SALT RIVER PROJECT COMMENTS ON
EPA’S PROPOSED EMISSION GUIDELINES FOR
EXISTING ELECTRIC GENERATING UNITS
EPA-HQ-OAR-2013-0602

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## Acronyms

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<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>ACC</td>
<td>Arizona Corporation Commission</td>
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<tr>
<td>ADEQ</td>
<td>Arizona Department of Environmental Quality</td>
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<td>APS</td>
<td>Arizona Public Service</td>
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<td>ASU</td>
<td>Arizona State University</td>
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<td>AUG</td>
<td>Arizona Utilities Group</td>
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<tr>
<td>BART</td>
<td>Best Available Retrofit Technology</td>
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<td>BLM</td>
<td>Bureau of Land Management</td>
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<td>BSER</td>
<td>Best System of Emissions Reduction</td>
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<tr>
<td>Btu/kWh</td>
<td>British thermal units per kilowatt-hour</td>
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<td>CAA</td>
<td>Clean Air Act</td>
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<td>Clean Air Scientific Advisory Committee</td>
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<td>CC</td>
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<td>CEQ</td>
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<td>Coronado Generating Station</td>
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<td>CICS</td>
<td>Coalition for Innovative Climate Solutions</td>
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<td>CO₂</td>
<td>carbon dioxide</td>
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<td>DOE</td>
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<td>dth</td>
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<tr>
<td>EM&amp;V</td>
<td>evaluation, measurement, and verification</td>
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<td>EPA</td>
<td>U.S. Environmental Protection Agency</td>
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<td>EPRI</td>
<td>Electric Power Research Institute</td>
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<tr>
<td>ESP</td>
<td>electrostatic precipitator</td>
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<td>FCPP</td>
<td>Four Corners Power Plant</td>
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<td>FEIS</td>
<td>Federal Environmental Impact Statement</td>
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<tr>
<td>FTE</td>
<td>full-time equivalent</td>
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<td>GHG</td>
<td>greenhouse gas</td>
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<td>gigawatts</td>
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<tr>
<td>ICF</td>
<td>ICF International</td>
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<tr>
<td>IGCC</td>
<td>integrated gasification combined cycle</td>
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<td>IPM</td>
<td>Integrated Planning Model</td>
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<tr>
<td>IRP</td>
<td>Integrated Resource Plan</td>
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<tr>
<td>lb CO₂/MWh</td>
<td>pounds of carbon dioxide per megawatt-hour</td>
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<tr>
<td>MMBtu/hr</td>
<td>million British thermal units per hour</td>
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<tr>
<td>MW</td>
<td>megawatt</td>
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<tr>
<td>MWh</td>
<td>megawatt-hour</td>
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<tr>
<td>NAAQS</td>
<td>National Ambient Air Quality Standards</td>
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<tr>
<td>NEPA</td>
<td>National Environmental Policy Act</td>
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<tr>
<td>NERC</td>
<td>North American Electric Reliability Corporation</td>
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<td>NGCC</td>
<td>natural gas combined cycle</td>
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<td>NGS</td>
<td>Navajo Generating Station</td>
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<td>NODA</td>
<td>Notice of Data Availability</td>
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<td>NREL</td>
<td>National Renewable Energy Laboratory</td>
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<td>NSR</td>
<td>New Source Review</td>
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<td>OG</td>
<td>oil/gas</td>
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<tr>
<td>ppb</td>
<td>parts per billion</td>
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<tr>
<td>PRB</td>
<td>Powder River Basin</td>
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<tr>
<td>PSC</td>
<td>public service commission</td>
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<td>PVNGS</td>
<td>Palo Verde Nuclear Generating Station</td>
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<tr>
<td>RE</td>
<td>renewable energy</td>
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<td>renewable energy credit</td>
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<td>Regional Economic Models Inc.</td>
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<td>RIA</td>
<td>Risk Impact Analysis</td>
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<td>RGA</td>
<td>recognized governing authority</td>
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<td>RPS</td>
<td>renewable portfolio standard</td>
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<td>RRTT</td>
<td>Rapid Response Team for Transmission</td>
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<td>S&amp;L</td>
<td>Sargent &amp; Lundy</td>
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<tr>
<td>SCR</td>
<td>selective catalytic reduction</td>
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<tr>
<td>SGS</td>
<td>Springerville Generating Station</td>
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<tr>
<td>SNCR</td>
<td>selective non-catalytic reduction</td>
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<td>SPP</td>
<td>Sustainable Portfolio Principles</td>
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<td>SRP</td>
<td>Salt River Project Agricultural Improvement and Power District</td>
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<tr>
<td>TEP</td>
<td>Tucson Electric Power</td>
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<tr>
<td>UARG</td>
<td>Utility Air Regulatory Group</td>
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<tr>
<td>UCS</td>
<td>Union of Concerned Scientists</td>
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<tr>
<td>Acronym</td>
<td>Description</td>
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<tr>
<td>UMP</td>
<td>Uniform Methods Project</td>
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<tr>
<td>WECC</td>
<td>Western Electricity Coordinating Council</td>
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<tr>
<td>WEPCO</td>
<td>Wisconsin Electric Power Company</td>
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<tr>
<td>WESTAR</td>
<td>Western States Air Resources Council</td>
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1. EXECUTIVE SUMMARY

On June 18, 2014, the U.S. Environmental Protection Agency (EPA or Agency) issued a Proposed Rule that would establish enforceable guidelines for states to follow to reduce greenhouse gas (GHG) emissions, specifically carbon dioxide (CO\(_2\)) emissions, from existing fossil-fuel-fired electric generating units (EGU) under Section 111(d) of the Clean Air Act (CAA).\(^1\) EPA states that the proposal, entitled the “Clean Power Plan,” would maintain an affordable, reliable energy system, while cutting CO\(_2\) emissions from the electricity sector by 30% from 2005 levels by 2030. Subsequent to the release of the Proposed Rule, EPA issued a Notice of Data Availability (NODA) to provide additional information on several topics raised by stakeholders during discussions held with EPA staff regarding the content of the Proposed Rule.\(^2\)

Salt River Project Agricultural Improvement and Power District (SRP) is a political subdivision of the State of Arizona that provides retail electric services to approximately 1 million residential, commercial, industrial, agricultural, and mining customers in Arizona. As a vertically integrated utility, SRP provides generation, transmission and distribution services, as well as metering and billing services. SRP relies on an intentional and beneficial diverse portfolio of owned and purchased generation resources that includes coal, natural gas, hydroelectric, nuclear, solar, wind, biomass, and geothermal. From a fossil fuel-fired electric generation perspective, SRP has ownership interests in six coal-fired power plants located in Arizona, New Mexico, and Colorado, and five natural gas-fired power plants located in central Arizona. SRP operates two of the coal-fired plants and all of the natural gas-fired plants. Given SRP’s ownership and operating interests related to fossil fuel-fired electric generation, SRP has a clear and significant interest in this pending action.

Prior to EPA’s proposal, SRP already had taken significant and material action to reduce its carbon emissions intensity. For example, in 2004, SRP’s publicly-elected Board of Directors (SRP Board) directed SRP to enhance its resource portfolio by adding significant amounts of renewable energy (RE) and other sustainable resources through the development of “Sustainable Portfolio Principles” (SPP). The SPP has matured and intensified over the years and the most recent revision to the SPP, approved by SRP’s Board in 2011, requires SRP to meet 20% of SRP’s expected retail energy requirements with sustainable (zero-carbon) resources by 2020. SRP has already reduced system-wide carbon intensity by 18% from Fiscal Year (FY) 2006 through FY2012 and has been working to further enhance this performance. The current plan is

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\(^1\) Carbon Pollution Emission Guidelines for Existing Stationary Sources, 79 Fed. Reg. 34,830 (proposed June 18, 2014) (Proposed Rule).

\(^2\) Notice of Data Availability, 79 Fed. Reg. 64,543 (October 30, 2014).
to achieve an additional 34% reduction by FY2031 while managing the economic impact to customers and protecting grid reliability.

SRP’s overarching concern with EPA’s current proposal is that it reaches far beyond the Agency’s regulatory authority in determining the best system of emissions reduction (BSER) and proposing emissions guidelines. By establishing federally enforceable interim and final state emissions reductions mandates in the manner set out in the Proposed Rule, EPA has usurped the state’s role under section 111(d), which is to establish the performance standards for existing sources, and has impinged on regulatory authority expressly left to state, municipal, or other local bodies, including SRP’s Board. Such “an enormous and transformative expansion in EPA regulatory authority without congressional authorization” certainly could not have been contemplated when section 111(d) of the CAA was enacted.\(^3\)

For Arizona, the proposed interim and final goals place an inequitable burden on the state to achieve CO\(_2\) reductions. EPA’s proposed final goal for Arizona would require a 52% reduction in CO\(_2\) emissions intensity from the proposed program baseline year of 2012. Even more problematic is EPA’s proposed interim goal for Arizona, which would require Arizona to achieve 90% of the total reductions required by EPA as early as 2020, the first year of the 10-year interim goal period.\(^4\)

In addition to the comments provided in this document, SRP supports and incorporates by reference those comments filed by organizations of which SRP is a member, including the Coalition for Innovative Climate Solutions (CICS), the Utility Air Regulatory Group (UARG), the Arizona Utilities Group (AUG), the American Public Power Association (APPA), the Large Public Power Council (LPPC), Western Energy Supply and Transmission Associates (WEST Associates), and the Electric Power Research Institute (EPRI).

1.1 Recommended Solutions to Critical Concerns with EPA’s Proposed Rule

Notwithstanding SRP’s significant concerns with the legality of the proposal, SRP believes there are solutions available to moderate the impact of the rule on Arizona while still achieving meaningful reductions in carbon emissions intensity. If EPA moves forward with implementing the proposed solutions to address the interim and final goals described below, the impact to SRP’s customers would be approximately $2.4 billion less than if SRP were forced to implement the rule as proposed by EPA. Beyond these significant cost savings, it is important for EPA to support a rational path for carbon reductions that fully accounts for the complex structure of

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the country’s current electric generation and transmission grid, natural gas supply network, and
the recent infrastructure investments mandated by EPA through other CAA regulations.

(a) Allow Arizona to Determine its Path to the 2030 Goal
The most appropriate solution to address the constraints imposed by the interim goal currently
proposed for Arizona is for EPA, as contemplated and directed by Congress, to give Arizona the
latitude to define and track its own progress towards the state’s final emissions rate goal.
Rather than mandating enforceable interim goals, EPA should give states discretion to develop
individualized plans for the 2020-2029 time period that set a state on a compliance path to
meet their 2030 emission goals. In particular, EPA should allow each state to make its own
determination as to which measures can be implemented on a time table that is manageable
for the state, but leads to achievement of the 2030 goals. SRP recommends that EPA base its
approval on procedural criteria that would ensure that the plans are both credible and
enforceable, and substantive criteria that would ensure that the plans consider factors
important to controlling CO₂ emissions. The criteria, which should be clearly defined by EPA,
would serve as the basis for an inquiry into whether a state plan adequately demonstrates that
it will lead to compliance with the state’s 2030 goal.

(b) Accommodate Remaining Useful Life
SRP urges EPA to allow Arizona to consider remaining useful life in developing the state’s
emission reduction plan to avoid early retirement of coal-fired EGUs with significant remaining
asset value. Specifically, EPA should adjust the assumptions made under Building Block 2
consistent with a recommendation developed by the AUG. The AUG proposal includes a few
targeted changes to the Building Block 2 calculation that would result in a final rule that: (1)
does not threaten electric reliability; (2) still obtains substantial reductions in carbon emissions
intensity both in Arizona and nationwide; and (3) would be substantially more cost-effective
and attuned to the statutorily-mandated “remaining useful life” concept. These changes
include the following:

- Redispatch from coal-fired EGUs to natural gas combined cycle (NGCC) EGUs should
  occur upon the later of any of the following, if redispatch would occur prior to January
  1, 2030:
    - January 1, 2020;
    - January 1 of the year following 40 years after initial commencement of
      operation; or
    - January 1 of the year following 20 years after commencement of operation of
significant air pollution controls\textsuperscript{5} at any EGU if installation occurred prior to issuance of the final 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).

