between §111(d) Emission Guidelines (EG) and the §111(d) Federal Plan?
- What is the scope of the §111(d) Federal Plan?
- What are the key considerations of the §111(d) Federal Plan?
- Public comments on the Clean Power Plan (CPP)
- Rate-based approach
  - Compliance mechanism
  - Crediting
- Mass-based approach
  - Compliance mechanism
  - Crediting
  - Trading basics
- What are the potential impacts of the rule?
- Schedule

*Please note: The information in this briefing reflects potential options that may be considered. Final decisions on this rulemaking will be made public at signature.

Small Entity Representative (SER) Input Requested

- The Regulatory Flexibility Act (RFA) statute directs the Panel to collect advice and recommendations from SERs on issues related to:
  - 603(b)(3) a description of and, where feasible, an estimate of the number of small entities to which the proposed rule will apply;
  - 603(b)(4) a description of the projected reporting, recordkeeping and other compliance requirements of the proposed rule, including an estimate of the classes of small entities which will be subject to the requirement and the type of professional skills necessary for preparation of the report or record;
  - 603(b)(5) an identification, to the extent practicable, of all relevant federal rules which may duplicate, overlap or conflict with the proposed rule
  - 603(c) each initial regulatory flexibility analysis shall also contain a description of any significant alternatives to the proposed rule which accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the proposed rule on small entities; consistent with the stated objectives of applicable statutes, the analysis shall discuss significant alternatives such as:
    - The establishment of differing compliance or reporting requirements or timetables that take into account the resources available to small entities;
    - The clarification, consolidation, or simplification of compliance and reporting requirements under the rule for such small entities;
    - The use of performance rather than design standards; and
    - An exemption from coverage of the rule, or any part thereof, for such small entities

What is the relationship between the §111(d) EG and §111(d) Federal Plan?

- For the §111(d) EG, EPA determines the BSER and provides guidelines to states on development of plans; for the federal plan, EPA establishes specific source-level emission standards that are consistent with BSER and lays out how sources can comply
- §111(d) EG covers a range of topics, including:
  - Defining BSER for the source category
  - Defining flexibilities in implementing BSER (e.g., allowing averaging/trading amongst sources)
  - Defining timing and other procedural requirements related to development and submittal of a state plan
  - Defining timing for emission reductions
- The §111(d) federal plan serves to implement the provisions of the §111(d) EG
  - EPA is considering approaches that can apply directly to affected sources (e.g., rate-based or mass-based) not covered by a state plan

What is the scope of the §111(d) Federal Plan?

- Meet the CAA §111(d) EG requirements and establish standards consistent with BSER
- Because EPA is focusing on forms of statewide programs that allow averaging/trading between affected sources, there is consideration of the role that new units play
- Ensure rule requirements can be implemented and enforced for all affected sources in states that fail to submit an approvable state plan
- This could also provide a model rule that states could tailor if they wish for inclusion in state plans to meet their §111(d) requirements

What are the key considerations of the §111(d) Federal Plan?

- Potential approaches to regulating affected EGUs:
  - Rate-based approach
    - EGUs are assigned an emission rate limit and must either emit below the required limit or acquire credits to offset emissions above the required rate
  - Mass-based approach
    - EGUs must hold allowances (in mass) to cover their mass emissions
- Potential mechanisms for trading, crediting and allocations
  - Affected EGUs will be able to acquire, trade, or sell credits (rate-based programs) or allowances (mass-based programs)
  - Considering whether trading should be allowed between any holder of credits or any EGU with allowances within states subject to the federal plan or any other entity holding credits/allowances

What are the key considerations of the §111(d) Federal Plan (cont.)?

- Potential state role
  - Potential option to take direct responsibility for implementing certain parts of the plan (e.g., allocating allowances)
  - Complementary measures as part of states' general energy planning process (e.g., renewable standards, energy efficiency measures, etc.)

Public Comments on the CPP

- EPA received over four million comments on the proposed Clean Power Plan for States, Indian Country and U.S. Territories
- Comments are in part the result of an unprecedented engagement of many stakeholders:
  - State, local and tribal governments, environmental and energy offices
  - Industries representing the power sector, labor organizations, environmental organizations, community-based organizations and other groups
  - The public
  - Federal agencies
- EPA is currently reviewing all the timely comments received
- EPA is committed to conducting a transparent rulemaking process; therefore:
  - EPA is using the docket for this rulemaking to keep the public informed of all materials used in developing these guidelines
  - EPA is submitting to the docket a record of all meetings held and any information received by external stakeholders before and after the close of the comment period

Public Comments on the CPP (cont.)

- Over 30,000 unique comments were submitted to EPA
- Main comment areas include:
  - Changes to the stringency and composition of building blocks
  - State's goal calculation and consistency across the building blocks
  - Unit-level electric generating data corrections
  - Rate to mass translation
  - Glide path (i.e., challenges in achieving interim goals by 2020)
  - Concerns about EPA's legal authority to implement 111(d) in the way proposed
  - Approaches for inclusion of RE and EE for compliance
  - Concerns about enforcement considerations, particularly with respect to EE and RE
  - State plan timing, requirements and approval (e.g., difficulty for states to submit state plans in the proposed timeframes)
  - System reliability considerations
  - Energy prices and cost implications

Rate-based Approach

Potential options to be considered

- EGUs will potentially be assigned an emission rate limit based on BSER consistent with the emission guidelines
- Potential options for crediting
  - Affected sources must either emit below the required limit or purchase credits to offset emissions above the required rate for their compliance period
    - Compliance periods would be consistent with final EGs
    - A facility could average over the compliance period
  - Credits are generated by EGUs that emit below the required limit and by RE and EE sources
  - Credits may be obtained by affected EGUs that are emitting above their emission rate limit
    - Credits can be bought, sold and banked (carried over for future use), which provides compliance flexibility
    - Comments will be requested on borrowing credits (holding a deficit with intention of paying back) and the degree of borrowing
  - Considering an explicit accounting system that allows affected sources to obtain credits used for compliance (consistent with guidance included in the emission guidelines for state plans)

Compliance Mechanism: Rate-based

Potential options to be considered

- Based on BSER as described in the EG, an EGU has a prescribed rate limit (lb/MWh)
- If the EGU has an emission rate greater than its limit, it must acquire credits to demonstrate compliance
- Credits are denominated in a fashion to adjust the EGU's rate (in pounds or MWh)
- The EGU acquires credits to be applied to its stack emission rate to meet its limit
  - Credits will reduce the EGU's rate (via numerator or denominator) to demonstrate compliance
- An electronic reporting and tracking system could be used to track emissions as well as EE and RE credits
  - While it could build on existing systems, tracking of EE and RE credits would require new reporting requirements
  - Compliance would be determined and credits could be traded and allocated via a program similar to EPA's CSAPR and Acid Rain Program (although via credits not allocations)
- Seeking input on any existing processes that could be used for crediting for EE and renewables (e.g., REC markets)

Rate-based Crediting

Potential options to be considered

- Emitting sources would produce/require partial credits for every MWh of output
  - (Rate Limit – Emission Rate)/Rate Limit = # of credits generated per MWh
- Credits are bought/sold in a market for sources to acquire credits to achieve compliance
- Examples:
  - For a wind turbine generating 6,000 MWh per year it would accrue 1 credit/MWh*6,000 MWh = 6,000 credits
  - For an NGCC emitting at 800 lbs/MWh with an applicable limit of 900 lbs/MWh, it creates (900-800)/900 = 0.11 credits/MWh
    - If the NGCC generated 100,000 MWh during the year, the NGCC would accrue 0.11 credits/MWh*100,000 MWh = 11,000 credits
  - For a coal unit emitting at 2,000 lbs/MWh with an applicable limit of 1,500 lbs/MWh, it creates (1,500 – 2,000)/2,000 = -0.25 credits/MWh
    - The negative value expresses a need for credits
    - If the coal unit generated 1,000,000 MWh during the year, the coal unit would owe 0.25 credits/MWh*1,000,000 MWh = 250,000 credits
  - When credits are applied for a source's compliance, the credit's are applied at the emission rate of the source

Mass-based Approach

Potential options to be considered

- Implementation of a mass-based approach consistent with BSER
- EGUs must hold allowances (in mass) to cover their emissions during the compliance period
  - Compliance periods would be consistent with final EGs
    - If EGs provide for multi-year compliance periods, the FP proposal would too
  - A facility could average over the compliance period
    - If a compliance period is 3-years long, then a facility can average over 3 years
- Allowances can be bought, sold, and banked (carried over for future use), which provides compliance flexibility
  - Any entity may participate in the allowance market
  - Comment sought on borrowing
- Allocations
  - Allocations for affected EGUs may be based on historic data
  - Possible set-asides for specific reduction efforts
  - Possible approach where a state may choose to determine its allocation distribution approach via an abbreviated state plan

Compliance Mechanism: Mass-based

Potential options to be considered

- The total number of allowances distributed in a state equals the state's mass equivalent goal, delineated by the EPA's BSER determination
- An EGU must hold sufficient allowances to cover its emissions (CO_2 mass) during each compliance period
- An EGU may obtain allowances through initial allocation, subsequent market transaction, or both
- Could use an allowance tracking and compliance system similar to existing systems in use for CSAPR and the Acid Rain Program to provide an efficient, automated means for covered sources to comply, and for EPA to determine whether covered sources are complying, with the provisions of the mass-based trading program
  - Emissions reporting could use the existing Acid Rain/GHG reporting structure

Mass-based Trading Basics

Potential options to be considered

- Total mass emissions limit for a group of sources set for a fixed compliance period
  - Limit equivalent to state goal set in final §111(d) rule
- Mass limit divided into allowances, each representing an authorization to emit a specific quantity of pollutant (e.g., 1 metric ton per year of CO_2)
- EPA distributes the allowances, which can be bought, sold or banked for future use
- For each compliance period, each facility measures and reports all of its emissions from affected EGUs
- At the end of the compliance period, each facility must surrender allowances to cover the quantity of pollutant (e.g., CO_2 mass) emitted by its affected EGUs

Potential Impacts of the Rule

- The Clean Power Plan EG proposal estimated the cost per metric ton of CO_2 reduced for each building blocks, as presented here:
  - Increase efficiency at coal steam power plants: About $8 per metric ton CO_2
  - Shift generation to low-emitting natural gas combined cycle: About $30 per metric ton CO_2
  - Increasing generation from renewable energy: $10-40 per metric ton CO_2
  - Increasing demand-side energy efficiency: $17-24 per metric ton CO_2 will rely upon the analysis performed for the development of the Clean Power Plan EG

- Seeking input on options to consider that may ease impact to small business
  - Providing flexibility in approaches for demonstrating compliance via a trading program
  - Incentivizing the continuation of effective mitigation measures to reduce GHG emissions already in practice
  - Accounting for compliance initiatives taken for other regulations
  - Whether small businesses prefer a mass-based or a rate-based approach
  - Methods for accounting for remaining useful life and stranded assets

Schedule

Milestones	Dates
Convene SBAR Panel	Spring 2015
Complete SBAR Panel	Summer 2015
Proposal Signature	Summer 2015
Final Signature	Summer 2016

From:	Hofmann, Alex
To:	Wiggins, Lanelle
Cc:	Rostker, David J.; Colin Hansen; Mason Baker; Jeff Brediger; Doc Mueller; Scott.Tomashefsky; Brandy Olson
Subject:	RE: CPP FP Panel follow-up outreach conference call with SERs - Tuesday, May 19, 10:00-11:00 (Eastern)
Date:	Tuesday, May 19, 2015 12:01:09 AM
Attachments:	SBA Submittal 051415_appa.pdf APPA_May 14 Final_Draft_presentation.pdf

Hi Lanelle,

Attached are the materials we brought to the panel for your reference.

Also, below are a few of our thoughts on flexibilities that EPA could provide through this process. During various points in the discussion we attempted to bring these up and managed to discuss them to some extent, but it seemed like the general pace of the meeting (too many topics too fast, etc.) prevented us from having a more detailed dialogue on possible flexibilities.

So, (various regulatory positions aside) based on what we believe to be the elements of the EPA FIP proposal (slides) we did our best to illustrate the following points (and/or agree with some of the points that were made by other commenters) during the meeting. We plan to file comments, but thought this might help clarify some of the flexibilities we were trying to discuss with the group during the meeting (given our interpretation of the discussion and elaboration that we would have made if there had been time before the discussion changed direction).

- Allow states to make allocation of allowance/credit decisions even after a FIP. 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 111d process.
- Use the highest 3 out of the past 5 years for baseline determination for a unit. We want to clarify that we are in support of this flexibility. For plants that weren't online in the baseline case, it should be the average of the three highest years for which the plant is fully online.
- Use multi-year averaging for compliance -- allow compliance averaging over at least 5 years. This is something that we think is an important flexibility given the EPA's own thoughts on increasing climate variability. Annual hydro variability is a good example of why this matters as well.
- Provide credits/allowances for beneficial steam use.
- Allow a FIP'd entity to choose rate or mass basis for its compliance path. Depending on the state or region there may be advantages to either method.
- Provide allowances/ credits for improved city building codes, energy efficiency programs from the utility, and other inventive methods for optimizing the electric system, such as water heater demand response. Deemed savings are a must. EPA has provided set values for other measures that reduce emissions and the FIP could also be made more flexible by allowing deemed savings to count for some credit. Make participation in any of these methods voluntary.
- Clarify that the emissions reductions/requirements do not extend to non-affected (non-large fossil fuel fired generation owning/operating) entities. They shouldn't.

- Provide adjusted timelines/additional allowances /credits for bonds/debt/etc. used for compliance with other EPA rules and/or based on infrastructure for conversion to gas where additional infrastructure needs to be built. This is particularly important in avoiding stranded costs (see handout).
- If a mass-based program is selected, reduce the burden of small communities by providing allowance mitigation for small municipal utilities on behalf of their communities in the form of free allowances. Utilities (or their communities) would have flexibility to determine how the allowance value associated with the sale of the free allowances is utilized, although its intent would be to reduce the financial burdens of investing in a cleaner resource portfolio.
- EPA should create a safe way for a city to comply with the CPP if its generating asset is in one state and its credits/allowances are earned in another state and there is no MOU between states. For example, city owns land and builds community solar in its home state for compliance with the rate for a FIPd unit in another state. Without a fix here, cities are looking at much larger compliance costs, or the possibility of no compliance option.
- Reduced reporting obligations for units less than 100MW would be helpful.
- Exempt reciprocating engines -- the EPA has exempted simple cycle turbines (what we think we heard in the meeting) for good reasons and additional flexibility would be created by ensuring reciprocating engines also do not fall under this rule.
- Beneficial electrification such as electric cars should receive allowances / credits as they will add load, but reduce air pollution at the ground level.
- Do not let 3rd parties retire emissions credits / allowances. This is critical to a functioning and cost effective allowance/credit system.
- Where additional time is needed for compliance the EPA should allow credit/allowance mechanisms that can provide additional time without effectively shutting units down. Provide a minimum utilization as a backstop against mandated shutdown.
- Add a reliability safety valve.
- Add a maximum credit/allowance price safety valve.
- Establish that new units are not part of the 111d.

If needed we would be happy to revisit these on the Tuesday call.

Thanks!
Alex

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

Accompanying Text for the Presentation by the
American Public Power Association

May 14, 2015

Introduction

Public power utilities and rural electric cooperatives offer the below discussion to complement the associated slides.

U.S Environmental Protection Agency (EPA) proposed Clean Power Plan (CPP) has the ability to rapidly transform the utility sector in an unprecedented manner. Its impact on small public power entities 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 its proposed Federal Plan (FP) will have on small entities and must act to lessen the burden of the rule on those small entities

Small Unit Generating Characteristics

Small electric generating units (EGUs) are key components of both public power and rural co-operative generating systems. Small units – historically considered those less than 200 MW of capacity – are limited their ability to deploy state-of-art heat rate-improving steps. This discussion summarizes an analysis that quantifies for 21 small units representing capacities from 25 to 125 MW the challenges of cost-effectively deploying the full of heat rate-improving steps required to attempt to meet Building Block 1 targets of the proposed Clean Power Plan.

The annual capacity factor of example small EGUs – owned by members of the American Public Power Association (APPA) and the National Rural Electric Co-Operatives Association (NRECA) – decreased from 2007 to 2013 (Graphic #5). The capacity factor in 2012 and 2013 for small EGUs is well below the average capacity factor of EGUs in the national inventory - 60% in 2012 and 52% in 2013.

CO_2 emission rates (lbs/MWh, net basis) from the example small EGUs increase over the same period of 2007 through 2013 (Graphic #6). CO_2 emission rates for 2012 for the small EGUs exceed those from larger units by 20% (Graphic #7).

Unit age does not completely explain the higher CO_2 emission rates from small EGUs. Even within the same age category, CO_2 emissions from small EGUs exceed the CO_2 emissions from the national inventory (Graphic #8). The data for EGUs exceeding 40 years of age represents 17 units and should be considered valid; the data is limited for EGUs of 20-40 years (3) and less than 10 years of age (1) and should be interpreted with caution..

A key contributor to higher CO_2 emission rates observed from small EGUs is lower load operation. For three categories of capacity factor (shown in Graphic #9) the net CO_2 emissions from small EGUs exceeds the average of the national inventory. The detrimental impact of lower load on gross heat rate is exhibited for EGUs owned by a member of APPA (Muscatine 8) and the NRECA (CR Lowman) (Graphic #10).

Higher CO_2 emission rates for small EGUs are observed for all three categories of coal fired (Graphic #11).Heat Rate-Improving Options

Seven categories of heat rate improving options, representing a range of capital cost, heat rate improvement and CO_2 avoided, in concept can be deployed to an EGU (Graphic #12). Many of these options require significant capital investment, outage time, or both – with upgrades to the steam path (e.g. rebuilding the steam turbine) a widely applied, high payoff option for conventional EGUs. Several heat rate improving options require less cost but provide less payoff – these include effective use of auxiliary power; improved boiler cleaning; and advanced process controls. An example cost analysis reported in this presentation addresses three options – steam turbine upgrade, advanced process controls (specifically, neural networks), and improved boiler cleaning (Graphic #13).

Analysis Conducted

For each of the three options the capital requirement, CO_2 emissions avoided, and the operating time required for "payback" of the investment due to lower operating cost is determined. (This analysis ignores financing costs or the levelization of operating costs over time; "payback" is simply the years of operating cost savings to offset the capital charge).

This cost evaluation is conducted for two classes of EGUs: 500 MW capacities reflecting a typical state-of-art EGU in the national generating inventory, and 100 MW capacity reflecting small EGUs. The cost evaluation assumes 75% and 45% capacity factor for the 500 MW and 100 MW units, respectively. Both units are assumed to fire coal delivered for the price of $2.25 /MBtu (Graphic #14).

Results

The capital required (in terms of $M) for the three options is determined from previous studies conducted by the Utility Air Regulatory Group[1] and the National Coal Council[2]. The capital for steam turbine upgrade can be a factor of ten higher than for advanced controls and advanced boiler cleaning (Graphic #15). The capital cost and the payoff in terms of heat rate improvement are summarized for these options in Exhibit #16.

Examining capital as normalized to generator output - cost in terms of dollars per kw ($/kW) – is instructive. This cost metric is presented versus the simple payback period (Graphic #17) for the three example options and shows for each option the 100 MW EGU requires a significantly longer payback period compared to the 500 MW case. This result is primarily due to the higher normalized capital cost (Exhibit 17) and lower capacity factor, the latter limiting savings from lower operating cost.

The CO_2 emissions avoided (lbs/MWh, net basis) by deploying the three example heat rate-improving options are reported vs. the calculated payback period (Graphic #18). High values of avoided CO_2 require longer payback periods.

Conclusion

Small EGUs are challenged to deploy the higher capital cost heat rate-improving options necessary to attempt to achieve the CO_2 reduction target of Building Block 1 of the proposed Clean Power Plan. A higher capital cost project such as a steam turbine upgrade for a 500 MW unit will lower CO_2 by 40 lbs/MWh, and require a 3 years to payback capital. For a 100 MW unit more CO_2 is avoided – 60 lbs/MWh in the example case – but the payback period is 12 years. The latter extended 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 require much lower capital – typically less than $600K for a 100 MW unit. The CO_2 avoided is 15 lbs/MWh and a 7-year payback is required.

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[1] *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.

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

APPA®

SEVENTY FIVE YEARS

National Rural Electric Cooperative Association®

A Touchstone Energy® Cooperative

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

May 14, 2015

Small Business Advocacy Review
Environmental Protection Agency

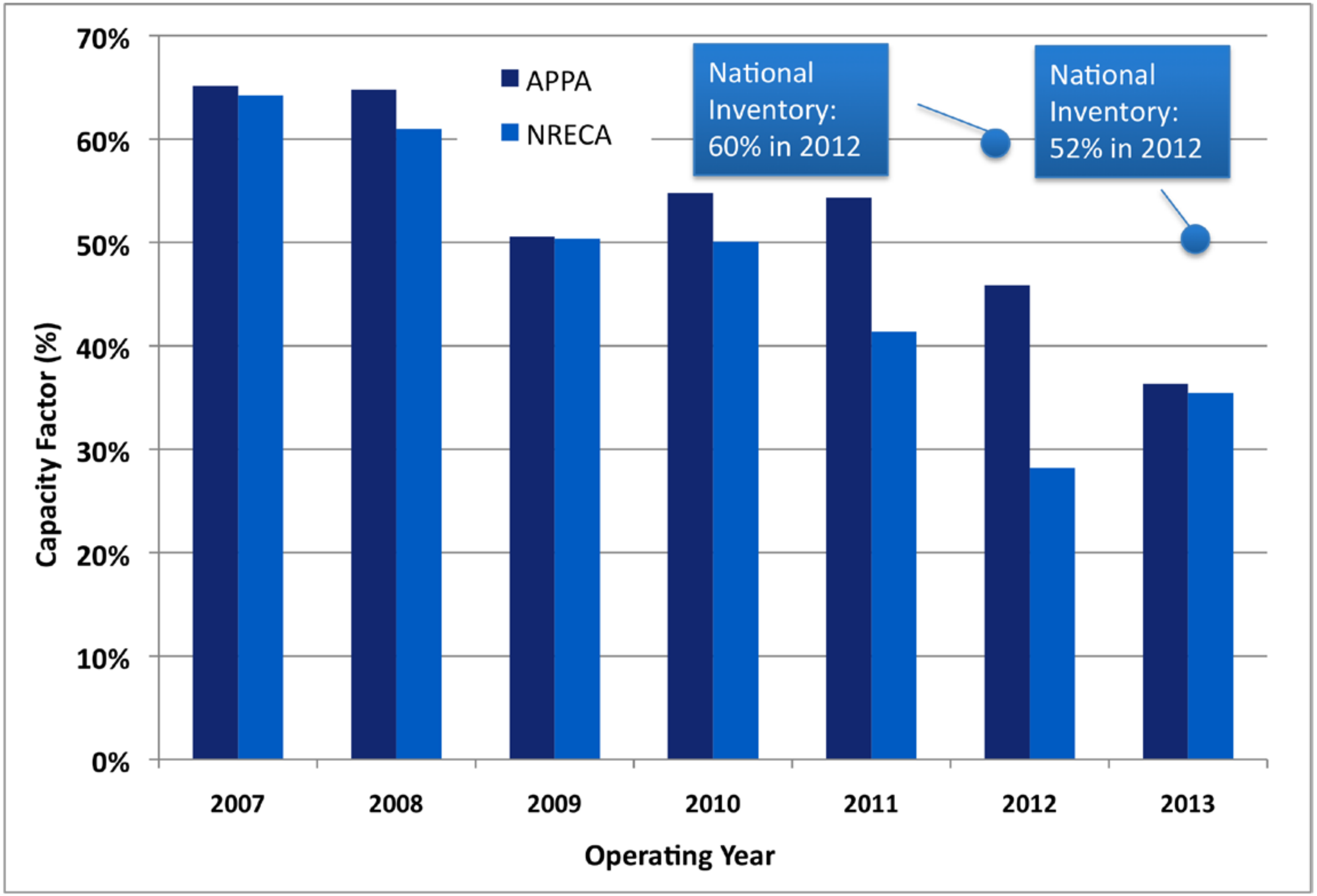
OVERVIEW

- Small Units
  - Definition
  - Capacity factor
  - CO_2 emission rate (lbs/MWh)
- Heat Rate Improving (CO_2 Reducing) Options
- Higher vs. Lower Capital Cost Options
- Quantify
  - Required capital
  - Years to "payback" investment
- CO_2 Avoided (lbs/MWh) vs. Payback
- Conclusions