- 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.

- Coal-fired EGUs that do not redispatch prior to January 1, 2030 remain coal-fired EGUs for purposes of calculating the interim and final goals.

Implementation of these reasonable changes, which are consistent with the concepts introduced in the NODA, would address SRP’s significant concerns about the stranded costs associated with prematurely retiring coal-fired units with significant remaining useful life.

This is a particularly critical issue for SRP. SRP owns Units 1 and 2 at the Coronado Generating Station (CGS). As of October 31, 2014, the net book value of CGS is $630 million. The majority of that book value is attributable to air pollution control equipment upgrades on Units 1 and 2 that were completed between 2009 and 2014, which cost approximately $470 million. The bond financings for this project were approximately 30 years with the final bond maturity occurring in 2041. In addition, EPA established emission control requirements based on an assumed remaining useful life of 20 years, which presumed that CGS would continue to operate beyond 2030.

SRP also owns one of the four units currently active at Springerville Generating Station (SGS), Unit 4, which came on line in December 2009 at a cost of $1 billion. The current net book value for SGS Unit 4 is $900 million. It likewise has bond financing for approximately 30 years with final bond maturity occurring in 2038. EPA acknowledges that the useful life of a coal-fired unit operating to meet base load demand is 40 years.\textsuperscript{6} Accordingly, EPA should expect that SGS Unit

\textsuperscript{5} Significant air pollution control equipment includes selective catalytic reduction systems, baghouses, or flue gas desulfurization systems.

4 would remain operating as a baseload facility until at least 2049 for the purpose of establishing the goals. SRP also has a 30-year power purchase agreement to purchase power from SGS Unit 3, which came on line in 2006 at a cost of $939 million, with the anticipation that this unit, which is nearly identical to Unit 4, also would have a useful life of 40 years.

SRP’s investments in these facilities to date are substantial. Prematurely retiring Arizona coal generation will place an unreasonable burden on electricity customers who must now cover the stranded costs of these assets, as well as the cost of building new infrastructure required to replace this generation. By adopting the reasonable and straightforward changes described above, EPA would provide a more rational path to resource transition, protect reliability, and reduce the economic burden of the rule on Arizona’s electricity customers.

(c) Solutions to Address Compliance Flexibility
Approximately 47% of SRP’s renewable generation is from out-of-state resources. It is imperative that EPA clearly identify in the guidelines to states in the final rule that affected sources have the ability to include out-of-state renewable resources in compliance plans. The ability to invest in renewable resources, both in-state and out-of-state, allows utilities to engage in more cost-effective development of these resources and promotes greater diversity of resource portfolios.

While some parties commenting on this proposal have expressed a concern that RE attributes could be double-counted by being claimed in multiple state plans, SRP is confident that states can avoid this issue through adoption of systems that create and track the use of renewable energy credits (REC), such as the Western Renewable Energy Generation Information System (WREGIS). Using REC systems, such as WREGIS, would greatly expand RE procurement options for all participants. States would gain access to RE that could be used for compliance regardless of its deliverability. Participants with larger compliance obligations could purchase RECs from out-of-state RE projects that are more competitively priced than those that might be built in state. Likewise, states with an abundance of RE projects beyond their compliance obligations could benefit by selling RECs to others. To the extent possible, SRP encourages EPA to provide states support in using RE accounting systems to fully realize available RE procurement options.

Similarly, SRP encourages EPA to promote full recognition of existing energy efficiency (EE) programs and practices in state compliance plans. SRP further encourages EPA to establish an easy, straightforward, and timely method states can use to modify existing EE programs and add new programs to its state plan without relying on EPA approval of these programs before they can be implemented. Also, EPA must allow states to determine appropriate levels of evaluation, measurement, and verification (EM&V) for specific programs and measures included in the state’s compliance plan while utilizing industry established EM&V best practices.
and protocols per EPA guidance. Finally, as contemplated in the NODA, SRP supports EPA’s provision of a mechanism for states to obtain credit for early-action as it pertains to EE program development and implementation prior to the rule implementation date.

(d) Other Recommended Actions to Address Technical Concerns with EPA Goal Calculations

In addition to the recommended solutions identified above, SRP also strongly urges EPA to consider and adopt the following methodology changes to the state goal calculations:

- **Revise the natural gas emission rate.** EPA should use an emission rate for NGCC units that is no lower than the rate proposed for new sources under section 111(b).

- **Use summer net dependable capacity.** Nameplate capacity is not an appropriate measure of actual NGCC capacity in general or capacity that is available year-round. EPA should use summer net dependable capacity, as reported to the North American Electric Reliability Corporation (NERC) for analysis of system reliability, in calculation of available existing NGCC capacity available for use under Building Block 2.

- **Remove the “at-risk” factor for nuclear generation that is not at risk.** Instead of applying a generic “at-risk” factor to all existing nuclear generation, EPA should apply a site-specific “at-risk” factor where nuclear generation is really at risk. With the current approach, EPA is diluting impacts where nuclear generation is actually at risk and creating issues where it is not at risk, such as in Arizona.

- **Establish an appropriate baseline period.** EPA must start with a baseline period that is representative of actual generation and CO₂ emission levels. SRP supports the use of alternative multi-year baseline periods to minimize the impact of anomalies that were present in 2012. At a minimum, EPA should address certain anomalies in 2012 data that unfairly penalize some states or companies.

- **Moderate assumptions related to unit efficiency improvements.** EPA has not adequately demonstrated that individual existing EGUs can realize a 6% improvement in efficiency as assumed by EPA in calculation of Building Block 1 reductions. Given that heat rate improvements are dependent on the characteristics of the individual unit, state-specific data should be used to estimate potential heat rate improvements rather than using a national average for all units.

- **Establish appropriate energy efficiency savings values in goal setting.** EPA must take available research, such as that performed by the Electric Power Research Institute,
under advisement when establishing energy efficiency savings values for use in the goal setting calculations.

1.2 Concerns Regarding EPA’s Reliability and Cost Modeling Analysis

To assess the reliability and cost implications of the Proposed Rule, EPA conducted an analysis using the Integrated Planning Model (IPM). SRP retained The Brattle Group (Brattle) to conduct a detailed review of EPA’s analysis. The review focused on the “Base Case” (without implementation of the Proposed Rule) and “Option 1” (assuming each state meets its individual CO₂ goals without a regional compliance plan). Brattle found several flaws in EPA’s analysis that SRP believes have led to EPA’s underestimation of the reliability and cost impacts of the Proposed Rule. SRP is particularly concerned about EPA’s analysis with respect to electricity imports, power plant ownership, and energy efficiency.

EPA’s reliability analysis predicts that Arizona would shift from its current status as a net exporter of electricity and would import significant quantities of generation to meet Arizona’s proposed interim and final goals. It is unrealistic to assume that Arizona would (or could) rely so significantly on out-of-state power to meet demand, particularly peak demand, due to the uncertainty as to whether these resources are available at the time they are needed. Other concerns also arise from EPA’s assumption that Arizona would shift to reliance on imported electricity. Most notably, EPA has not performed the required studies or conducted reviews of existing transmission rights, reservations, or resource ownership and purchase agreements, to demonstrate that this significant shift in power flow would even be possible as EPA envisions, as the IPM does not consider these constraints. In fact, the Arizona Corporation Commission’s (ACC) Integrated Resource Plan (IRP) rules state that utilities cannot rely on capacity that is not sourced from known generation for reserve margin requirements.⁷

Given the uncertainties associated with Arizona’s ability to meet the state’s proposed intensity goals, SRP believes there is a real possibility for reliability to be compromised, particularly in the early years of the program when EPA envisions that massive coal plant curtailments and retirements coupled with a reliance on market purchases would be necessary to meet Arizona’s interim goal. In addition to incorporating the solutions discussed above, SRP believes EPA should consider adding a provision that would give affected sources a regulatory “safety valve” in the event sources scheduled to be curtailed or retired under compliance plans must continue to run to support electric system reliability.

1.3 Concerns Regarding EPA’s Legal Approach to Regulation of Existing EGUs

Notwithstanding SRP’s comments regarding ways EPA can modify the current proposal to support a more reasonable path to reduce GHG emissions, SRP fundamentally believes that EPA has failed to provide an adequate legal basis for moving forward with regulation of existing EGUs under CAA section 111(d). Most importantly, EPA’s proposal violates a host of federal, state, and local laws governing the electric utility industry by seeking to step into matters not only reserved to a sister federal agency – FERC – but also into matters expressly left to the control of state, municipal, or other local government authorities, such as SRP’s publicly-elected Board of Directors.

Furthermore, because EPA previously chose to regulate emissions from existing coal-fired EGUs under section 112, the CAA unambiguously provides that the Agency is prohibited from also regulating these sources under section 111(d). Even if this prohibition could be overcome by EPA, the Agency must recognize that a fundamental element of section 111(d) is that states are expressly provided flexibility to develop performance standards that best address state-specific factors. Thus, while EPA may require states to submit plans that contain performance standards, EPA may not dictate the form and content of those standards, unless a state fails to submit an acceptable plan. And yet that is precisely what EPA has done in the Proposed Rule by establishing enforceable interim and final reduction goals.

In establishing the proposed emission goals, EPA also inappropriately included Building Blocks 2 through 4. Only Building Block 1 falls within the scope of measures contemplated by section 111 and could be a foundation for legally defensible emission guidelines. Building Blocks 2 through 4, however, go far beyond the measures authorized under section 111 because they require emissions reductions from something other than a regulated source. Because this novel approach has no basis in the CAA, it clearly exceeds EPA’s authority.

Finally, EPA ignores the critical fact that once an existing source is modified or reconstructed, it ceases to be an existing source subject to section 111(d) and becomes a new source subject to 111(b). Under the CAA, a source is either “existing” or it is “new”; it cannot be both at the same time. Moreover, under its explicit terms, section 111(d) may not apply to sources subject to section 111(b). Therefore, EPA cannot subject units to both sections under the Proposed Rule.

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8 CAA § 111(d)(2)(A).
1.4 Concerns Regarding EPA’s Best System of Emissions Reduction Determination

In addition to the legal infirmities associated with EPA’s novel approach to BSER, SRP believes the EPA’s BSER determination is technically flawed. In Building Block 1, EPA focuses on reduction of the carbon intensity of generation at individual affected units through heat rate improvements. SRP is concerned that EPA has not adequately demonstrated that, for the units that will be subject to the Proposed Rule, further heat rate improvements totaling 6% at each unit can be achieved as assumed by EPA. More specifically, SRP commissioned Sargent & Lundy to evaluate the opportunities for heat rate improvements at its two coal-fired EGUs at CGS. The results of this study indicate there are no additional opportunities to improve heat rate through best practices and only 1% further heat rate improvement potential from equipment upgrades.

Of the four building blocks included in EPA’s BSER determination, Building Block 2 produces the most dramatic impact on the calculation of the interim and final goals for Arizona. This building block, which accounts for approximately 80% of the total reductions associated with the proposed goals for Arizona, assumes that Arizona would shift all coal and oil/gas (OG) steam generation to natural gas generation by 2020. EPA’s assumptions regarding application of Building Block 2 within Arizona do not consider the resources needed to meet peak demand, and do not recognize the significant constraints that make such a wholesale shift in the state’s current energy infrastructure infeasible.

SRP analysis indicates that if EPA proceeds with establishment of interim and final goals that would result in the retirement of all coal and OG steam generation, Arizona will need substantial new electric transmission and natural gas pipeline infrastructure to support baseload use of existing NGCC power plants. Arizona also will require additional NGCC resources to cover state electricity demand, especially during periods of peak load. EPA must provide adequate time to site, plan, design, permit, and construct these facilities. SRP is particularly concerned that the high proportion of federal, state, and tribal lands in Arizona—more than 80%—represents unique challenges to timely completion of new energy-related projects.  

With Building Block 3, EPA assumes states would expand the use of low- or zero-carbon generation. EPA’s approach of using a 2012 baseline and establishing a goal based on a presumed increase from that level penalizes states like Arizona that have acted to reduce GHG emission intensity through early investment in carbon-free generation, including RE and nuclear

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9 Specifically, more than 72% of the lands in Arizona are under federal and tribal control. Those lands present even more daunting challenges for siting and development than state-owned lands. See http://www.epa.gov/region9/fedfac/fedmap.html.
generation, by requiring these states to meet even more stringent interim and final performance standards. EPA can reduce the impact of 111(d) implementation by clearly stating in the guidelines to states in the final rule that affected sources have the ability to include out-of-state renewable resources in compliance plans.

In addition to the approach to RE used by EPA in setting the Building Block 3 portion of state goals featured in the Proposed Rule, EPA also developed an “Alternative RE Approach” that relies on the technical and market potential of new RE. SRP objects to EPA’s use of the Alternative RE Approach because it would have the effect of further increasing the stringency of Arizona’s goals thereby increasing the state’s burden to achieve compliance with a 111(d) plan. Specifically, the Alternative RE Approach includes an assumption that states can accelerate construction of new RE and these resources would be available to lower emissions intensity by 2020. Arizona’s ability to construct additional new RE by 2020 is subject to many of the same constraints identified for implementation of Building Block 2, including the need for sufficient electric transmission infrastructure.

With Building Block 4, EPA assumes states would increase the use of demand-side EE measures. SRP appreciates EPA’s recognition of Arizona’s leadership in implementation of EE and agrees that some EE measures are a viable means of managing energy consumption, which in turn helps reduce CO₂ emissions. However, EPA must consider the realistic constraints on EE in assessing how it should be accounted for in the state goals.

Aggressive codes and standards will diminish future savings potential and limit the number of measures that are cost-effective for the customer and the utility. EE savings values need to be set at achievable levels because energy savings will be more challenging to deliver over the next 15 years as markets mature and federal equipment standards erode potential creditable savings.

SRP encourages EPA to be inclusive in its approach to EE and allow utilities to include all existing programs and practices. EPA also must establish an easy, straightforward, and timely method states can use to modify existing EE programs and add new programs to their plans without relying on EPA approval of these programs before they can be implemented. Otherwise, adoption of new technologies, measures, and programs will be constrained and could result in a state’s inability to achieve the established savings values. This flexibility will be especially important as the existing EE programs are more fully subscribed in future years.

1.5 State Compliance Plan Development and Implementation
SRP is concerned EPA has not provided sufficient time for states to complete 111(d) compliance plans. Due to the complexity of EPA’s proposal, affected entities will have to collaborate closely
with state regulatory agencies in plan development and time will be needed to complete the extensive discussions necessary to clearly identify, to the satisfaction of EPA, the measures that will be included in Arizona’s compliance plan, as well as the timeline for implementation of those measures. This complexity is further increased for states that wish to collaborate in development of multi-state plans.

While SRP appreciates EPA’s provision of extension options to states for development of compliance options, SRP remains concerned that the options provided don’t fully address the constraints states will face in crafting plans to address the portfolio of compliance options that EPA has made available through the building block approach to BSER. States and affected entities also are caught by the fact that if they are granted extensions for plan submittal, there is no corresponding extension to the start of program compliance. If a state takes 3 years to submit a compliance plan, and EPA takes 1 year to approve this plan, the state will have only 6 months before the start of the interim goal compliance period, at which time states and affected entities must begin documentable progress towards the interim goal.

SRP also is concerned that EPA has not provided sufficient clarity on when the Agency would enforce a state plan or measures therein, or issue a federal plan. EPA needs to identify how it will handle situations where a state is not on track to meet its interim state goal (per the progress checks every 2 years), including identifying the steps EPA would require for the state to amend its plan. SRP also requests additional clarity as to the measures that EPA would include in a federal plan since EPA does not have jurisdiction to compel non-EGU entities to participate in an emissions reduction program applicable to EGUs, and EPA does not have jurisdiction over retail sales of electricity.

SRP supports EPA’s proposal to allow states to translate their proposed emissions rate goals into equivalent mass-based goals. However, SRP has concerns about both approaches that EPA suggested in the Technical Support Document, although SRP recognizes that EPA intended this guidance to be illustrative and non-binding. In the final rule, EPA must make clear what states must provide to EPA to ensure their formula for translating the rate-based goals to mass-based goals is approvable. This guidance should ensure that all actions that reduce CO₂ emissions are counted under a mass-based program, without regard to additionality or other concerns that are not at issue under rate-based plans. EPA’s methodology also should account for load growth and result in mass-based goals that are no more stringent than rate-based goals.

1.6 Conclusion
SRP appreciates the opportunity to provide comments regarding this proposed action. As demonstrated by its existing commitments to reduce carbon emissions intensity, SRP believes it is possible to accomplish meaningful reductions in the country’s carbon intensity. SRP is willing
to share in this effort, but this change must be undertaken in a manner that appropriately manages economic impacts and protects reliability for all electricity customers.
2. INTRODUCTION

On June 18, 2014, the U.S. Environmental Protection Agency (EPA or Agency) issued a Proposed Rule that would establish enforceable guidelines for states to follow to reduce greenhouse gas (GHG) emissions, specifically carbon dioxide (CO₂) emissions, from fossil-fuel-fired electric generating units (EGU) under Section 111(d) of the Clean Air Act (CAA). EPA states that the proposal, which EPA calls the “Clean Power Plan,” would maintain an affordable, reliable energy system, while cutting CO₂ emissions from the electricity sector by 30% from 2005 levels by 2030. Under the proposal, each state would be responsible for adopting and implementing measures to reduce CO₂ emissions within their geographical borders in order to meet the national CO₂ emission reduction goal.

In the Proposed Rule, EPA proposes to establish two federally-enforceable CO₂ emission rate goals for each state: (1) an “interim” 10-year average emission rate goal for the years 2020–2029; and (2) a final emission rate goal in 2030. EPA developed each state’s goals using a prescribed formula in which the Agency applies “building blocks” that reflect measures that reduce CO₂ emissions. EPA states these building blocks comprise the “Best System of Emissions Reduction” (BSER) for reducing emissions from existing EGUs. Each state’s goals are unique as EPA takes into account each state’s unique generation mix in applying the four building blocks.

For Arizona, EPA calculated Arizona’s 2012 baseline fossil-fuel generation emission rate at 1,551 pounds of CO₂ per megawatt-hour (lb CO₂/MWh). EPA then adjusted this baseline to include certain zero-carbon/renewable resources in place in Arizona in the baseline year. After this adjustment, Arizona’s 2012 baseline emission rate is 1,453 lb CO₂/MWh. As outlined in Table 2-1 on the following page, EPA then successively applied each of the four building blocks to the adjusted baseline emissions rate to establish the interim and final emission rate goals for Arizona. The state’s proposed interim emission rate goal is 735 lb CO₂/MWh, and the 2030 emission rate goal is 702 lb CO₂/MWh. The final emission rate goal represents a 52% reduction when compared to the 2012 adjusted baseline.

Subsequent to the release of the Proposed Rule, EPA issued a Notice of Data Availability (NODA) to provide additional information on several topics raised by stakeholders during discussions held with EPA staff regarding the content of the Proposed Rule.

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10 79 Fed. Reg. at 34,830.

11 Solar, wind, and biomass generation resources that were present in the state in 2012 are included in the baseline adjustment, but hydroelectric resources are not. The adjustment also includes 5.8% of the 2012 generation from Palo Verde Nuclear Generating Station.
Table 2-1. EPA’s Determination of Arizona’s 2030 Emission Rate Goal

<table>
<thead>
<tr>
<th>Building Block</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Building Block 1</td>
<td>Improve heat rate for coal-fired units by 6%.</td>
</tr>
<tr>
<td>1,453 → 1,394 lb CO₂/MWh</td>
<td></td>
</tr>
<tr>
<td>Building Block 2</td>
<td>Redispatch coal and oil/gas steam units by increasing existing natural gas combined cycle generation up to 70% capacity (53% for Arizona).</td>
</tr>
<tr>
<td>1,394 → 843 lb CO₂/MWh</td>
<td></td>
</tr>
<tr>
<td>Building Block 3</td>
<td>Avoid retirement of “at-risk” nuclear capacity and add new nuclear capacity. Increase renewable energy capacity to reflect regional averaging of renewable portfolio standards.</td>
</tr>
<tr>
<td>843 → 814 lb CO₂/MWh</td>
<td></td>
</tr>
<tr>
<td>Building Block 4</td>
<td>Increase demand-side energy efficiency improvements to achieve 1.5% annual savings.</td>
</tr>
<tr>
<td>814 → 702 lb CO₂/MWh</td>
<td></td>
</tr>
</tbody>
</table>

The three topic areas addressed by the NODA are: (1) the emission reduction trajectories created by the interim goal for 2020 to 2029; (2) alternate approaches to treatment of natural gas in Building Block 2 and treatment of renewable energy (RE) in Building Block 3; and (3) certain aspects of EPA’s methodology for calculating state emissions reduction goals.

Salt River Project Agricultural Improvement and Power District (SRP) is a political subdivision of the State of Arizona that provides retail electric services to approximately 1 million residential, commercial, industrial, agricultural, and mining customers in Arizona. As a vertically integrated utility, SRP provides generation, transmission and distribution services, as well as metering and billing services. SRP relies on an intentional and beneficial diverse portfolio of owned and purchased generation resources that includes coal, natural gas, hydroelectric, nuclear, solar, wind, biomass, and geothermal. From a fossil fuel-fired electric generation perspective, SRP has ownership interests in six coal-fired power plants located in Arizona, Colorado, and the Navajo Nation, and five natural gas-fired power plants located in central Arizona. SRP operates two of the coal-fired plants and all of the natural gas-fired plants. Given SRP’s ownership and operating interests related to fossil fuel-fired electric generation, SRP has a clear and significant interest in this pending action.

Prior to EPA’s proposal, SRP already had taken significant and material action to reduce its carbon emissions. For example, in 2004, SRP’s publicly-elected Board of Directors directed SRP to enhance its resource portfolio by adding significant amounts of RE and sustainable resources through the development of “Sustainable Portfolio Principles” (SPP). The SPP has matured over the years and the most recent revision to the SPP, approved by SRP’s Board in 2011, requires SRP to ensure that 20% of SRP’s expected retail energy requirements will be met with sustainable (zero-carbon) resources by 2020. This target includes the percentage of retail
energy requirements met with annual aggregate energy-efficiency savings, pricing measures, hydroelectric generation and other renewable generation, including that which is directly attributable to certain customers (such as rooftop solar and Community Solar).

The target for Fiscal Year (FY)\textsuperscript{12} 2014 was 11.75\% and increases 1.375\% per year until 20\% is reached in FY2020. SRP’s program includes an incentive for early or accelerated acquisition, by allowing the environmental attributes of sustainable resources to be banked and applied to future years or sold to reduce customer costs.

Due to its proactive actions, SRP is currently outperforming the SPP targets. In FY2014, 12.8\% of SRP’s retail requirements were met with sustainable resources and more than 25\% of the energy produced by SRP’s resources had no associated GHG emissions. SRP also exceeded its annual incremental energy efficiency target of 1.50\%, achieving 2.3\% in FY2014.

SRP has made great strides in incorporating a diverse set of renewable energy resources and energy efficiency measures into its resource portfolio. SRP has recently been working to further enhance the company’s commitment to carbon reductions through the development of a comprehensive Integrated Resource Plan (IRP). This collaborative process was initiated in early 2014 and has included stakeholder engagement to produce a resource planning path to support a reduction in the GHG intensity of SRP’s electric generation resources. As shown in Figure 2-1 on the following page, SRP has already reduced its system-wide carbon intensity by 18\% from FY2006 through FY2012, and plans to further reduce its system-wide carbon intensity by 34\% from FY2012 through FY2031.