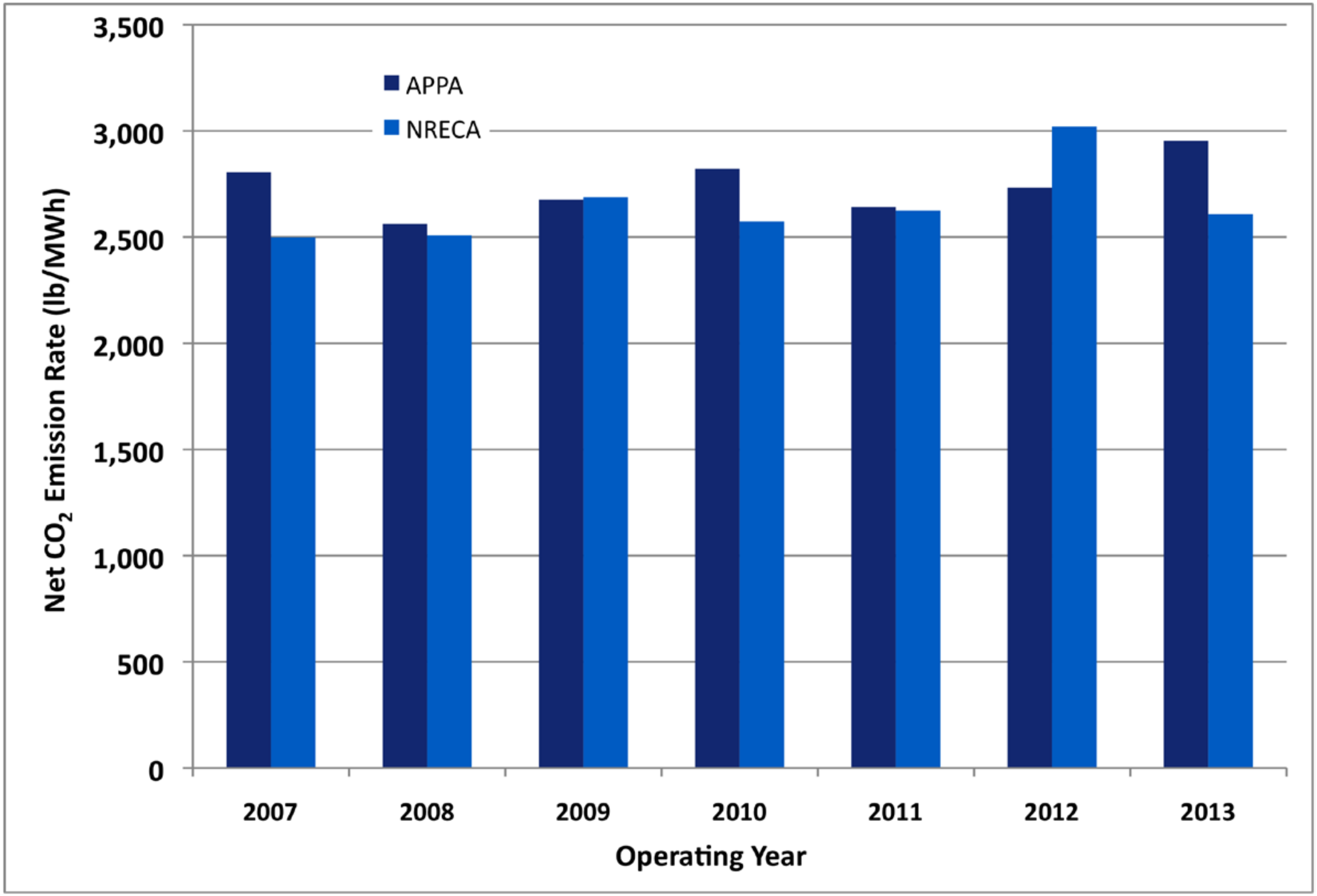
“SMALL UNITS”

- Represent an Important Component of the U.S. Generating Fleet
  - Historically ~ < 200 MW
  - This analysis: 25-120 MW
- Small Size Limits Performance, Heat Rate
  - Steam conditions
  - Greater “swing” load duty
  - Existing units older, without state-of-art equipment
- Data for this Analysis (21 Units)
  - APPA: 50-93 MW
  - NRECA: 23-130 MW

SMALL UNITS TYPIFIED BY DECREASING CAPACITY FACTOR

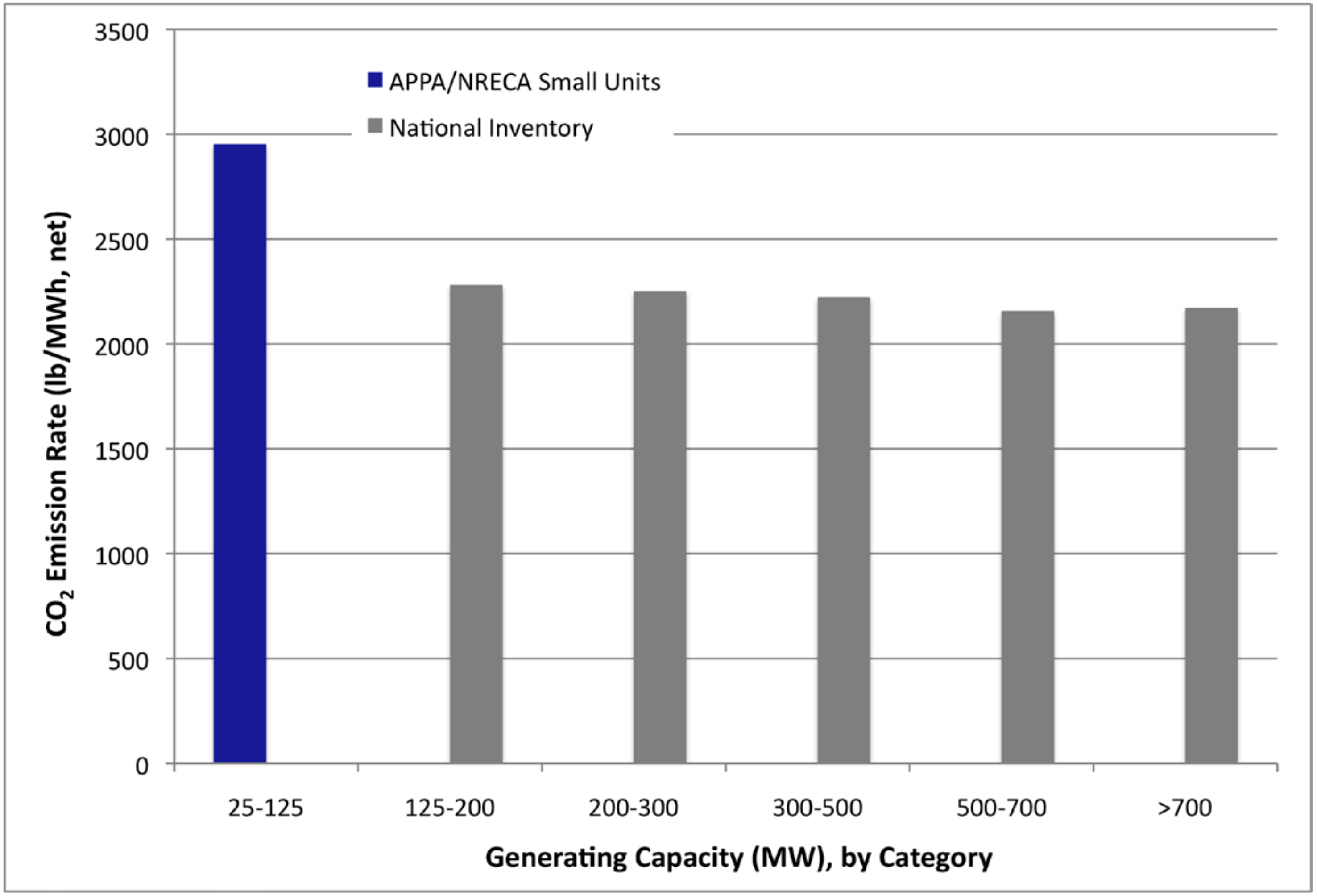


…AND INCREASING CO_2 EMISSION RATES

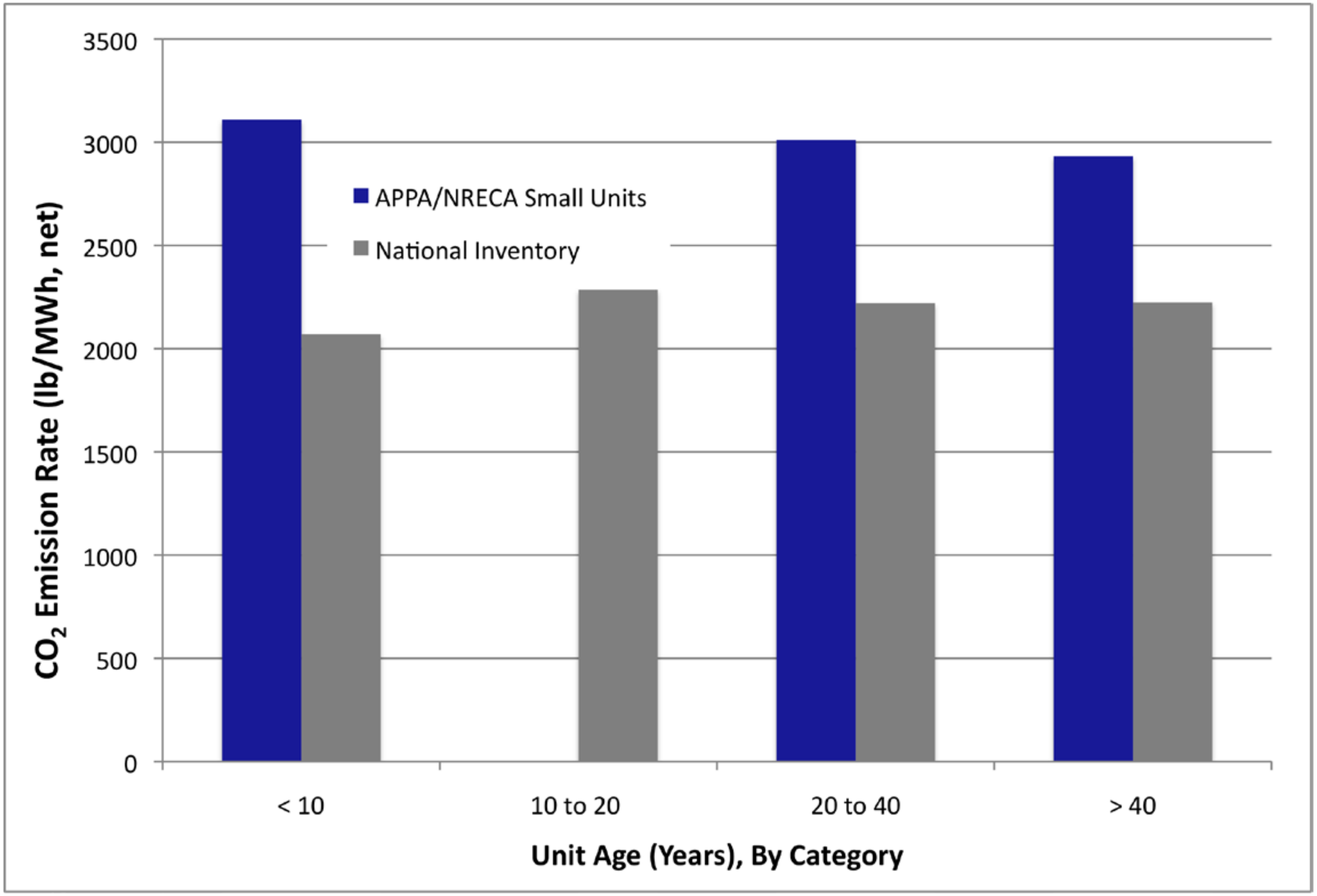


CO_2 EMISSIONS vs. GENERATING CAPACITY

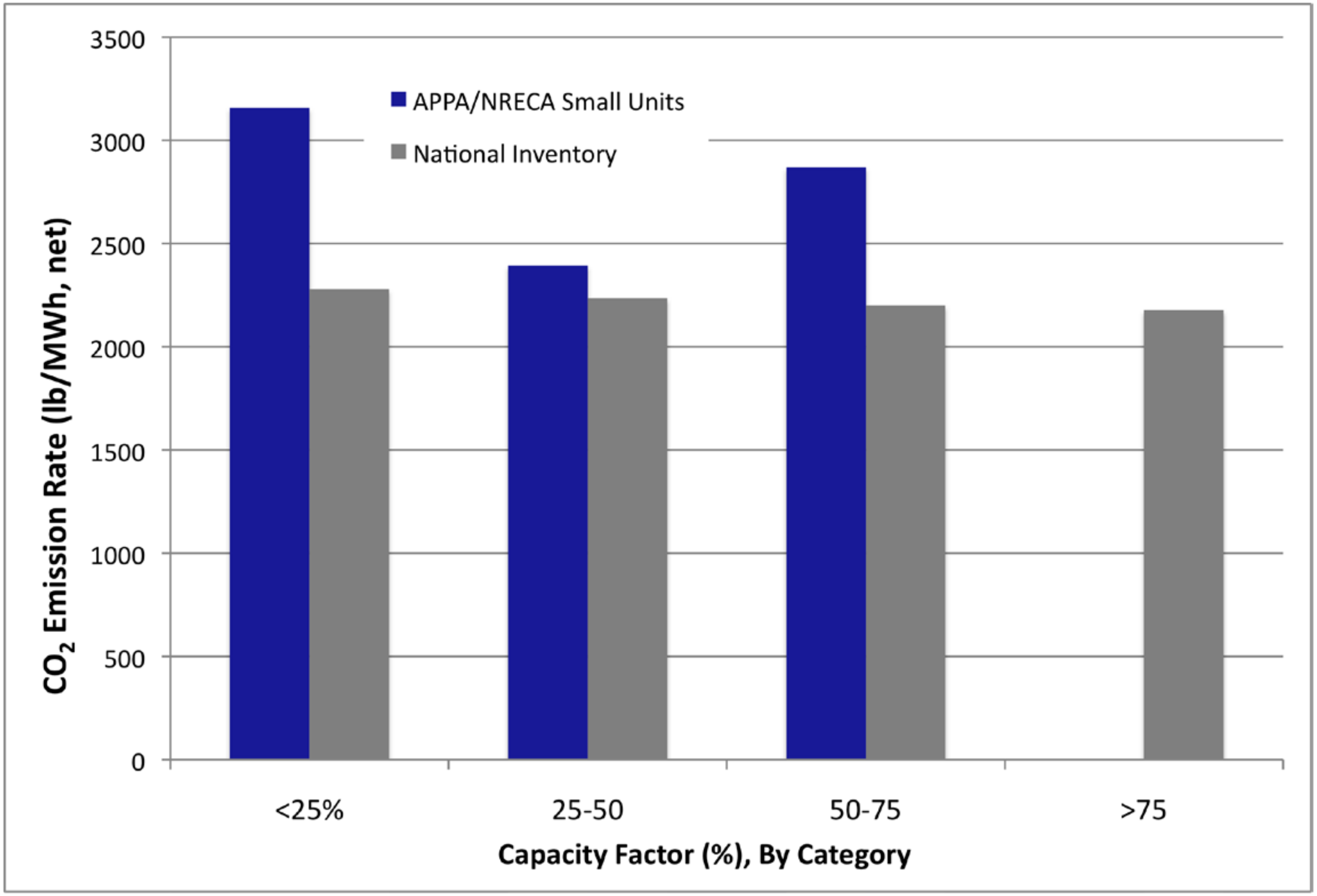
(Small Units vs. National Inventory, 2012)