SRP agrees that no single technology will suffice to meet carbon emissions reduction goals. As such, SRP’s IRP will include a diverse portfolio of existing and new technologies. To this end, SRP continues to invest in research to identify and encourage the development of technologies that will enhance future reductions. Since 2000, SRP has invested more than $50 million in research and development through the Electric Power Research Institute (EPRI) and local universities, a significant amount of which has been focused on energy efficiency, power plant efficiency improvements, renewable resources, and carbon capture and sequestration.

Furthermore, SRP continues to evaluate new and emerging technologies that could be beneficial to SRP’s generation portfolio. These technology assessments focus on helping SRP understand the economic feasibility of the respective technology, as well as risks associated with implementation.

\textsuperscript{12} SRP operates on a fiscal year of May 1 through April 30.
SRP provides detailed comments on the Proposed Rule and the NODA in the following sections of this document. SRP’s overarching concern is that EPA’s proposal reaches far beyond the Agency’s regulatory authority in determining BSER and proposing emissions guidelines. By setting federally enforceable interim and final state emissions reductions mandates, EPA has usurped the state’s role under section 111(d), which is to establish the performance standards for existing sources. In Arizona’s case, EPA has set interim and final goals that strip the state of any ability to pursue a flexible approach to CO₂ emissions reductions, and place the state in a position where utility customers will be forced to spend significantly more to achieve compliance than customers in neighboring states. SRP believes there are solutions available to address these issues that will moderate the impact of the rule on Arizona while still achieving meaningful reductions in carbon emissions intensity.

SRP believes it is possible to accomplish meaningful change to the country’s carbon intensity, but this change must be undertaken in a manner that appropriately manages economic impacts and protects reliability for all electricity customers.
3. PRIMARY ISSUES AND PROPOSED SOLUTIONS

While SRP has numerous concerns regarding the Proposed Rule, the concerns outlined in this section represent those issues that have the greatest impact on SRP’s operations. In addition to outlining the issues themselves, SRP suggests solutions that can resolve these issues in a manner that ensures EPA achieves reductions in carbon emissions intensity, while reducing the economic impacts of the rule and ensuring the continued reliability of the Arizona electric system.

3.1 EPA’s Proposed Interim and Final Goals for Arizona are Unreasonable and Inequitable

The proposed interim and final goals established by EPA for Arizona place an unreasonable and inequitable burden on the state to achieve CO₂ reductions. Particularly problematic for Arizona is EPA’s proposed interim goal. The Proposed Rule would require Arizona to achieve nearly 90% of the state’s 2030 goal by 2020 – more than any other state in the country. This is due primarily to EPA’s assumptions regarding the application of Building Block 2 to Arizona.

SRP understands that EPA views Building Block 2 as a relatively easy way to achieve reductions in carbon intensity early in the program. Where existing natural gas combined cycle (NGCC) generation is present and has a low annual capacity factor in 2012, EPA assumes states can easily shift generation from their higher emitting coal and oil generation to their lower emitting natural gas generation.

EPA calculated existing Arizona NGCC generation to be operating at an annual capacity factor of 27% in the 2012 baseline year. Due to this low capacity factor, EPA assumes that all existing coal and oil generation in the state can be replaced with existing NGCC generation by 2020. This assumption presumes that Arizona will achieve approximately 80% of its 2030 goal by 2020 from application of Building Block 2 alone¹³ – again more than any other state – and produces the emissions reduction trajectory for Arizona shown in Figure 3-1 on the following page. This trajectory, as proposed by EPA, is not achievable. If EPA does not change its Building Block 2 assumptions for Arizona, the Proposed Rule will create significant economic impacts within the state and strain the reliability of the state’s energy grid.

One problem with the Building Block 2 assumptions is that EPA bases a state’s redispachtaken potential on the average annual capacity factor, but does not account for peak capacity needs. As the Arizona Department of Environmental Quality (ADEQ) and the Arizona utilities previously

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¹³ Because EPA removes all coal-generation capacity from Arizona in its goal setting calculation, any reductions claimed by Building Block 1 in the calculation summaries would actually be achieved under Building Block 2. Therefore, the reduction from the 2012 baseline (i.e., 1,453 lb CO₂/MWh) to the rate after application of Building Block 2 (i.e., 843 lb CO₂/MWh) represents 81.2% of the total reductions required under EPA’s goal setting analysis.
explained to EPA in stakeholder meetings during the Proposed Rule’s comment period, Arizona has significant peak load and reserve margin demands in the summer months. During these peak periods, all of the existing available NGCC resources within Arizona are typically in use, along with all existing coal and oil/gas (OG) steam generation.

**Figure 3-1. Impact of EPA’s Proposed Standards in Arizona**

With all resources in use, there is no “extra” NGCC capacity that can be used to replace the portion of load being provided by existing coal and OG generation during these periods. EPA’s red dispatching approach removes approximately 3,800 megawatts (MW) of coal and OG steam generating capacity from Arizona’s power system – all of which is currently used to meet peak demand.

An additional constraint is that more than 5,000 MW (53%) of the existing NGCC capacity in Arizona is owned by independent power producers, and not by the load-serving utilities in the state. It is not valid to assume that this merchant capacity is available under a 111(d) program for red dispatch to solely serve Arizona load. Arizona’s load serving entities currently purchase some of the energy from these generators under long- and short-term purchase agreements, but there is no ability by the load serving entities, the state, or EPA to force merchant generators to continue these sales in the future. A neighboring state could purchase the output of the merchant Arizona NGCC units at any time and reduce capacity available for Arizona red dispatch. Given this uncertainty in availability of merchant resources to serve Arizona load, utilities, including SRP, will need to construct new NGCC plants to ensure adequate system
reliability during peak demand periods if existing coal and OG steam must be curtailed or retired under the 111(d) program. Furthermore, SRP has examined current infrastructure availability and believes new facilities will be needed to operate existing NGCC at the higher capacity factors assumed by EPA.

For example, two pipelines currently provide service to SRP’s gas plants. One of those pipelines is operated by El Paso Natural Gas Company and the other is operated by Transwestern Pipeline Company. These systems, shown in Figure 3-2, have limited excess capacity available and are nearly fully subscribed in the winter months. If SRP were to operate its existing NGCC at a 70% capacity factor in the winter months, SRP would need an additional 160,000 decatherms (dth) per day of natural gas from the pipeline system. Existing winter capacity available for contracting currently ranges between 0 to 50,000 dth per day, far less than required by SRP.

Figure 3-2. Arizona and New Mexico Regional Gas Transportation Pipelines

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14 SRP is aware that EPA modeling indicates that Arizona would rely heavily on imported capacity from other locations in the Western U.S. to replace curtailed or retired coal capacity. SRP comments regarding these modeling conclusions are detailed in Section 4 of these comments.
Given the breadth of the Proposed Rule, SRP and other Arizona utilities will need to compete for natural gas supply for NGCC generation with shippers from California, New Mexico, and Texas. Furthermore, recent increases in exports to Mexico raise additional concerns as to the feasibility of securing adequate natural gas supply in the near term.\textsuperscript{15} SRP fully expects additional natural gas infrastructure will be needed to meet demand driven by 111(d) plan compliance. In addition to expanding natural gas pipeline infrastructure, SRP believes it likely that additional electric transmission capacity will be needed to ensure adequate ability to transfer electricity from NGCC facilities into SRP’s service territory.

Significant time will be required to site, plan, design, permit, and construct the new infrastructure required to meet the interim and final goals of a 111(d) program. In Arizona, more than 80\% of the land is owned by federal and state governments and tribal nations. Siting and permitting of electricity and gas transmission infrastructure on federal or tribal land is subject to many processes and procedural requirements for compliance that can threaten timely completion of these projects.

In 2009, nine federal agencies, led by the U.S. Department of Energy, executed a joint Memorandum of Understanding (MOU) in an effort to improve coordination in working through the federal approvals required for energy infrastructure projects.\textsuperscript{16} The White House Council on Environmental Quality (CEQ) has moved a step further by establishing the Rapid Response Team for Transmission (RRTT). As stated by CEQ, the “\textit{RRTT aims to improve the overall quality and timeliness of electric transmission infrastructure permitting, review, and consultation by the Federal government on both Federal and non-Federal lands}...”\textsuperscript{17}

The initial focus of the RRTT has been on seven pilot projects. Five of those projects are located in the Western U.S., including one project that crosses portions of Arizona and New Mexico, the

\textsuperscript{15} See http://www.eia.gov/naturalgas/weekly/archive/2014/08_07/index.cfm.


\textsuperscript{17} Interagency Rapid Response Team for Transmission. White House Council on Environmental Quality. See http://www.whitehouse.gov/administration/eop/ceq/initiatives/interagency-rapid-response-team-for-transmission.
SunZia Southwest Transmission Project. As discussed in more detail in Appendix A, the lead federal agency overseeing the necessary approvals for this project is the U.S. Department of Interior’s Bureau of Land Management (BLM). Cooperating agencies participating in project permitting include: Arizona Department of Transportation, Arizona State Land Department, Arizona Game and Fish Department, National Park Service, New Mexico Spaceport Authority, New Mexico State Land Office, U.S. Army Corps of Engineers, Holloman Air Force Base, Ft. Bliss (U.S. Army), White Sands Missile Range (U.S. Army), Ft. Huachuca (U.S. Army), U.S. Fish and Wildlife Service, the Department of Defense Siting Clearinghouse, and the Bureau of Indian Affairs.

The purpose of the SunZia Project is to transport electricity generated by new power generation resources to western power markets and load centers. The project consists of two 500 kilovolt transmission lines originating at a new substation in Lincoln County in the vicinity of Corona, New Mexico, and terminating at the existing Pinal Central Substation in Pinal County near Coolidge, Arizona, which is operated by SRP.

Work related to obtaining project approvals began in September 2008 when project proponents filed an application for a right-of-way across BLM lands, but approval has not yet been provided. At this time, it is projected that federal permitting will be complete in 2015, more than 6 years after it was initiated. Project construction is expected to take an additional 3 years.

Although SRP’s comments focus on the SunZia effort as it is being proposed to help facilitate the availability of additional generation resources for Arizona, none of the five western projects under review of the RRTT has secured the approvals necessary to complete project construction. Although EPA might express optimism that approvals for the new gas pipeline and electric transmission projects necessitated by the Proposed Rule will take less time than the SunZia Project, the Agency cannot guarantee this fact, particularly given the high probability any project undertaken in Arizona will require multiple federal and state approvals before it can proceed.

An additional, significant complication to accelerated construction of new NGCC units is the presence of nonattainment areas within a state. Maricopa County and portions of Pinal County do not meet the current ozone standard of 75 parts per billion (ppb). EPA will soon be making revisions to the National Ambient Air Quality Standards (NAAQS) for ozone. The Clean Air

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Scientific Advisory Committee (CASAC) Ozone Review Panel has determined that “there is adequate scientific evidence to recommend a range of levels for a revised primary ozone standard from 70 ppb to 60 ppb.” The Western States Air Resources Council (WESTAR) completed an assessment of the potential expansion of nonattainment areas within the state under a lower standard using attainment test software. Assuming that EPA finalizes an ozone standard at 65 ppb – in the middle of the range recommended by CASAC – much of the state could transition to nonattainment status, as shown in Figure 3-3.

**Figure 3-3. WESTAR Modeled Ozone Nonattainment Area at 65 ppb**

As EPA is aware, to construct a source in a nonattainment area, the project developer would need to obtain emissions offsets, which are not readily available. Projects are often delayed to allow for development of needed offsets through other air quality control projects.

Even without considering these significant constraints, Arizona’s treatment under the Proposed Rule is inequitable when compared to the rest of the nation. EPA’s proposed final goal for Arizona would require a 52% reduction in CO$_2$ emissions intensity from the proposed program.