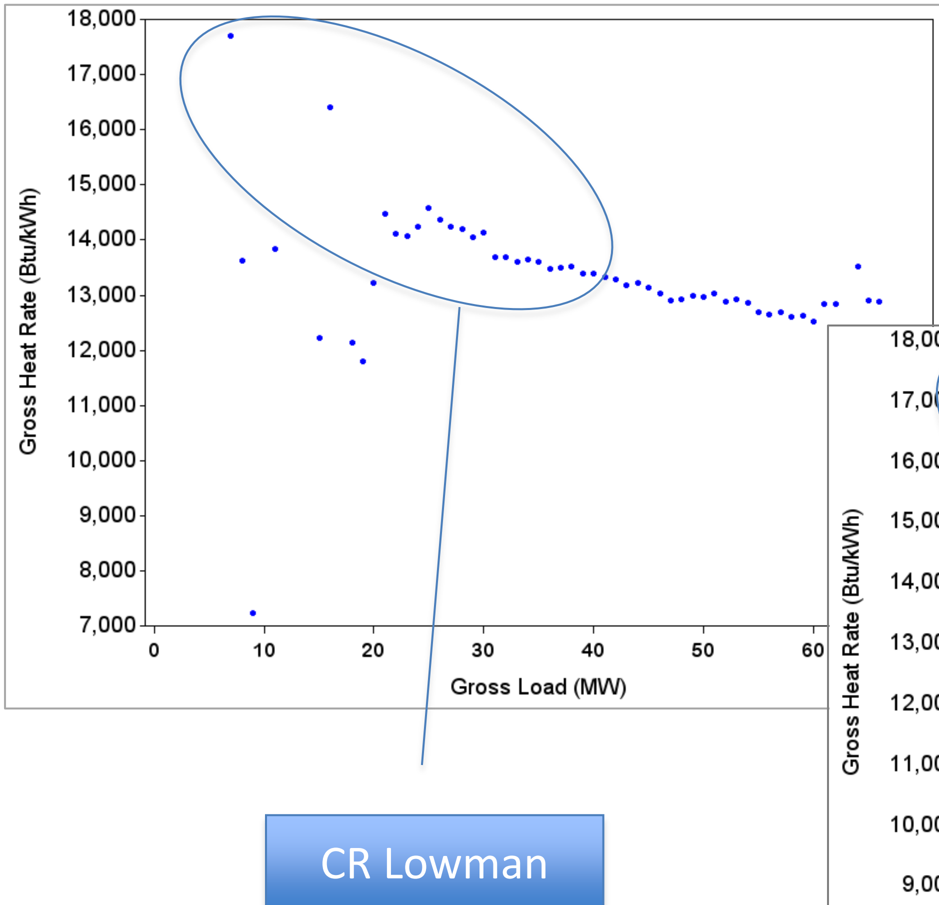
CO_2 EMISSIONS vs. UNIT AGE
(Small Units vs. National Inventory)

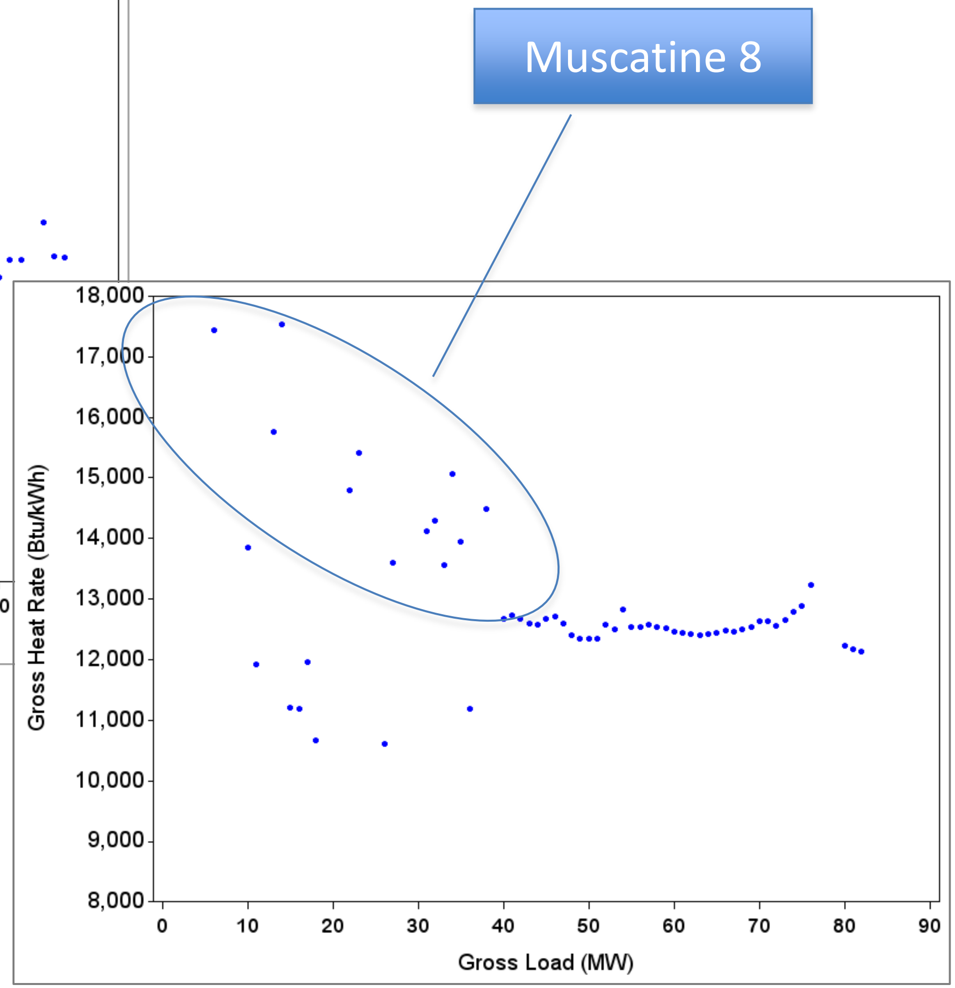


CO_2 EMISSIONS vs. CAPACITY FACTOR
(Small Units vs. National Inventory)

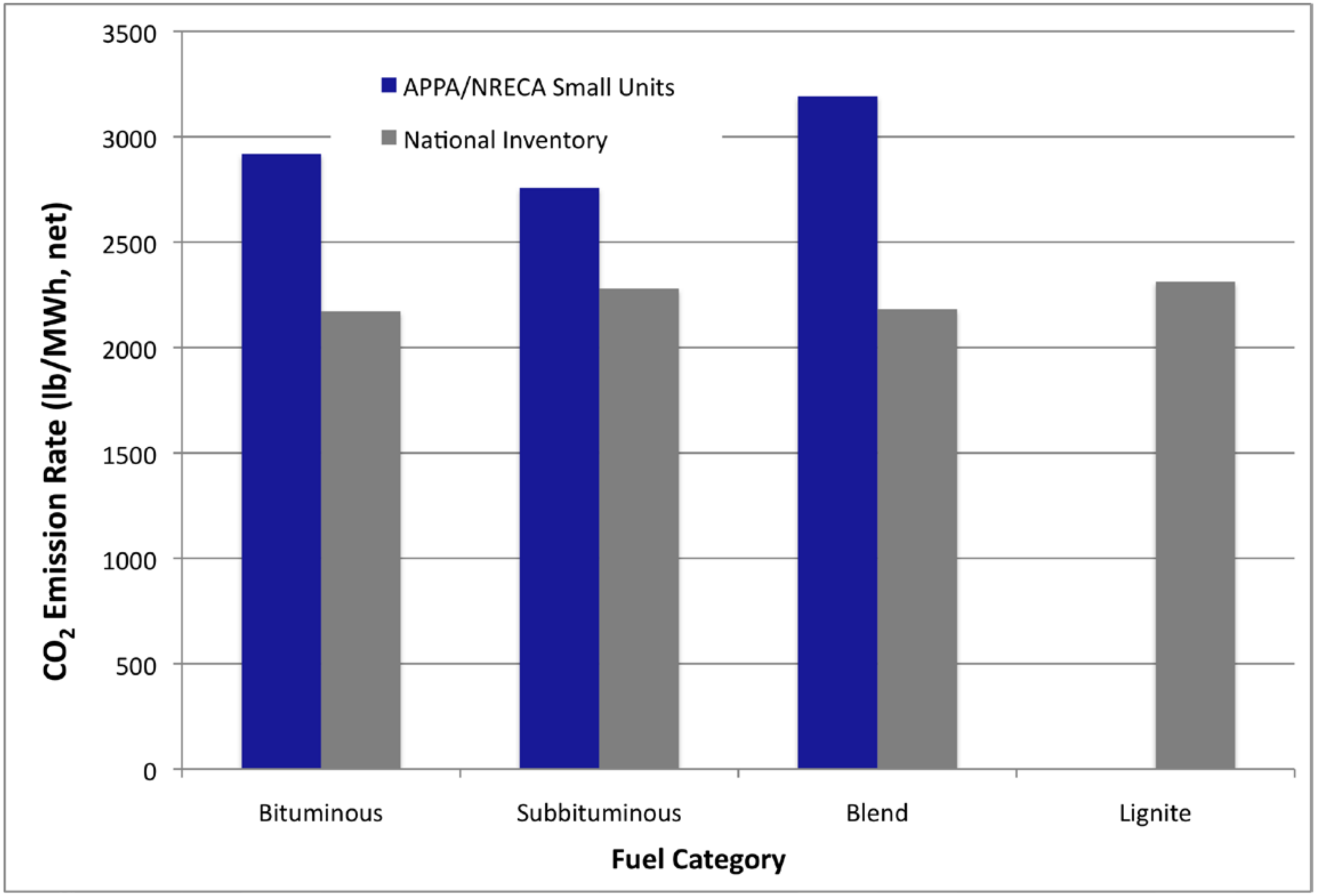


OPERATING AT ½ LOAD INCREASES HEAT RATE



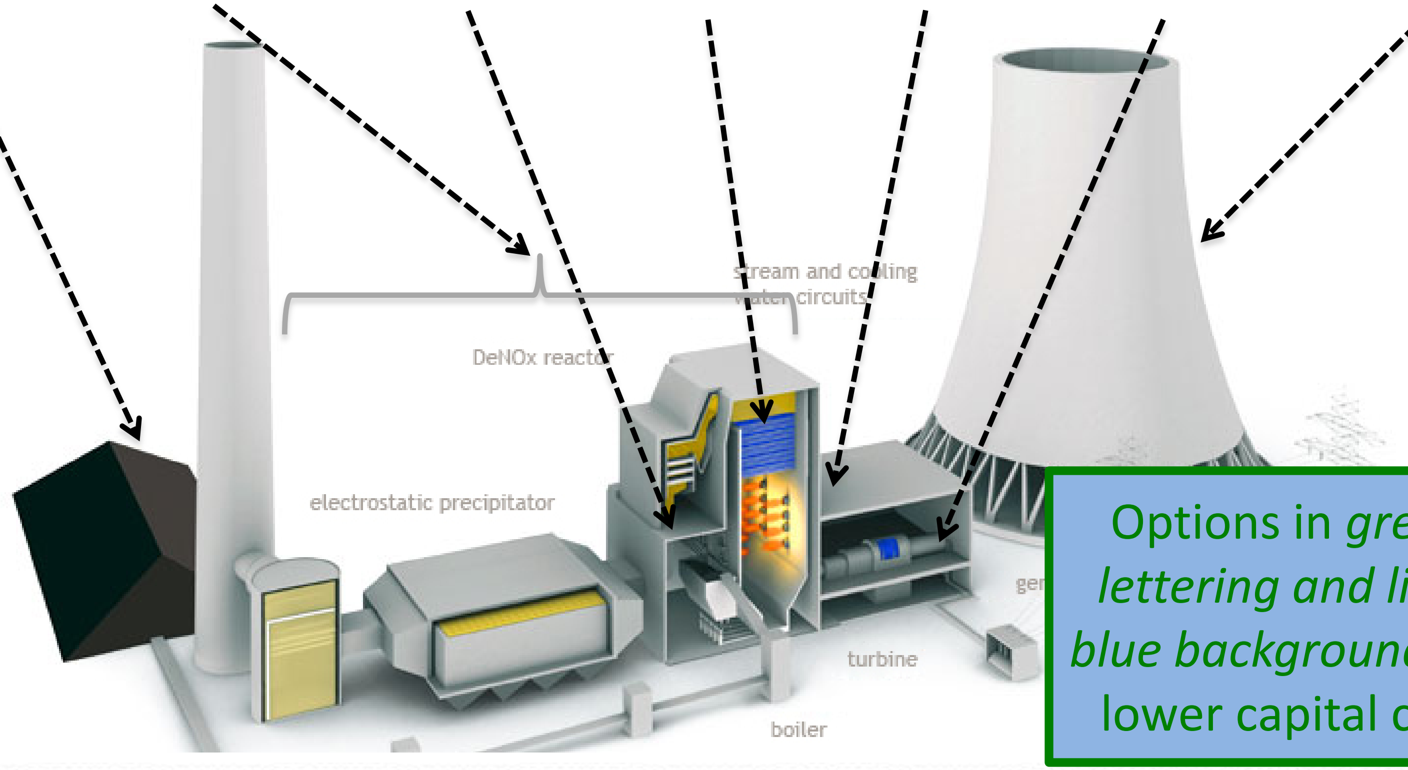


CO_2 EMISSIONS vs. FUEL TYPE
(Small Units vs. National Inventory)