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baseline year of 2012; only one state, Washington, is being asked to do more. Interestingly, Arizona and Washington are similar in that both states currently have a large percentage of carbon-free generation. Yet it appears that both states, as well as others that have already made significant investment in carbon-free resources, are penalized under EPA’s proposal by being asked to do more than neighboring states with minimal carbon-free generation.

As illustrated in Figure 3-4 on the following page, which was prepared by ADEQ, Arizona’s emissions reduction requirement is significantly more stringent than the requirements for neighboring states; when compared to Utah, for example, Arizona’s goal is nearly two times as stringent.

3.2 EPA Should Treat Arizona As a True Partner in Establishing 111(d) Performance Standards

Section 111(d) of the CAA provides states with flexibility to develop performance standards that best address specific state factors. Thus, while EPA may require states to submit plans that contain performance standards, EPA may not dictate the form and content of those standards, unless a state fails to submit an acceptable plan.22

In the Proposed Rule, EPA determines the BSER and effectively sets the performance standards for existing EGUs through mandatory state CO₂ emissions rate goals. EPA states in the proposal that “the goals are binding, and the states, in their CAA section 111(d) plans, must meet those goals and may not make them less stringent.”23 EPA has limited the states’ role to developing the compliance plans that demonstrate to EPA how the interim and final goals will be met.

SRP believes that EPA must provide Arizona with the flexibility to determine the best reduction options for the state and establish the performance standards for each EGU taking into account each EGU’s unique characteristics. SRP understands EPA’s view that the use of the BSER building blocks to achieve compliance is not mandatory and states may use other strategies to reduce CO₂ emissions, but the goals set by EPA are so constraining that Arizona lacks any realistic alternative compliance options. This lack of flexibility was highlighted by comments submitted to EPA by ADEQ on August 22, 2014.24 Under EPA’s current proposal, there is no way for Arizona to achieve the interim and final goals without giving up a significant amount of reliable, affordable generation resources and engaging in massive investment in new energy infrastructure with no guarantees these new facilities can be in service in the timeline mandated by EPA.

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22 CAA § 111(d)(2)(A); see also Section 5 of these comments.
Figure 3-4. Energy Mix in Arizona and Neighboring States

ENERGY MIX CHART

Comparison of CO₂ emissions (lbs.) / state electricity generation in megawatt-hour (MWh)

ARIZONA

REDUCTION: 51.7%
GOAL: 702 lbs./MWh
2012 Actual: 1,453 lbs./MWh

NEW MEXICO: 34.0% REDUCTION
2030 GOAL: 1,048 lbs./MWh
2012 Actual: 1,586 lbs./MWh

COLORADO: 35.4% REDUCTION
2030 GOAL: 1,108 lbs./MWh
2012 Actual: 1,714 lbs./MWh

UTAH: 27.1% REDUCTION
2030 GOAL: 1,322 lbs./MWh
2012 Actual: 1,813 lbs./MWh

TEXAS: 39.1% REDUCTION
2030 GOAL: 791 lbs./MWh
2012 Actual: 1,298 lbs./MWh

NEVADA: 34.5% REDUCTION
2030 GOAL: 647 lbs./MWh
2012 Actual: 988 lbs./MWh

CALIFORNIA: 23.1% REDUCTION
2030 GOAL: 537 lbs./MWh
2012 Actual: 698 lbs./MWh

Source: https://www.epa.gov/energy/power-planmaps
Publication Number: C-44-20
Congress clearly intended section 111(d) regulations to employ the framework of cooperative federalism.\textsuperscript{25} Congress further provided that states are to be given broad discretion to develop their section 111(d) plans and to implement them based on specific state concerns and needs. Specifically, section 111(d) contemplates that states will consider the remaining useful lives of facilities subject to regulation and provides the states significant freedom to consider “other factors” as well in developing the state plan. Taking into account these various factors, states may then grant individual sources longer periods of time to comply or may apply less stringent standards to a specific source or sources than EPA has set forth in the emission guidelines. This is consistent with EPA’s own acknowledgement that “[s]tates will be free to vary from the levels of control represented by the emission guidelines...In most if not all cases, the result is likely to be substantial variation in the degree of control required for particular sources, rather than identical standard for all sources.”\textsuperscript{26}

The Proposed Rule effectively eliminates key energy policy choices that should be left to Arizona. This is not what Congress provided in the CAA nor is it what Congress envisioned in its approach. Section 111(d) expressly states that standards of performance are to be set by the states and must apply to individual sources. It is difficult to see how the approach set out in the Proposed Rule implements the cooperative federalism the CAA embodies.

3.3 Proposed Improvements to the Goal Calculations for Arizona
SRP worked with the other members of the Arizona Utilities Group (AUG) to develop proposed improvements to the goal calculations for Arizona. If EPA implements the proposed improvements to Arizona’s goal calculations, as described in sections 3.3(b) and 3.3(c) below, the impact to SRP customers alone would be $2.4 billion less than if SRP were forced to implement the rule as proposed by EPA. SRP encourages EPA to implement these improvements to change Arizona’s interim and final goals. Beyond the significant cost savings for customers, it is important for EPA to support a rational path for carbon reductions that fully accounts for the complex structure of the country’s current electric generation and transmission grid, natural gas supply network, and the recent infrastructure investments mandated by EPA through other CAA regulations.

(a) Allow Arizona to Determine Path to 2030 Goal
The most appropriate solution to address the constraints imposed by the interim goal currently proposed for Arizona is for EPA, as contemplated and directed by Congress, to give Arizona the latitude to define and track its own progress towards the state final emissions rate goal. Rather than mandating an enforceable interim goal, EPA should give Arizona (and other states)

\begin{flushleft}
\textsuperscript{25} See Section 5 of these comments for additional discussion.
\end{flushleft}
discretion to develop an individualized plan that establishes programs and measures that set the state on an achievable compliance path to meet the established goals.

In particular, EPA should allow each state to make its own determination as to which measures can be implemented on a time table that is manageable for the state but leads to achievement of the 2030 goals. A state-based approach to interim progress aligns with EPA’s acknowledgment that each state has a unique mix of energy resources. This action would provide states with the true flexibility contemplated by 111(d) and the ability to develop plans that more fully recognize an achievable path to 2030.

SRP is a member of the Coalition for Innovative Climate Solutions (CICS) and supports a CICS proposal previously submitted to the Proposed Rule docket that asks EPA to base agency approval of interim state plans on certain procedural and substantive criteria.27 The procedural criteria would ensure that state plans are credible and enforceable, and the substantive criteria would ensure that the plans consider factors important to controlling CO₂ emissions from the power sector. The criteria would serve as the basis for an inquiry into whether a state plan adequately demonstrates that it will lead to compliance with the state’s 2030 goal.

For example, in evaluating state plans, EPA could consider the following procedural criteria:

- Whether the plan was considered and approved in a regulatory/public process allowing for comment from interested parties.

- Whether the plan milestones are established and monitored by a competent state entity, e.g., the state public service commission (PSC), the state department of environmental quality, or other recognized governing authority (RGA), such as the publicly elected boards for public power entities like SRP. For example, the PSC may be the state agency responsible for oversight of a renewable portfolio standard (RPS) program or may require electric generators in the state to submit an IRP.

- Whether the state plan has an appropriate tracking and monitoring system in place and a mechanism to reopen or amend the plan at appropriate intervals.

- Whether the state plan considered and accounted for the retirement of GHG-emitting units prior to 2012, and whether the state plan includes requirements, verifiable through legal obligation, for the retirement of certain units between 2012 and 2030.

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• Whether the state plan includes reasonable projections of future emissions from the affected units. For example, does the plan project the construction of new, low-carbon or zero carbon generation? What impact does this new construction have on the emissions or emission rate of the portfolio of existing units?

• Whether the plan requires monitoring and reporting of emissions and energy generation from affected units on a periodic basis and the calculation of state progress toward to the goal.

EPA also could consider the following substantive criteria:

• Whether the state PSC or RGA requires a company with affected EGUs to consider emissions of GHGs. For example, does the regulatory authority require an estimate of the carbon intensity from new or decommissioned units, or an analysis of how a company would comply with the 111(d) plan?

• Whether the state PSC or RGA requires an electric distribution company to support, or achieve, certain levels of energy efficiency from customers; whether the level or cost threshold for such programs is appropriate.

• Whether the state PSC or RGA has an RPS, capacity standard, tax incentives or other renewable promotional programs; whether the state plan appropriately seeks to establish or expand such programs; whether the RPS creates a verifiable legal obligation.

• Whether the state plan includes an analysis of the potential to retire or reduce the utilization of older, high-carbon EGUs and consider the construction or increased utilization of lower carbon EGUs, taking into consideration costs, energy requirements, electric system reliability, remaining useful life, technical feasibility due to transmission constraints, contractual limitations, etc.

• Whether the state has converted EPA’s rate-based goal to a mass-based goal and provided the methodology for this conversion.

• Whether the state is participating in a multi-state emissions trading program designed to achieve GHG emission reductions over the applicable time period; whether the plan is structured in a way that will allow it to achieve emission reductions or emission rate improvements.

• Whether the state is participating in a multi-state program to cooperate on elements of
the state’s compliance program, such as accounting for use of renewable energy capacity or credits, or measurement and verification of energy efficiency programs.

- Whether other elements of the plan will help reduce the GHG emissions or carbon intensity of the electricity supply.

It is not necessary for a state to include all of these criteria in its plan; a selection of these (or similar) substantive or procedural criteria will allow EPA to determine that a state is taking the appropriate, state-specific measures and steps to achieve a reduction in GHG emissions from existing EGUs. Importantly, using such an approach is consistent with the structure and intent of section 111(d) of the CAA to allow the states to set the performance standards for their own sources based on the unique circumstances of the state.

(b) Accommodate Remaining Useful Life

EPA’s proposed goals for Arizona are likely to force the retirement of most, if not all, of Arizona’s coal-fired EGUs. Two of these Arizona units are less than 10 years old and several recently have been upgraded with new pollution control equipment to comply with other EPA directives. It is critical that EPA give the states flexibility to address these investments in planning for 111(d) compliance.

Specifically, SRP urges EPA to allow Arizona and other states to consider “remaining useful life” in developing the state’s emission reduction plan. Both the CAA itself and existing 111(d) regulations explicitly provide states with the ability to deviate from standards established by EPA based on analysis of the “remaining useful life” of an affected facility or class of facilities.\(^\text{28}\) EPA must appropriately recognize that remaining useful life is a key tool in state planning for 111(d) compliance.

This is a particularly critical issue for SRP, where EPA’s proposal, if left unchanged, could force closure of the Coronado Generating Station (CGS) and Springerville Generating Station (SGS) by 2020. SRP owns both units at CGS and one of the four currently operating units at SGS (Unit 4). Net book value, as of October 31, 2014, exceeds $1.5 billion for these three units – $630 million for CGS Units 1 and 2 and $900 million for SGS Unit 4.

\(^{28}\) 42 U.S.C. § 7411(d)(1)(B) (“Regulations of the Administrator under this paragraph shall permit the State 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”).
SRP recently completed air pollution control equipment upgrades on CGS Units 1 and 2, which cost approximately $470 million. The bond financings for this project were approximately 30 years with final bond maturity occurring in 2041. In addition, EPA established emission control requirements based on an assumed remaining useful life of 20 years, which presumed that CGS would continue to operate beyond 2030.

In EPA’s 2012 Best Available Retrofit Technology (BART) Federal Implementation Plan (FIP) for CGS, EPA used a “remaining useful life” of 20 years to calculate the cost-effectiveness of adding an additional selective catalytic reduction (SCR) system at this plant. EPA based this value on a default 20-year amortization period recommended in the EPA Control Cost Manual because EPA was unaware of any federal or state requirement that would require the sources to shut down by a specified date.