PROPOSED HEAT RATE IMPROVEMENT MENU

Fuel Type, Processing	**Aux Power, Thermal Losses**	Low Temp Heat Recovery	**Boiler Heat Removal (Cleaning)**	**Advanced Process Controls**	Steam Path, Energy Extraction	Cooling System



Options in *green lettering and light blue background* are lower capital cost

HEAT RATE IMPROVEMENT OPTIONS: TWO CATEGORIES

High Capital Requirement, Extended Outage Time

- Cooling System
- Steam Path (Turbine Upgrade)
- Boiler Heat Removal
- Low Temperature Heat Recovery
- Change Fuel Source

Lower Capital Requirement, Less Outage Time

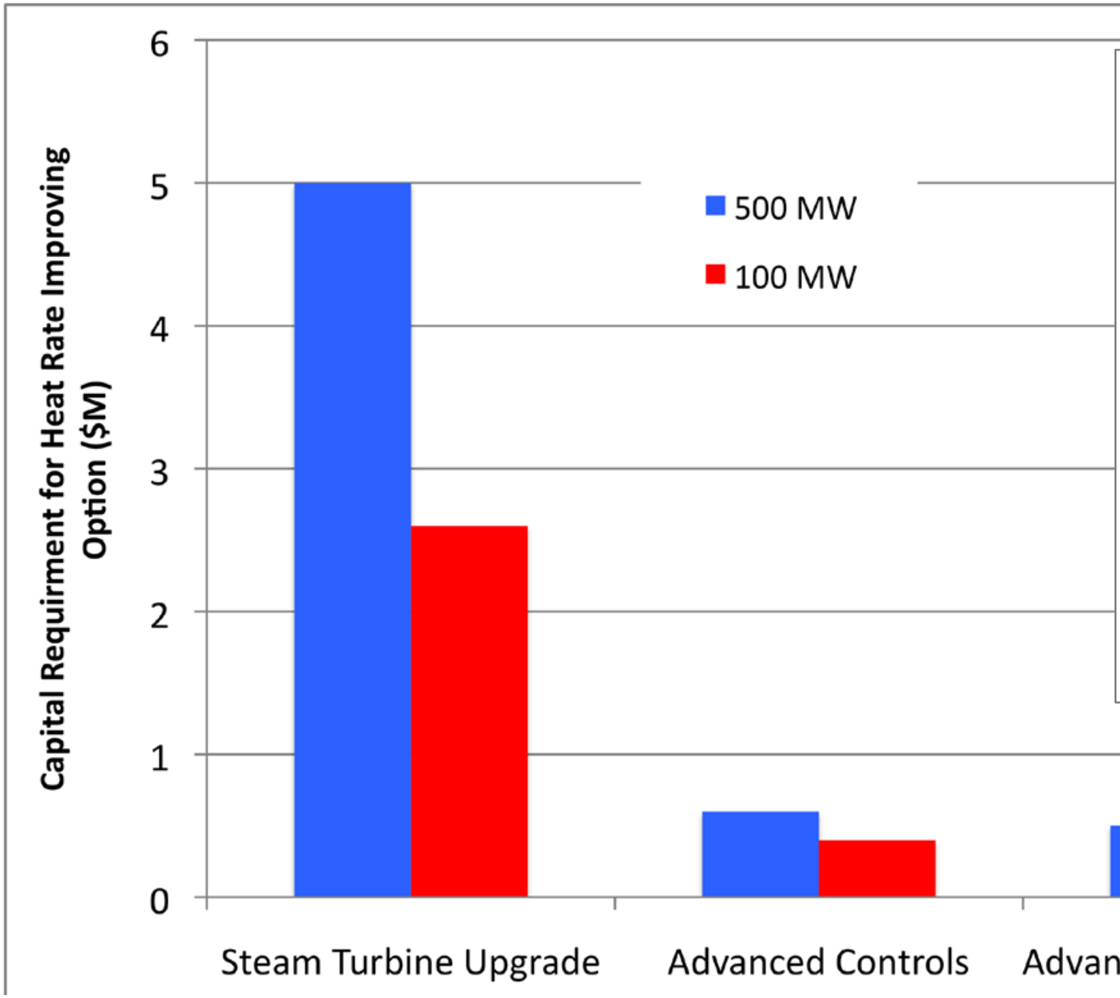
- Advanced Process Controls (Neural Networks)
- Auxiliary Power Control (Variable Frequency Drive, Neural Network Software)
- Improved Boiler Cleaning (On-line)

Options in Green Will Be Quantified As Examples

COMPARE COST, BENEFIT OF HIGHER vs. LOWER CAPITAL OPTIONS

- Determine Capital Required, Payback (in Years) to Recoup Investment
  - Higher capital option: turbine upgrade
  - Lower capital options: advanced controls, improved boiler cleaning
- Capital, Payback for 500 MW vs. 100 MW
  - 500 MW: 75% capacity factor,
  - 100 MW: 45% capacity factor
  - Delivered fuel price: $2.25/MBtu

FOR SOME OPTIONS RAISING CAPITAL REQUIRED IS A BARRIER



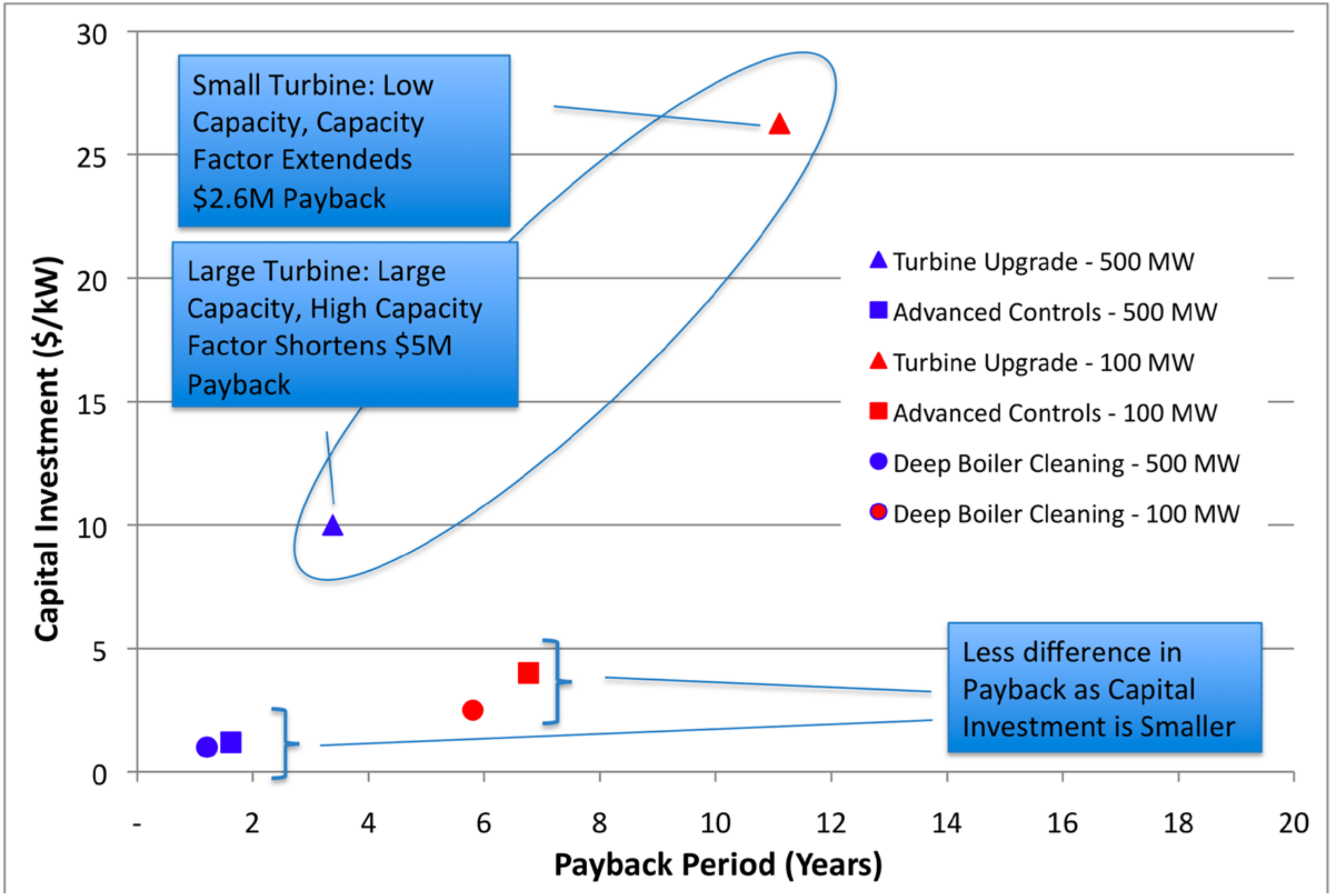
- Public Power Owners Can Be Challenged to Raise Capital
- May Be Limited Procedurally to Low Capital Options

COMPARE COST, BENEFIT OF HIGHER vs. LOWER CAPITAL OPTIONS

Option	500 MW	100 MW
Turbine Upgrade		
Capital ($M)	5	2.6
Heat Rate Improvement (Btu/kWh)	200	300
Advanced Controls		
Capital ($M)	0.6	0.4
Heat Rate Improvement(Btu/kWh)	50	75
Advanced Boiler Cleaning		
Capital ($M)	0.5	0.25
Heat Rate Improvement (Btu/kWh)	60	80

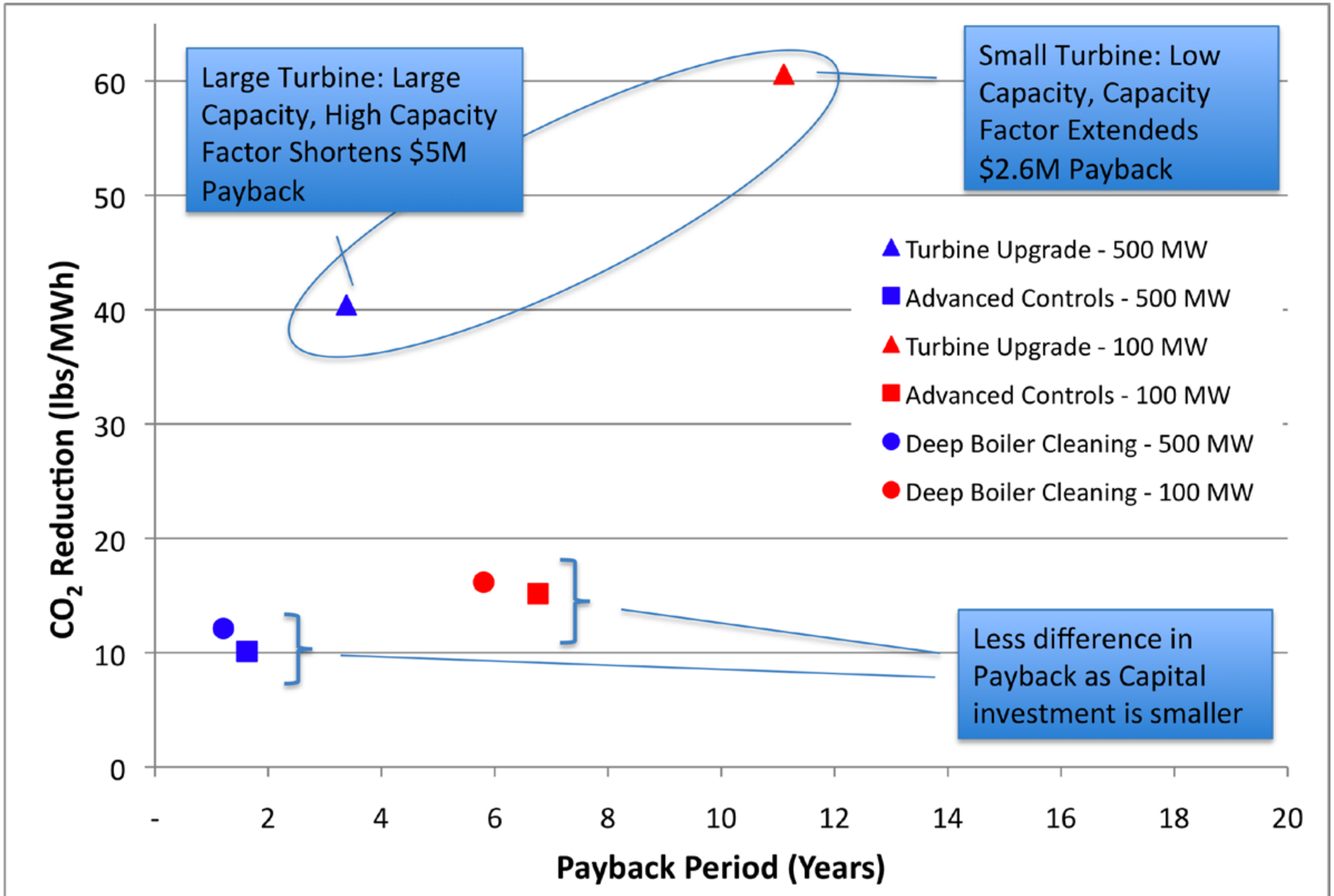
CAPITAL INVESTMENT, PAYBACK

Three Heat Rate Reducing Options: 100 MW vs. 500 MW



CO_2 AVOIDED, PAYBACK

Three Heat Rate Reducing Options: 100 MW vs. 500 MW



CONCLUSIONS: HEAT RATE IMPROVING OPTIONS

- Small Units Challenged to Deploy High Capital Cost Heat Rate Improving Options
- Higher Capital (Turbine Upgrade)
  - 500 MW: 3 Year payback, ΔCO_2 by 40 lbs/MWh
  - 100 MW: 12 Year payback, ΔCO_2 by 60 lbs/MWh
- Lower Capital (Controls, Boiler Cleaning)
  - Similar capital for either (<0.60 $M)
  - 100 MW: 7 Year payback for ΔCO_2 by 15 lbs/MWh

Seminole Electric Cooperative, Inc.