The bond financing for construction of SGS Unit 4, which came on line in December 2009 at a cost of $1 billion, was approximately 30 years with final bond maturity occurring in 2038. As mentioned above, EPA acknowledges that the useful life of a coal-fired unit operating to meet base load demand is 40 years. Accordingly, EPA should expect that SGS Unit 4 would remain operating as a baseload facility until at least 2049. SRP does not own SGS Unit 3, which came on line in 2006 at a cost of $939 million. But, SRP has a 30-year power purchase agreement to purchase power from Unit 3 with anticipation that this unit, which is nearly identical to Unit 4, also would have a useful life of 40 years.

SRP’s investments in the CGS and SGS units are substantial and are being recovered in the rates of the customers SRP serves. Prematurely retiring Arizona coal generation will place an

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29 These upgrades included installation of low nitrogen oxide burners with overfire air systems and wet flue gas desulfurization equipment on both units, as well as selective catalytic reduction equipment on Unit 2. All of these significant upgrades were completed between 2009 and 2014.


31 On November 11, 2014, SRP submitted a supplemental petition for partial reconsideration and stay of EPA’s final rule (“Supplemental Petition”). Within this Supplemental Petition, SRP states that “EPA’s planned carbon dioxide (CO₂) performance standards for existing coal- and natural gas-fired electric generating units, as described in the Agency’s proposed rule published on June 18, 2014, 79 Fed. Reg. 34,830 (“111(d) Proposal”), will likely require Coronado to cease operations in 2020. The publication and pendency of the 111(d) Proposal create enormous uncertainty regarding the future viability of Coronado and whether installation of costly new emission controls to satisfy BART requirements, such as those imposed by the Final Rule, would be reasonable or economically feasible.” See Supplemental Petition at 2 (included as Appendix K of these comments).

unreasonable burden on electricity customers who would be required to cover not only the resulting stranded costs, but also the cost of building the new infrastructure required to replace this generation.

In addition to electric rate impacts, SRP as the operator of CGS and Tucson Electric Power (TEP) as the operator of SGS requested assistance from Arizona State University’s (ASU) Seidman Institute to quantify how the loss of CGS and SGS under a 111(d) compliance plan would affect the local and state economy.

ASU examined the direct, indirect, and induced economic impacts of CGS and SGS, individually and jointly, at the county and state level. The economic contribution of the plants was assessed for the year 2013, the most recent year for which complete data is available. An Arizona-specific version of the Regional Economic Models Inc. (REMI) model was used for the analysis. REMI is widely recognized by business and academic communities as the leading economic modeling tool available. This model is currently used by ASU for all business expansion and relocation studies commissioned by the Arizona Commerce Authority.

While ASU’s entire report is contained in Appendix C of these comments, the primary findings from the study are outlined below:

- CGS and SGS employ 218 and 332 full-time equivalent (FTE) staff, respectively. Taking into account direct, induced, and indirect impacts, CGS and SGS contribute to approximately 4,000 jobs per year in the state of Arizona, nearly 70% of which are located in Apache County.

- The state of Arizona and Apache County in particular will be severely impacted if CGS and SGS cease operations. Apache County could lose 2,700 FTE jobs and $600 million in annual gross state product.

- Based on property tax information provided by SRP and TEP, ASU affirmed that the shutdown of CGS and SGS would cause over half of Apache County’s property tax value to be eliminated, including two thirds to three quarters of the property tax value that supports the local school districts.

- With limited alternative employment opportunities, there will be an associated exodus of plant employees from the region. This mass exodus will clearly result in a drop in housing values, shuttering of local businesses, and closing of schools as the remaining population is left with the full financial burden of supporting communal services, such as schools, medical centers, library districts, and fire districts.
Many states can avoid these types of devastating economic impacts because they have sufficient headroom in their interim and final goals to retain newer or recently upgraded EGUs after the application of Building Block 2. Unfortunately, this is not the case in Arizona. When Building Block 2 is applied in the state, Arizona has no ability to retain newer or upgraded EGUs that have significant remaining asset value.

SRP urges EPA to provide Arizona with the same level of flexibility to achieve 111(d) state goals that is afforded to the rest of the nation. EPA can provide such flexibility by properly considering remaining useful life in application of Building Block 2. Specifically, EPA should adjust the assumptions made under Building Block 2 consistent with a recommendation developed by the AUG.

The AUG recommends a few targeted changes to the Building Block 2 calculation that would result in a final rule that: (1) does not threaten electric reliability; (2) still obtains substantial reductions in carbon emissions both in Arizona and nationwide; and (3) would be substantially more cost-effective and attuned to the statutorily-mandated “remaining useful life” concept. These changes include the following:

- 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:
  - January 1, 2020;
  - January 1 of the year following 40 years after initial commencement of operation; or
  - January 1 of the year following 20 years after commencement of operation of significant air pollution controls at any EGU if installation occurred prior to issuance of the final 111(d) rule, or after commencement of operation of selective non-catalytic reduction (SNCR) or electrostatic precipitators (ESP) 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).

- 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

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33 Significant air pollution control equipment includes selective catalytic reduction systems, baghouses, or flue gas desulfurization systems.
the final rule and the date of shutdown or natural gas conversion is prior to January 1, 2030.

- Coal-fired EGUs that do not redispacht prior to January 1, 2030 remain coal-fired EGUs for purposes of calculating the interim and final goals.

SRP believes this proposal is consistent with concepts introduced in the NODA, and provides significant and much-needed relief to states that are overly burdened by Building Block 2, with minimal impacts to the overall emissions intensity reductions EPA will achieve with its Proposed Rule. Not only will this proposal accommodate proper consideration of remaining useful life in setting performance standards for existing sources, but it will ultimately rectify a basic equity issue associated with the currently proposed state goals.

Figure 3-5 on the following page provides an estimate of the impact of the changes proposed by the AUG on the 2030 CO₂ emission rate goals for each state. This figure was developed by SRP using a database developed and maintained by The Brattle Group. The database provides a catalog of data on the U.S. coal fleet, including when the units commenced operation and information on major pollution control projects.

In Figure 3-5, the red bars show the amount of coal generation that remains in each state following the application of Building Block 2, as proposed by EPA. The blue bars show the amount of coal generation that would remain in 2030 if the changes proposed by the AUG were adopted by EPA. If the red bar exceeds the blue bar, the changes proposed by the AUG would have no impact on the state’s 2030 emission rate goal because the state would already have been allowed to retain that amount of coal under the EPA’s proposal. Ultimately, Figure 3-5 demonstrates that the impact of the changes proposed by the AUG would be minimal nationwide – only a handful of states that are significantly and disproportionately impacted by Building Block 2 would be affected by the proposed changes.

(c) Revise Emission Rate for Arizona’s Existing NGCC Units
In calculating the emission rate targets for Arizona, EPA assumed that NGCC units would operate in future years at an emission rate of 900 lb CO₂/MWh. This value is the combined average annual emissions rate for the NGCC units in Arizona during 2012. However, this emission factor is not consistent with EPA’s analysis regarding emission rate capabilities for new, highly efficient units under section 111(b).³⁴

³⁴ In EPA’s January 2014 proposal, CO₂ emission rates for new units were proposed at 1,000 lb CO₂/MWh for NGCC units with a capacity greater than 850 MMBtu/hour and 1,100 lb CO₂/MWh for NGCC units with a capacity of 850 MMBtu/hour or less. See 79 Fed. Reg. 1,430, 1,433 (Jan. 8, 2014).
This single year snapshot could underestimate the emission rates for these units given that these units could operate differently in the future. EPA should remain consistent with its analysis regarding the emission rate that is continuously achievable for NGCC units and use a rate that is no lower than the rate that the agency proposed for new sources under section 111(b).

3.4 Additional Considerations for Goal Calculation and Compliance

(a) Summer Net Dependable Capacity

In implementing Building Block 2, EPA makes assumptions about the availability of existing NGCC unit capacity in Arizona that are incorrect. EPA used the nameplate capacity to determine MW available for redispatch. Generators cannot achieve nameplate capacity in real world conditions due to parasitic load, and high and low ambient temperatures can further limit a unit’s actual capacity during summer and winter months. As shown in Table 3-1 on the following page, these differences are significant for Arizona’s existing NGCC fleet and demonstrate that nameplate capacity is not an appropriate measure of actual NGCC capacity in general or capacity that is available year-round.
Because EPA’s calculations in support of Building Block 2 have a significant impact on future use of coal generation capacity in Arizona, EPA should use summer net dependable capacity, as reported to the North American Electric Reliability Corporation (NERC) for analysis of system reliability, in calculation of available existing NGCC capacity available for use under Building Block 2.

(b) Crediting Carbon-Free Generation

EPA’s proposal fails to fully recognize the large percentage of carbon-free generation resources already present in Arizona. Arizona is home to the Palo Verde Nuclear Generation Station (PVNGS), the largest nuclear power generating station in the United States. SRP owns 17.49% of this facility and it is an important provider of baseload generation in the company’s resource portfolio.

For the purposes of goal-setting, EPA claims that a certain percentage of the U.S. nuclear fleet is at risk of retiring for various reasons and that “preserving the operation of at-risk nuclear capacity would likely be capable of achieving CO₂ reductions from affected EGUs at a reasonable cost.” EPA has therefore proposed to include an “at-risk” nuclear component in the CO₂ goals for all states with nuclear generation. This “at-risk” nuclear component is calculated as 5.8% of the nuclear capacity in each state, assuming a 90% capacity factor.

EPA’s incorporation of a percentage of PVNGS’s 2012 generation into Arizona’s goals based on a presumption that 5.8% of U.S. nuclear capacity is at risk of retirement provides no substantive recognition of the fact that this facility comprises approximately one-third of the generation produced in Arizona and is not at risk of near-term retirement. The U.S. Nuclear Regulatory Commission approved the extension of all three PVNGS units by an additional 20 years. Unit 1 is permitted to operate through 2045, Unit 2 through 2046, and Unit 3 through 2047.

Instead of applying a generic “at-risk” factor to all existing nuclear generation, EPA should apply a site-specific “at-risk” factor where nuclear generation is really at risk. With the current

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Table 3-1. Comparison of Actual Arizona NGCC Capacity to Nameplate Capacity by Season

<table>
<thead>
<tr>
<th>Comparison of Summer and Winter Capacity to Nameplate Capacity</th>
<th>Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Nameplate Capacity</td>
<td>11,202</td>
</tr>
<tr>
<td>Total Summer Capacity</td>
<td>9,303</td>
</tr>
<tr>
<td>Difference Between Nameplate and Summer Capacity</td>
<td>1,899</td>
</tr>
<tr>
<td>Total Winter Capacity</td>
<td>9,947</td>
</tr>
<tr>
<td>Difference Between Nameplate and Winter Capacity</td>
<td>1,255</td>
</tr>
</tbody>
</table>

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approach, EPA is diluting impacts where nuclear generation is actually “at risk” and creating issues where it is not at risk, such as in Arizona. EPA should remove the “at-risk” nuclear component from the goal calculation for Arizona.

For the purposes of compliance planning, EPA proposes that nuclear generation would count towards compliance with a state goal only if this generation meets or exceeds a 90% capacity factor. If the nuclear generation does not meet the 90% capacity factor threshold in a given compliance year, the state would have to implement more renewable generation or energy efficiency measures to offset the shortfall in nuclear generation. This approach is problematic as it could be routine that the capacity factor of a nuclear plant falls below 90% in any given year due to outages required for refueling, regular maintenance, or to address certain regulatory required modifications. By relying on a 90% capacity factor, EPA is penalizing rather than rewarding states that have nuclear generation.

Arizona Public Service (APS), the operator of PVNGS, developed a concept for how EPA could provide even more meaningful credit to nuclear generation in its Proposed Rule that would not dramatically change Arizona’s emissions rate goals, but would provide better recognition to Arizona for its nuclear resource. SRP supports APS’s proposed approach as a more appropriate methodology for incorporating nuclear generation into the CO₂ goals. The proposal has two components:

1. Remove the 5.8% nuclear component from the denominator of the EPA’s CO₂ goal calculation.

2. When demonstrating compliance with the CO₂ goals, allow states to take credit for that portion of annual nuclear generation in excess of the average historical performance of the fleet. The average capacity factor of a nuclear unit over its lifetime is approximately 80%. Therefore, beginning in the first compliance year associated with the rule (2020), and in each year thereafter, if a nuclear unit exceeds 80% capacity factor, allow any generation in excess of that 80% capacity factor threshold to be included in the denominator of the CO₂ emission rate calculation, which would provide credit towards compliance with the state’s CO₂ goals.

SRP urges EPA to consider adopting the methodology proposed by APS to credit Arizona’s investment in PVNGS, and similar investments in other states. This approach would ensure states with nuclear generation like Arizona are not unduly penalized, as well as provide those states with a meaningful incentive to keep nuclear EGUs online and operating.

36 See comments submitted by APS for an explanation of how this value was derived.
While SRP has concerns about EPA’s failure to recognize the full value of Arizona’s carbon free generation, SRP applauds EPA’s recognition that Arizona’s 111(d) compliance plan should have the option to incorporate CO\(_2\) reductions associated with renewable energy resources located outside of the state. The ability to invest in renewable resources, both in-state and out-of-state, allows utilities to engage in more cost-effective development of these resources and promotes greater diversity of resource portfolios. While some parties commenting on this proposal have expressed a concern that RE attributes could be double-counted by being claimed in multiple state plans, SRP is confident that states can avoid this issue through adoption of systems that create and track the use of renewable energy credits (REC), such as the Western Renewable Energy Generation Information System (WREGIS). \(^{37}\)

Using REC systems, such as WREGIS, would greatly expand RE procurement options for all participants. States would gain access to RE that could be used for compliance regardless of its deliverability. Participants with larger compliance obligations could purchase RECs from out-of-state RE projects that are more competitively priced than those that might be built in state. Likewise, states with an abundance of RE projects beyond their compliance obligations could benefit by selling RECs to others. To the extent possible, SRP encourages EPA to provide states support in using RE accounting systems to fully realize available RE procurement options. \(^{38}\)

(c) Changes to Program Baseline Year

To set realistic and equitable state goals, EPA must start with a baseline period that is representative of actual generation and CO\(_2\) emission levels. The 2012 baseline period in the Proposed Rule is not representative, in part because EPA did not correct for anomalous events that impacted total CO\(_2\) emissions in that single year. EPA should consider alternative multi-year baseline periods to minimize the impact of anomalies in 2012. At minimum, EPA should address certain anomalies to 2012 data that unfairly penalize some states and/or companies. Numerous anomalous events can occur during any single year, as demonstrated by 2012. These anomalies include increased utilization of certain affected EGUs due to extreme weather events, atypically low CO\(_2\) emissions from coal-fired generation due to historically low natural gas prices, a changing portfolio (additions and retirements) of available units for dispatch,  

\(^{37}\) WREGIS is an independent, renewable energy tracking system for the region covered by the Western Electricity Coordinating Council. WREGIS tracks renewable energy generation from units that register in the system by using verifiable data and creating RECs for this generation. See www.wecc.biz/WREGIS/Pages/Default.aspx.

\(^{38}\) Implementation of tracking and crediting systems have been successful in other EPA CAA programs. Specifically, under EPA’s Acid Rain Program, EPA implemented a sulfur dioxide trading program. EPA recognizes that programs such as these can provide meaningful, cost-effective emissions reductions. (“Through the market-based allowance trading system, utilities regulated under the Acid Rain Program decide the most cost-effective way to use available resources to comply with the requirements of the Clean Air Act.” See http://www.epa.gov/airmarkets/progsregs/arp/s02.html.)
abnormally high levels of hydroelectric generation, and unit outages for repair or retrofits. For example, in Arizona, one affected EGU, Springerville Unit 3, operated at a reduced capacity factor of approximately 54% in 2012 due to unplanned outages for steam turbine work. This much lower capacity factor should not be deemed to be representative of typical operations for this baseload unit.

Another example is the unusually high hydroelectric production experienced in the Pacific Northwest during 2012 resulted in unusually low fossil power generation. In that region, fossil resources dispatch only after all hydroelectric and wind resources have been fully allocated. Because of historically high hydroelectric availability in 2012, Oregon’s only coal-fired power plant ran at an unusually low capacity factor of approximately 50%. Across the region, hydroelectric generation was 110% in 2012, as compared with average levels. This equates to 14.3 gigawatt-hours of carbon-free energy generation above an average water year, which lowered Pacific Northwest emissions by 5.7 million tons, or 22%. In Washington, hydroelectric production ran at 127.7% in 2012, as compared to long-term average hydropower generation rates. By mandating emission reductions from the 2012 baseline, EPA has proposed goals for states in the Pacific Northwest that are artificially skewed relative to states that rely more on thermal generation. Around the country, there are other examples of such anomalies in 2012, as would be the case for any single-year baseline.

As EPA has noted in previous rulemakings, an EGU’s operations (and, consequently, its CO₂ emissions) will vary greatly over the course of any given year.

“A cold winter or hot summer will result in high levels of ‘normal’ operations while a relatively mild year will produce lower ‘normal’ operations . . . . [E]lectricity demand and resultant utility operations fluctuate in response to various factors such as annual variability in climatic or economic conditions that affect demand, or changes at other plants in the utility system that affect the dispatch of a particular plant.”

As a result, under the New Source Review program, EPA applies a presumption that any 24-month period in the 5 years preceding a project is representative of normal operations.

A multi-year baseline period would smooth out the anomalies associated with 2012 and more accurately represent the natural variations inherent in the electric industry. While anomalous events occur every year, these events do not all have the same impact on operations and emissions. As a result, any single-year baseline period will not accurately represent normal

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operations of the energy industry. A multi-year baseline would better represent the natural yearly variation and, thus, better depict normal operations.

In the NODA published on October 30, EPA acknowledged stakeholder concerns about use of 2012 as the baseline year for state goal calculation and asked for comment on whether the agency should use a different single data year or the average of a combination of years, such as 2010, 2011, and 2012. For the reasons discussed above, SRP supports the use of an alternative multi-year baseline for purposes of goal setting.
4. **SRP CONCERNS REGARDING EPA’S RELIABILITY AND COST MODELING ANALYSIS**

EPA conducted a separate analysis during development of the agency’s 111(d) proposal to assess the cost and reliability implications of the Proposed Rule (“Reliability and Cost Modeling Analysis”). To perform this assessment, EPA used the Integrated Planning Model (IPM), which is a multi-regional programming model of the U.S. electric power sector that EPA uses to assess potential costs and reliability implications of the agency’s rulemaking actions. EPA states that it uses IPM to “project likely future electricity market conditions with and without the proposed rule.” EPA concluded from its reliability analysis that “…implementation of this rule can be achieved without undermining resource adequacy or reliability.”

SRP retained The Brattle Group (“Brattle”) to conduct a detailed review of EPA’s Reliability and Cost Modeling Analysis. The review focused on the “Base Case” (without the implementation of the Proposed Rule) and “Option 1” (assuming each state meets its individual CO₂ goals without a regional compliance plan). Brattle’s findings are detailed in a white paper that is included in Appendix D of these comments (“Brattle White Paper”). A summary of these findings is provided below.

### 4.1 EPA’s Reliability and Cost Modeling Analysis is Based on an Unrealistic Compliance Approach for Arizona

EPA’s Reliability and Cost Modeling Analysis predicts that Arizona would adopt a significantly different approach to meet the state’s CO₂ goals than EPA assumed in setting those goals. The two approaches are compared using Arizona’s 2030 final goal in Figure 4-1 on the following page. As can be seen in the figure, the goal setting approach assumes that all coal-fired generation would be displaced with existing, in-state NGCC generation, and that renewable energy and energy efficiency measures would increase according to the assumptions EPA made in establishing Building Blocks 3 and 4, respectively. In contrast, EPA’s Reliability and Cost Modeling Analysis predicts that Arizona would import more than 5,800 MW of electricity from outside of the state, achieve even greater energy efficiency savings than assumed in setting the state goals, and keep 1,500 MW of coal generation online.

SRP has significant concerns that the assumptions used in EPA’s Reliability and Cost Modeling Analysis are unrealistic, particularly with respect to electricity imports, power plant ownership, and energy efficiency, as described in detail below. These concerns have been raised with EPA during the public comment period. In those discussions, EPA has stated that the IPM is just a

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41 Id.
tool to showcase one method states can use to comply, but that it is not intended to define a specific path that states would or should take to comply with the Proposed Rule. While SRP understands that states can determine the ultimate path forward, EPA relied on the results from IPM to assess the cost and reliability implications of the Proposed Rule. SRP does not believe it is appropriate for EPA to rely on incorrect and unrealistic assumptions in an attempt to show that the Agency’s proposal is feasible and cost effective.

Figure 4-1. Comparison of EPA-Assumed Compliance Approaches for Arizona

4.2 EPA Assumes an Unrealistic Reliance on Electricity Imports to Meet Peak Demand

EPA’s Reliability and Cost Modeling Analysis predicts that Arizona would import significant quantities of energy to meet peak demand and reserve margin requirements. Arizona is currently a large net exporter of electricity. As shown in Figure 4-2 on the following page, the IPM predicts that Arizona will transition from a net exporter of energy to a significant net importer by 2020 – only 2.5 years after EPA takes action on the state’s compliance plan. Even
more problematic, the IPM assumes that the imported electricity would come from California and the Pacific Northwest during the peak hours, as shown in Figure 4-3 on the following page.

**Figure 4-2. IPM Assumptions for Net Generation Imported Into Arizona**

![Net Generation Imported into Arizona](image)

EPA has not conducted reviews of existing transmission and generation infrastructure, transmission rights and reservations, or resource ownership and purchase agreements to justify that this significant shift in power flow would be possible in such a short timeframe and that the power flow can be relied upon during times of peak regional demand. The IPM does not consider these constraints and EPA did not perform any of the necessary studies to demonstrate that the major changes required by the Proposed Rule could be implemented without reliability issues. The lack of sufficient study work, which also was noted in comments submitted by EPRI and NERC calls into question the validity and accuracy of EPA’s Reliability and Cost Modeling Analysis.

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42 Comments of the Electric Power Research Institute on Environmental Protection Agency 40 CFR Part 60 at 40, Docket No. EPA-HQ-OAR-2013-0602-21697 (Oct. 20, 2014) (EPRI Comments). ("The proposed EPA rule considers only the adequacy perspective of the reliability impact of the rule and does not address the potential thermal, 

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Arizona would not likely be able to rely so significantly on power from the Pacific Northwest to meet peak demand due to the uncertainty as to whether these resources are available at the time they are needed. Instead, utilities would likely construct new in-state generation (if they can do so given the constraints imposed by other CAA programs) and potentially new transmission to ensure adequate reliability at peak load conditions and minimize risk to customers that might be introduced by heavier reliance on energy markets or power that is generated several states away. In fact, the Arizona Corporation Commission’s (ACC) IRP rules state that utilities cannot rely on capacity that is not sourced from known generation for reserve margin requirements. Siting and construction of new NGCC generation and

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43 NERC, Reliability Impacts Potentially Resulting from the CPP, November 2014, at 26 (see "Studies and Assessments Needed to Support Reliability").

44 Electricity flows in and out of San Francisco are not shown.

transmission will take a significant amount of time and raises concerns about SRP’s ability to serve load and still meet the emission standards in the Proposed Rule.

NERC recognized this issue in comments released in November 2014, as evidenced by the following conclusions that were reached after their own analysis.

- “Areas that experience a large shift in their resource mix are expected to require transmission enhancements to maintain reliability. Constructing the resource additions, as well as the expected transmission enhancements, may present a significant reliability challenge given the constrained time period for implementation.”

- “Long lead times for transmission development and construction require long-term system planning – typically a 10-15 year outlook...”

- “EPA and policy makers should recognize the complexity of the reliability challenges posed by the rule and ensure the rule provides sufficient time for the industry to take the steps needed to significantly change the country’s resource mix and operations without negatively affecting Bulk Power System reliability.”