James Frauen, Vice President of Technical Services & Development

RE: Need to extend Clean Power Plan compliance dates to avoid stranding of assets and unacceptably high electric rates

Seminole Electric Cooperative, Inc. (Seminole) is a not-for-profit generation and transmission electric cooperative. Seminole provides reliable, competitively priced, wholesale electric power to nine Member distribution electric cooperatives. Approximately 1.4 million consumers and businesses in parts of 42 Florida counties rely on Seminole's Member distribution cooperatives for electricity. Seminole's primary generation resources include the coal-fired Seminole Generating Station ("SGS") in northeast Florida and the natural gas-fired Richard J. Midulla Generating Station ("MGS") in south central Florida. Seminole also owns more than 350 miles of transmission line that connect its electric generating plants to Florida's transmission grid.

In order to meet its Member load requirements, Seminole supplements its own generation with power purchased from other utilities, independent power producers and government entities. Seminole's portfolio reflects a mix of technologies and fuel types, including purchases from renewable resources. The diversity in Seminole's generation mix reduces exposure to changing market conditions, helping to keep rates competitive and to maintain reliability.

Through EPA's CPP modeling, EPA is proposing that Florida reduce its overall carbon ("CO_2") emissions by 38 percent. In order to achieve the 38 percent reduction, EPA projects that more than 90 percent of Florida's coal-fired generation will need to be retired in order to achieve Florida's interim and final CO_2 reduction goals of 794 and 740 lb CO_2/MWh, in 2020 and 2030 respectively. The retirements include Seminole's 1,300 megawatt ("MW") coal-fired power plant.

The delta between the interim and final goals is so slight that essentially all coal-fired units in the state will be forced to retire or significantly reduce emissions by 2020 to meet Florida's interim goals. Florida's final goals will allow only two coal-fired facilities (3 units in total) to remain in the state, each of which will be required to operate at significantly reduced capacities. Under the proposed targets, approximately 8,700 MW of coal-fired generation in Florida will be pre-maturely retired. This significant loss of coal-fired generating capacity within such a short time period will cause reliability impacts in the state.

If the CPP moves forward as currently planned, new gas-fired generating units will need to be constructed to meet generation demand created by the loss of the state's coal-fired facilities. The new gas-fired generating facilities, transmission infrastructure and gas pipelines cannot be permitted and constructed by 2020, even if started today, much less if started in several years when the EPA and State of Florida finalize their respective rule implementation plans. Seminole's Members, and other consumers in Florida, will be required to pay increased costs in their electric bills to accommodate construction and operation of these new facilities.

Seminole will suffer substantial harm as a result of EPA's proposal through the early retirement of its SGS coal-fired facility – consisting of two (2) 650 MW units. Seminole plans to operate SGS through 2045, at a minimum, and will lose more than 25 years of remaining useful life if the units are retired early. SGS generates more than 50 percent of the energy provided to our Members. SGS is equipped with state-of-the-art environmental controls and is one of the cleanest coal-fired facilities in the nation. Over the life of the facility, Seminole has been proactive in meeting regulatory requirements and has invested more than $530 million in environmental control technology at SGS, including more than $260 million of emission control equipment installed within the last nine years.

Seminole, as a rural generation and transmission cooperative, has primarily relied on capital borrowed from the Federal Financing Bank and loan guarantees from the Rural Utilities Service ("RUS") for the construction of its generation fleet and capital improvements to its facilities. Currently, loans related to SGS account for more than 75 percent of Seminole's total outstanding debt. If SGS were to be retired prior to the end of its useful life, the debt service related to these loans would significantly impact the electricity rates paid by our Members. Additionally, most of Seminole's loans also contain significant prepayment interest penalties, so a strategy to prepay the debt would only further increase the cost paid by our Members. Additionally, the remaining net book value (stranded asset) would be required to be written off and the expense would be paid by our Members. The Members would continue to pay the fixed costs related to SGS without receiving any energy or capacity from its operation. Seminole will still have to serve the full requirements of our Members, and the replacement capacity related to the early retirement of SGS will either have to be constructed or purchased. This will cause our Members to pay for both the stranded asset (SGS) and the new replacement capacity.

Seminole is greatly concerned about the economic impact this rule will have on our Members and their consumers. Based on a 2011 survey, residential consumers served by our Members are predominantly rural and approximately one-third have household incomes below the poverty level. More than 75 percent have household incomes less than $75,000. Lower-income households spend a substantially higher percentage of their income on electricity usage. Accordingly, any change in rates as a result of the proposed rule will impact them disproportionally.

<u>Conclusion</u>

As a result of the EPA's CPP, Seminole would suffer substantial harm with regard to economics and reliability – a reality that must be addressed. Seminole is seeking more time for compliance through elimination of the 2020 interim goal and extension of the final 2030 implementation date to allow operation of our facilities through their remaining useful life. These time extensions would minimize the economic effect of the rule on our operations and will provide Seminole and our Members the opportunity to plan and develop reliable generation and transmission resources for the future.

HOOSIER ENERGY
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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.

Arizona's G&T Cooperatives
Touchstone Energy® Cooperatives

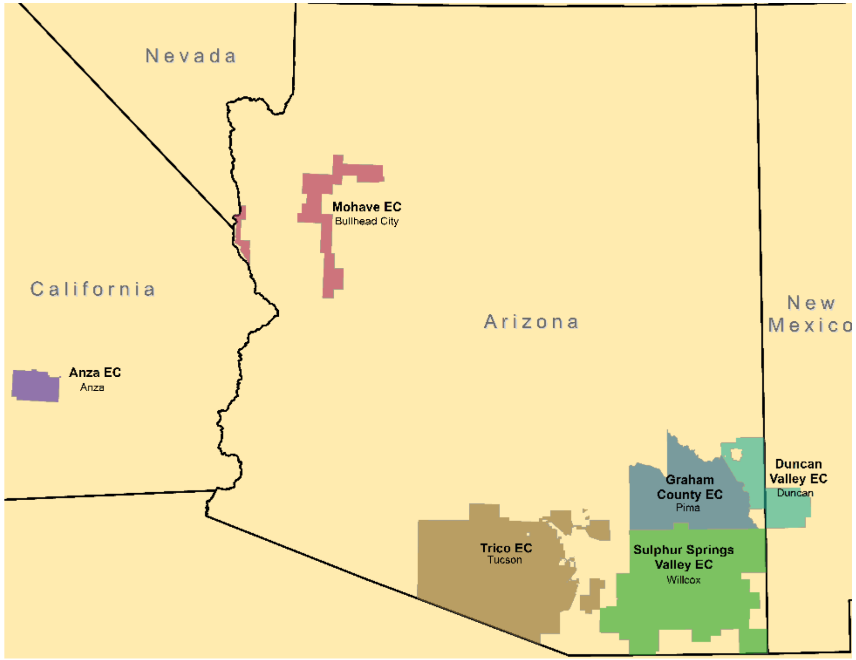
EPA's Clean Power Plan and Arizona's G&T Cooperatives

Michelle R. Freeark
Director of Safety & Environmental Services

March 14, 2015

Cooperative's Organization and Membership

- Arizona Electric Power Cooperative (AEPCO) is a generation cooperative, which owns and operates Apache Generating Station, in Cochise, AZ.
- Southwest Transmission Cooperative (SWTC) owns and operates the transmission system to deliver AEPCO's power.
- Together, 'the G&T' serves six rural electric distribution cooperatives over a large geographical area with numerous towns and small cities, serving about 150,000 meters primarily for residential use.
- The territory is rural, sparsely populated, and price-sensitive, with one third of customers living below the federal poverty line.



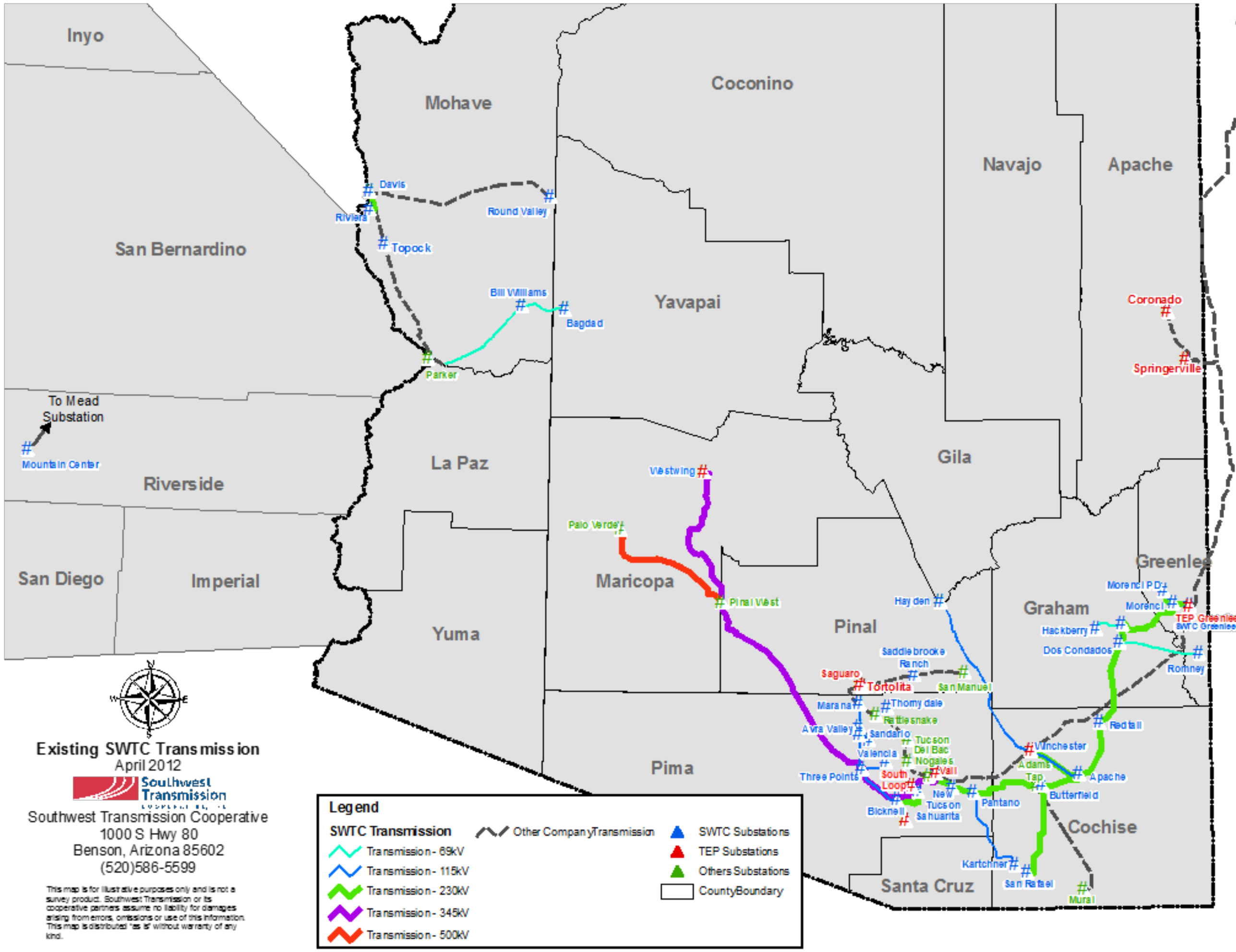
Apache Generating Station

Arizona's G&T Cooperatives
Touchstone Energy® Cooperatives

Unit	Year Built	Net Capacity	Fuel
ST1	1963	72 MW	gas
ST2	1978	175 MW	coal/gas
ST3	1979	175 MW	coal/gas
GT1	1964	10 MW	gas
GT2	1972	20 MW	gas/oil
GT3	1975	65 MW	gas
GT4	2002	38 MW	gas/oil
Total Net Capacity		555 MW	

Transmission System

Arizona's G&T Cooperatives
Touchstone Energy® Cooperatives



Cooperatives and Rural Arizona

Arizona's G&T Cooperatives
Touchstone Energy® Cooperatives

- Apache Station, 555 MW net generating capacity (two 175 MW Coal Units) located in Cochise County
- SWTC 620 miles of transmission lines and 24 substations in 7 counties
- G&T Cooperatives employ 245 union / nonunion people, more than 100 at Apache Station, most live in the surrounding area.
- Direct economic impact on rural cities, towns, and businesses

Current Membership

Class A All Requirements Members	Member Since	Headquarters	Miles of Line	Meters Served	Members Per Mile
Anza EC	1979	Anza, CA	736	5,000	5
Duncan Valley EC	1961	Duncan, AZ	453	2,315	3
Graham County EC	1961	Pima, AZ	1,217	8,700	5
Class A					
Partial Requirements Members					
Mohave EC	1973	Bullhead City, AZ	1,512	38,728	21
Sulphur Springs Valley EC	1961	Willcox, AZ	4,059	52,999	13
Trico EC	1961	Marana, AZ	3,596	39,901	10
			11,573	147,643	
Class D Member					
Valley EA	2007	Pahrump, NV			

- All-requirements members ("ARMs") purchase all the requirements necessary for serving their distribution cooperative members from AEPCO
- Partial-requirements members ("PRMs") purchase both from AEPCO and from other market sources
- Class D Member Valley takes scheduling and trading services from AEPCO

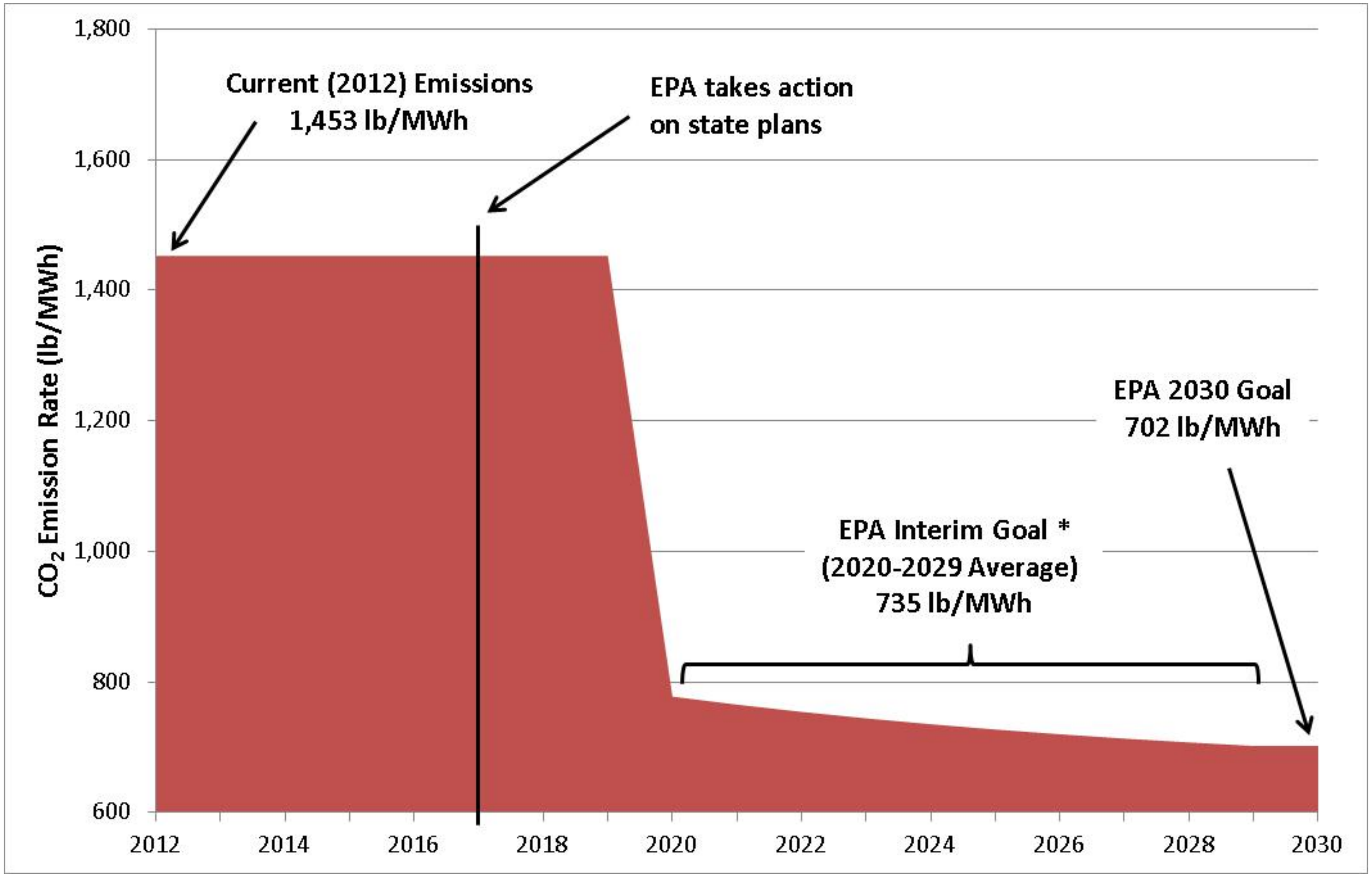
AEPCO's Concerns

Arizona's G&T Cooperatives
Touchstone Energy® Cooperatives

- AEPCO previously met with EPA over regional haze.
  - Severely affected by $192 million proposal
  - Worked with EPA to develop alternative, $30 million but 25% increase in fuel costs
  - Thought we had made AEPCO viable for medium term
- Clean Power Proposal jeopardizes gains

Arizona CPP Compliance

Arizona's G&T Cooperatives
Touchstone Energy® Cooperatives



Graphic Source:
Salt River Project, 2014

*Per EPA goal-setting, all in-state, non-tribal coal generation will be replaced by other resources by 2020 to comply with the proposed Interim Goal.

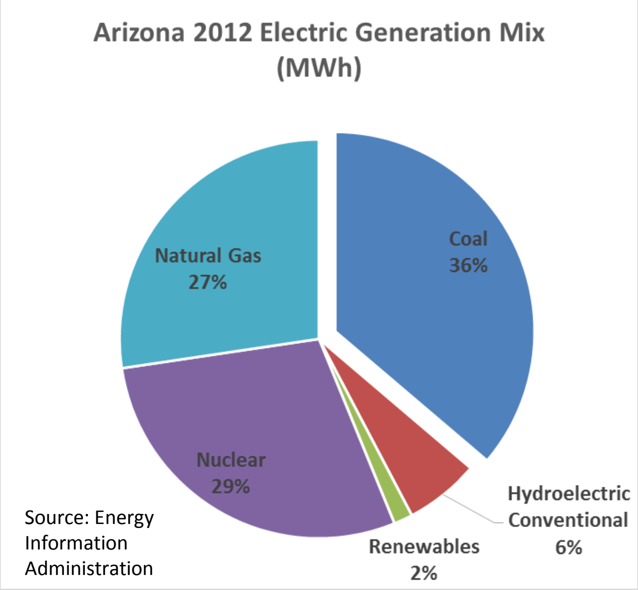
Estimated Clean Power Plan Impact on Arizona

Arizona's G&T Cooperatives
Touchstone Energy® Cooperatives

- Arizona was one of the states hit hardest by EPA's 111(d) proposal, the result of which would be the shut down of all of the state's non-tribal coal generation by 2020 stranding **$3.8 billion in assets** (Pace Global Study, 2020 dollars).

- The Arizona Department of Environmental Quality demonstrated in its filed comments that Arizona does not have the flexibility necessary to comply with the rule's targets except via direct application of the Building Blocks as the EPA proposed.

- If the EPA's proposal is left unmodified, the following are anticipated outcomes for the state's energy future.
  - Electric rates will rise significantly as a result of the loss of the state's coal plants, a cheaper generation source than natural gas.[1]
  - Arizona will go from a net exporter of power to a net importer within the next decade, and will be forced to rely upon its neighbors in order to serve its peak summer demand.
  - Electric reliability in the region will suffer until remedies can be effected.
  - With a heavy dependency on natural gas, the state's electric customers would become captive consumers to natural gas price



[1] Natural gas fuel cost is estimated at 50-100% more expensive than coal over the next 10 years, but is highly volatile.

EPA's Building Blocks (BB) Implications on AEPCO

BB1: Efficiency Improvements

- AEPCO has identified roughly 1 to 1.5% in available heat rate improvements with a reasonable payback schedule, assuming that coal units were preserved beyond 2020. This is well below the EPA's assumed level of 6%. Planned regional haze and MATS investments are imprudent with 2020 end.

BB2: Re-dispatch to Natural Gas

- Although AEPCO has natural gas resources, they are not designed to be operated as primary load-following units, and the heat rates average from 11-14 MMBtu/MWh at best (compared to 10.6 MMBtu/MWh), resulting in extremely costly energy.
- Load following units are required at Apache Generating Station to provide the area's grid reliability.

BB3: Use of Low or Zero-Emitting Sources

- AEPCO has contracts for roughly 30MW of hydro resources. Hydroelectric generation, under the proposed 111(d) rule, will not help in blending down AEPCO's CPP emission rate.
- The active generation required to supplement and back-up intermittent solar or wind generation, and the small size of AEPCO's fleet, make acquisition of these resources unattractive.

BB4: Energy Efficiency

- Due to the low population density and high transportation cost of resources, energy efficiency programs are extremely difficult to implement and highly uneconomical in rural communities.
- As a non-load serving entity, AEPCO has no opportunities for energy efficiency savings at the retail load level.

Options Studied

Arizona's G&T Cooperatives
Touchstone Energy® Cooperatives

- AEPCO evaluated three options:
  - **Base Case**: Convert ST2 and ST3 as required by RHR FIP/SIP in late 2017 and operate through 2035 pursuant to existing contracts.
  - **Compliance Option**: Purchase MW of an existing affected NGCC unit in 2015; convert ST2 to natural gas in 2017; retire ST3 in 2017; purchase MW NSPS compliant generation; and purchase solar PV and Wartsilas as needed to both achieve Interim and Final Goals and minimize additional costs.
  - **Exit Option**: Purchase MW of unaffected NGCC in 2015; convert ST2 to natural gas in 2017; retire ST3 in 2017; retire ST1 and ST2 in 2019; purchase MW new, NSPS NGCC starting 2020; purchase solar PV and Wartsilas as needed to achieve Interim and Final Goals and minimize additional costs.

Estimated Clean Power Plan Impact to AEPCO

Arizona's G&T Cooperatives
Touchstone Energy® Cooperatives

Analysis was performed to project the costs which AEPCO would incur in order to comply with the proposed rule. Two primary options were considered: one in which AEPCO attempts to keep existing generating units, and another where the CPP-affected units are replaced.

Shown below is the additional cost for these options (above AEPCO's current debt), as well as the resulting position of AEPCO relative to the electric pricing of the Arizona market. It is anticipated that AEPCO cannot survive if its pricing is higher than market.

Scenario:	AEPCO Compliance Option	AEPCO Exit Option
Description	Attempt to Remain in 111(d) program by retiring Coal and blending down Natural Gas emission rate on remaining units with Solar.	Retire all affected units in 111(d) program. Purchase New-Build assets to replace lost capacity.
Additional Cost (% Increase from Current Debt) [1]	**$580M (312% Debt Increase)**	**$418M (225% Debt Increase)**
Total Cost of Electric Service vs. AZ Market	**38.5% over Market**	**37.6% over Market**

[1] The Additional Cost for these options is in addition to AEPCO's current debt of **$186M**.

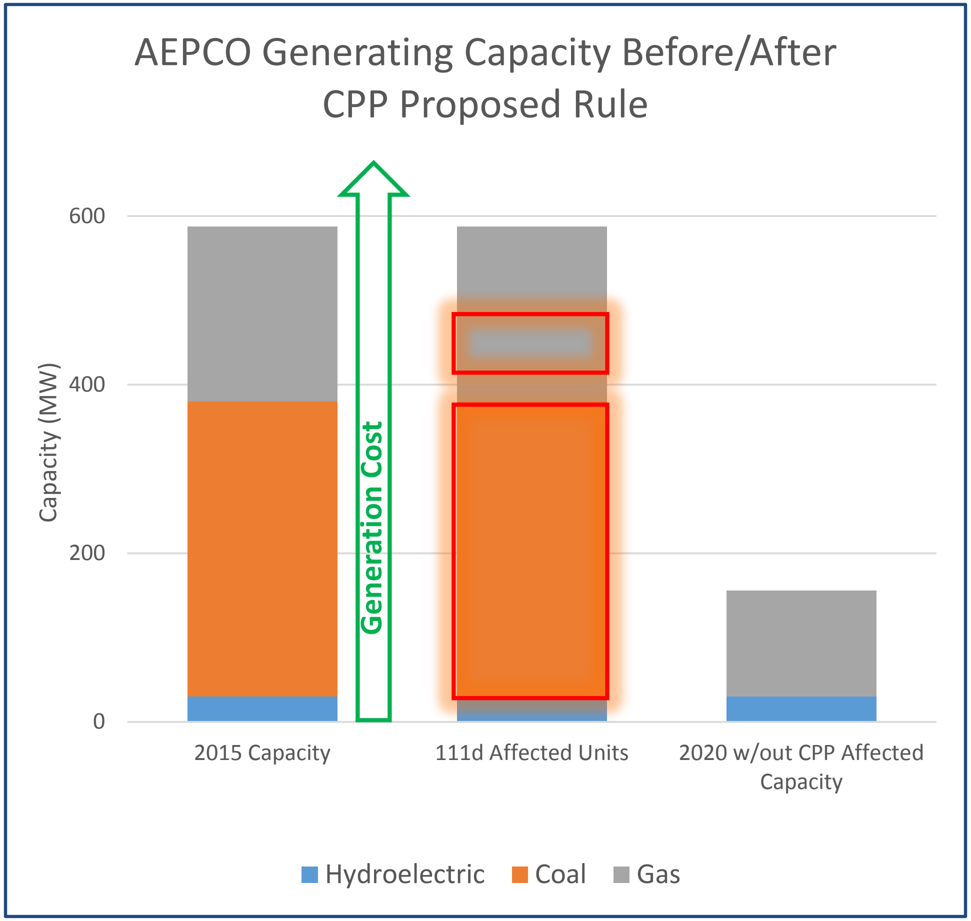
Impact on AEPCO

Arizona's G&T Cooperatives
Touchstone Energy® Cooperatives

- Unless changes, it appears that Interim Goal and Final goal will require shut down of Apache Station in 2020.
- Even with changes in Interim Goal, AEPCO has no realistic way of reaching the Final Goal by 2030.
- This jeopardizes 425 MW of 555 MW capacity.
  - Creates reliability issues on transmission system

Proposed 111(d) Impact on AEPCO

- If the aggressive AZ targets of the proposed 111(d) rule were imposed on AEPCO, over 90% of AEPCO's most affordable capacity, which is 75% of AEPCO's total capacity, would become stranded.
- Replacing the stranded capacity is expected to at least triple AEPCO's existing debt, which AEPCO believes not to be sustainable.
- Both AEPCO and the State of Arizona require a rational and reasonable plan to achieve CO2 reductions without compromising the affordability and reliability of the Arizona electric system.



Impact on AEPCO

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- Closure of ST2 and ST3 provide substantial capacity and economic energy reliability to the southeast Arizona system.
- AEPCO would be unable to maintain voltage in the Southeast Arizona quadrant (the "southern bubble") that is currently anchored by Apache Station.
- Inadequate time for construction of transmission and gas system infrastructure.
- Additional sources of generation would be required for AEPCO's transmission network in the "southern bubble."

Financial Impact on AEPCO

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- The premature retirement of AT2 and ST3 will cost AEPCO upwards of $400 million to replace.
  - More than triples existing debt
  - Forcing rural and financially limited customers to pay for unused electric generation facilities
- ST2 and ST3 represent 75% of AEPCO's $185 million debt

Solutions

- EPA should subcategorize the affected EGU category to provide a pathway for small public and cooperative utilities to achieve substantial reductions, but over a longer time frame consistent with their financial abilities.
- Who:
  - Public and cooperative utilities with base year sales of 4 million megawatt hours or less
  - Disproportionately affected by proposed Clean Power Plan

Who Qualifies

- In order to qualify for relief, the small public or cooperative utility would need to demonstrate, applying EPA's building blocks only to its existing system resources, that:
  - One or more affected EGUs (a "non-achieving unit") cannot meet the relevant state Interim Goal or Final Goal; AND
  - Such non-achieving unit(s) make up 20% or more of the small public or cooperative utility's generating capacity; AND
  - Shutting down the unit in 2020 (or 2030) would occur prior to the end of the unit's remaining useful life; AND
  - The cost of building a replacement, NSPS-compliant unit together with the cost of paying down debt on the existing non-achieving units, would be excessive.

Alternative Guideline

- Interim Goal Period:
  - Achieve all reasonably cost effective heat rate improvements on any non-achieving unit(s) (not just coal-fired ones);
  - Redispatch any NGCC units it owns and operates until 70% annual capacity is achieved (offer for dispatch any not operated);
  - Install renewable energy or obtain RECs equal to 10% of the non-achieving unit(s) capacity within 5 years or plan approval or 2025, whichever is earlier;
  - Meet one-half of the general state plan energy efficiency goal, if the small public or cooperative utility has local distribution; and
  - Achieve reductions equal to the lesser of the state Final Goal or 15% of total carbon emissions across the small public or cooperative utility's portfolio by 2030, with at least 33% of that reduction to occur by 2020 or within three years of plan approval, whichever is earlier.

Alternative Guideline

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- Final Goal Period:
  - Shutdown the non-achieving unit(s) at the start of the final goal period; OR
  - If any non-achieving unit(s) will remain in operation beyond 2029, then
    - continue any measures imposed on the non-achieving unit(s) and the utility by the state plan effective in 2029; AND
    - install additional renewable energy or obtain renewable energy credits (in a state plan recognizing such credits) equal to at least 10% of the non-achieving unit(s)' capacity prior to the start of the final goal period and every five years thereafter if the unit(s) continue to run.
- In addition, <u>all units covered by alternative must shut down at the earlier of the end of their remaining useful life or December 31, 2039, as specified in state plan.</u>

Impact of Alternative

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Market Price Forecast (ACES)	Peak Rate	Wrap Rate		Comments
High Price, $/MWh				
Low Price, $/MWh				
AEPCO/PPA Cost Comparison	PPA	AEPCO Compliance	AEPCO Exit	Small Coop Proposal
Fixed Charge, $/KW-Month				
O&M Charge, $/KW-Month				
Capacity Charge, $/KW-Month				
Capacity Charge, $/MWh				
Variable O&M Charge, $/MWh				
Energy Charge, $/MWh				
Total Cost, $/MWh	Base	38.5% over base	37.6% over base	8.3% over base

Impact of Alternative

- AEPCO has evaluated the potential impact of its proposed subcategory on EPA's Clean Power Plan proposal.
  - EPA is guaranteed at least 15% reduction or State Goal achievement by all small public and cooperative utilities.
  - It will likely be more: In AEPCO's case, it results in a 21% overall portfolio decrease

Impact on CO_2 Reductions

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- AEPCO assessed the preliminary impact on carbon reductions.
  - Unclear if all small entities qualify
  - Maximum leakage is 9 million metric tons (1.2%)
  - Likely leakage is 6 million metric tons (0.8%)
- However, alternative requires improvements on total portfolio, further reducing leakage from proposed Clean Power Plan.

Arizona Utility Group (AUG) Solution

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- EPA should account for "remaining useful life" of coal-fired power plants in establishing interim and final goals (similar to "book life" concept in Notice of Data Availability) and adjust Building Block #2 re-dispatch schedule as follows:
  - Default re-dispatch date for all units is 40 years after startup date, or 2020, whichever is later
  - For EGUs that have installed a major pollution control retrofit (SCR, FGD, or baghouses)* prior to issuance of the final 111(d) rule, default re-dispatch date is 20 years after start of operation following addition of the major pollution control retrofit, or 2020, whichever is later
  - For EGUs that have been issued a permit incorporating a commitment to cease burning coal before the effective date of the final rule, re-dispatch date is the date of the commitment
- Allow states to set interim goals
- Apply appropriate natural gas emission rate (1000 lb/MWh)

* For units owned by small entities as defined by FERC, a major pollution control retrofit would include equipment such as SNCR and ESP and would have to be installed prior to first year of compliance period (i.e., 2020)

Estimated Nationwide Impact

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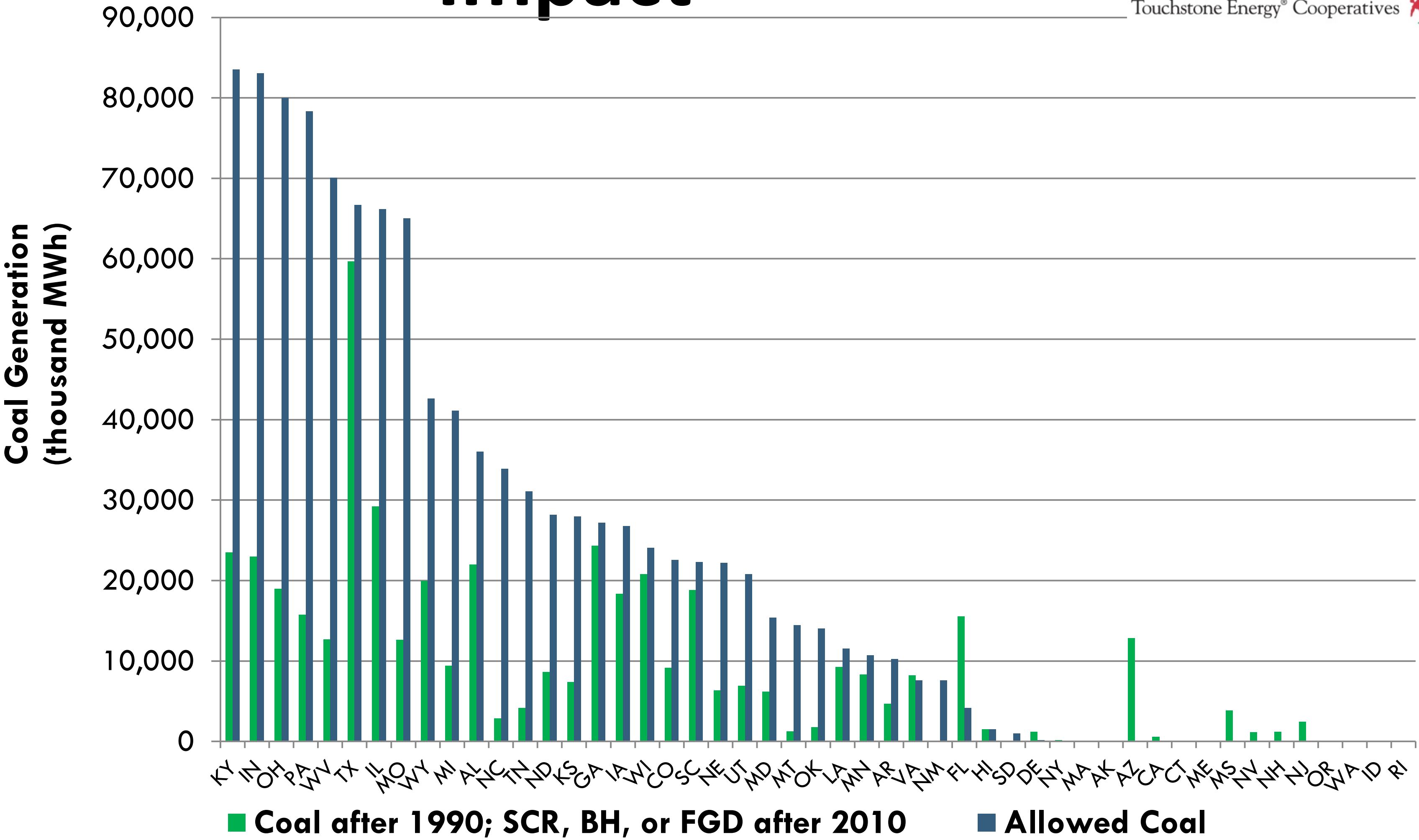

AUG Solution Impacts

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Exhibit 3: Summary of Cost Impacts of the Clean Power Plan (2013$)

	AZ Glide Path Scenario	EPA Building Block Scenario	Delta (EPA BB – AZ Glide Path)	Percent Change
2020-2030 Average Fuel + PP Costs ***($/MWh)***	$37.9/MWh	$52.7/MWh	$15/MWh	40%
2020-2030 Total Fuel + PP Costs ***($Billion)***	$44.5B	$62.2B	$17.7B	40%
2020 – 2030 Gas Capacity (MW)	7,825MW	10,125MW	2,300MW	29%
2020-2030 Capital Cost Investment ***($Billion)***	$6.2B	$8.1B	$1.9B	31%
Stranded Cost in 2020 Due to Early Coal Closures ***($Billion)***	n/a	$3.04B	n/a	n/a

Note that the additional cost associated with new and upgraded electric transmission and natural gas pipeline infrastructure required to meet Clean Power Plan goals are not included in this summary.

AUG Final Goal: **942 to 963** lb/MWh, a 34 to 35% reduction

Summary

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- CPP as proposed imposes substantial burdens on AEPCO, likely resulting in shut down of Apache Station or excessive costs on relatively poor, few and rural rate payers of members
- Subcategorization can significantly reduce the burden by allowing time to achieve EPA's goals at substantially less cost
- AUG solution achieves similar reduction; two can work in tandem
- Relief on timing and goals is needed to preserve rural electric service in AEPCO service area