### 4.3 EPA Did Not Properly Account for Power Plant Ownership

The IPM does not properly account for power plants that are jointly owned. The model assumes that all power generated by a plant located within Arizona is available to meet Arizona’s peak demand, regardless of whether a portion of that plant is owned by an out-of-state entity and their portion of electricity is exported out of state to serve that entity’s load obligations. For example, the IPM assumes that the entire capacity of PVNGS (3,937 MW) is available to meet Arizona’s peak demand. However, less than 50% of PVNGS is owned by Arizona utilities.

In addition, some of Arizona’s largest coal-fired power plants are jointly owned. For these resources, the portion of capacity that is not owned by Arizona utilities likely does not serve Arizona load. The IPM inaccurately assumes that the entire generation capacity from these plants is available to serve Arizona load, whereas in reality, a large fraction of this energy is owned by out-of-state entities and therefore leaves the state.

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46 NERC, Reliability Impacts Potentially Resulting from the CPP, November 2014, at 2.

47 Id. at 20.

48 Id. at 3.
Additionally, many of Arizona’s existing NGCC plants are owned or partially owned by merchant providers. It is inaccurate to assume that generation from merchant-owned NGCC plants serves Arizona load unless a long-term purchased power contract is in place with an Arizona utility serving Arizona load.

Certain Arizona utilities also own power plants that are located outside of the state (e.g., Four Corners Power Plant and San Juan Generating Station in New Mexico). However, on balance, the IPM simulations overstate the generation capacity that is available to serve Arizona load by about 1,650 MW, as shown in the Brattle White Paper.

4.4 EPA Assumes Unrealistically Aggressive Energy Efficiency Measure Implementation

EPA assumes that load growth in Arizona would be reduced dramatically by aggressive implementation of energy efficiency (EE) measures, as shown in Figure 4-4. As can be seen in the figure, EPA effectively assumes that EE can almost completely eliminate future load growth.

Figure 4-4. Energy Efficiency Assumptions in IPM

Developed by: The Brattle Group
Even with high levels of EE, it is unlikely that there would be such a small level of load growth in Arizona when its population has been forecasted to increase 38% to 45% between 2012 and 2030.49

The Brattle White Paper describes a number of concerns regarding EPA’s EE assumptions in the Reliability and Cost Modeling Analysis. The most significant concerns are as follows:

- The EE measures are “hard-coded” into the IPM. In other words, the IPM assumes the full extent of EE measures prescribed by Building Block 4 would be implemented and realized by states, instead of having the model predict how much EE would be adopted based on the cost effectiveness of these measures relative to other resource options. As EPRI explains in its comments, EPA is effectively assuming that EE is so inexpensive that it will be adopted in full in any scenario in which the Clean Power Plan is implemented.50 EPA should allow the model to make that determination.

- EPA ignores the fact that the baseline load forecast already assumes a substantial impact from EE programs, which effectively results in double counting these measures.

- In addition to assuming that high EE levels will be achieved on an annual basis, EPA also assumes that the EE measures can reduce peak demand by the same percentage. Because demand-side EE measures are controlled by end users of electricity, there is no guarantee that end users will be fully implementing the measures at peak demand conditions. Therefore, it is overly optimistic to assume that all EE measures would be available to meet peak demand.

EPRI and NERC likewise expressed concerns about EPA’s treatment of EE in the Reliability and Cost Modeling Analysis.51 NERC concluded the following:

“The EPA appears to overestimate the amount of energy efficiency expected to reduce electricity demand over the compliance timeframe...By overestimating energy efficiency savings resulting in declining electricity retail sales, the results of the entire Regulatory Impact Assessment are concerning from a reliability

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50 EPRI Comments at 51.

51 Id. at 50-53.
To the extent that EE measures are not available or do not end up being adopted at the target levels, additional generating resources would be required to ensure reliability and to comply with the CO₂ goals for Arizona. Due to the stringency of the CO₂ goals for Arizona, the state’s ability to build new resources to replace the EE measures that did not materialize would be significantly constrained.

This is further explained in the Brattle White Paper included in Appendix D:

“...in 2020, if the assumed 4,226 GWh [gigawatt-hours] of EE savings that the EPA assumes for Building Block 4 is not achieved, then Arizona would have to reduce existing CC [combined cycle] generation by 6.38 times the amount of EE or about 27,000 GWh, which is about one-third of 2012 state energy consumption. To replace that reduced generation, the state would have to rely on a combination of additional imports, new combined cycle or new renewables. For context, 27,000 GWh from new combined cycle is about 4.4 GW [gigawatts] of combined cycle at a 70% capacity factor (about seven new plants).”

4.5 EPA’s Reliability and Cost Modeling Analysis Does Not Adequately Address the Reliability Implications of the Proposed Rule

As explained in the previous sections, EPA’s Reliability and Cost Modeling Analysis predicts that Arizona would take a significantly different approach to meet the CO₂ goals than EPA assumed in setting those goals. Both approaches are unrealistic and do not accurately reflect the path that Arizona would likely follow to meet EPA’s stringent CO₂ goals. While EPA’s goal setting approach unrealistically assumes that the existing NGCC plants within the state can replace all coal resources in 2020, EPA’s Reliability and Cost Modeling Analysis is premised on an inappropriate reliance on out-of-state imports, erroneous assumptions about power plant ownership, and overly aggressive energy efficiency assumptions. Both the target setting and compliance analyses are flawed and fail to properly reflect how the rule will affect reliability of energy availability in Arizona.

The AUG contracted with PACE Global to perform an assessment of the impacts to the state that could result from the implementation of the Proposed Rule. A copy of the PACE Global

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52 NERC, Reliability Impacts Potentially Resulting from the CPP, November 2014, at 16.
analysis is included as Appendix E of these comments. This analysis indicated that the interim goals proposed by EPA would generate major reliability concerns in Arizona, as follows.\textsuperscript{53}

- All non-tribal coal in Arizona would need to be retired by 2020, implying a stranded investment of more than $3 billion.

- Coal retirements would result in the need for at least 2.4 GW of incremental natural gas capacity within a 3-year period at a cost of around $2 billion to maintain reserve margins.

- Additional electric transmission infrastructure would be required to ensure electric reliability and deliverability since most coal generation is in the eastern part of Arizona and most of the existing natural gas generation is in western Arizona.

- Additional natural gas pipeline infrastructure would be required to support the two existing main natural gas pipelines serving Arizona since one is already near capacity throughout the year and both are near capacity during peak periods.

\textsuperscript{53} PACE Global, \textit{Assessment of the Clean Power Plan}, November 21, 2014, at 6-7.
5. **SRP CONCERNS WITH EPA’S LEGAL APPROACH TO REGULATION OF EXISTING EGUS UNDER CAA SECTION 111(d)**

5.1 **EPA May Not Adopt Emission Guidelines Under Section 111(d) for Source Categories Regulated Under Section 112 of the CAA**

EPA argues in the legal memorandum accompanying the Proposed Rule that section 111(d) is “ambiguous” about whether the agency may regulate sources under both section 112 and section 111(d) at the same time; therefore, EPA asserts that the Agency is entitled to deference in its determination that it may do so.\(^{54}\) EPA relies on the existence of two amendments to section 111(d) in the 1990 amendments to the CAA for its position of ambiguity. As the Utility Air Regulatory Group (UARG) more than adequately explains in its comments, EPA’s reliance on the existence of the two amendments – one of which was merely a clerical error not codified in the U.S. Code – is an attempt by EPA to expand its regulatory reach beyond that allowed under the CAA and should not be accorded the deference that EPA seeks. Both the statutory language and the legislative history of the CAA make clear that because coal-fired EGUs are regulated under section 112, they may not be regulated under section 111(d).

In 2000, EPA listed coal- and oil-fired EGUs as a “source category” under section 112 of the CAA.\(^ {55}\) In 2012, EPA regulated emissions from these sources under the Mercury and Air Toxics Standards rule.\(^ {56}\) As explained in greater detail in the comments submitted by UARG and others, section 111(d) prohibits EPA from adopting emission guidelines for existing sources that are included in a source category the agency already has regulated under section 112.\(^ {57}\) Thus, because EPA chose to regulate emissions from existing coal-fired EGUs under section 112, it is prohibited from promulgating the Proposed Rule. EPA’s attempt to fashion an ambiguity in the statutory language to support its Proposed Rule is unfounded. Therefore, EPA should withdraw the Proposed Rule.

5.2 **EPA Must Set an Achievable Standard of Performance Based on Measures Integrated Into the Design or Operation of the Source Itself**

In addition to the practical problems with each of the building blocks proposed by EPA (detailed in Section 7 of these comments), EPA’s proposed building blocks suffer from significant legal concerns. Building Blocks 2 through 4 stray far from section 111 requirements because they require emissions reductions from something other than a regulated source. Because this

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54 See Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units (“EPA Legal Memorandum”), at 23.


57 CAA § 111(d)(1)(A)(i).
novel approach has no basis in the CAA, it clearly exceeds EPA’s authority and must be withdrawn.

Under section 111 of the CAA, a standard of performance must be achievable for an individual regulated source based on measures that can be integrated into the source itself. In other words, section 111 establishes a program clearly focused on reducing the rate of emissions from new and existing stationary sources through the application of systems that can be integrated into the source’s design or operation. This fundamental concept of section 111 is clear not only in the language of section 111, but also in the overall context of the CAA and in EPA’s own implementation of section 111.

For the 40-plus years that section 111 has existed, EPA has developed standards consistent with this fundamental concept and has recognized that a standard of performance may not be based on actions taken beyond the source itself that somehow reduce the source’s utilization or be based on a mandate that the source reduce operation. In the current Proposed Rule, EPA ignores this precedence and creates an entirely new approach to standard setting under section 111. Because this unprecedented approach is “inconsistent with the design and structure of the [CAA] as a whole,” the Proposed Rule must be withdrawn.  

As the UARG comments explain in great detail, the CAA’s section 111 program begins and ends with the regulated source. For as long as section 111 has been in existence, EPA has consistently defined a category of regulated sources, identified the BSER that any individual source can incorporate into its design or operation, and then allowed the states to determine what standards are achievable for each individual source based on that BSER and other factors unique to the source, including the source’s remaining useful life.

In the Proposed Rule, EPA starts by defining for each state a set of mandatory, unchangeable emissions goals and then requires the state to impose whatever is necessary to achieve those goals, leaving the state little, if any, flexibility. Particularly problematic is the rule’s first time reach beyond the individual regulated sources to burden states with imposing obligations on entities with no air emissions.

It is this latter element of the Proposed Rule – reaching beyond the regulated source itself – that constitutes EPA’s most fundamental departure from the law. EPA, in an apparent attempt to rewrite what constitutes a “system of emission reduction” for purposes of section 111, asserts that the BSER for existing EGUs may – or more accurately, must, in light of the emissions

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58 UARG, 134 S. Ct. at 2442.
59 See the UARG Comments.
goals set by EPA for each state, especially Arizona – include measures that would directly or indirectly reduce the utilization of coal-fired plants or measures that are not within the control of the targeted sources.\textsuperscript{60} EPA reaches this novel result by arguing that because “system” is not explicitly defined in the CAA, the agency may for the first time employ an abstract dictionary definition.\textsuperscript{61} EPA then uses this definition to conclude that a “system of emission reduction” can be “virtually any ‘set of things that reduce emissions,’” including everything from “add-on controls...to measures that replace production or generation at the affected sources.”\textsuperscript{62} This is a stunning change in direction that has no basis in the law and should be rejected\textsuperscript{63}

As the Coalition for Innovative Climate Solutions explains in greater detail in its comments, EPA’s novel reinterpretation of the term “system” for purposes of the Proposed Rule cannot withstand scrutiny under the two-step process set forth in Chevron U.S.A., Inc. v. Natural Resources Defense Council, 467 U.S. 837 (1984).\textsuperscript{64} With respect to step one under Chevron, EPA contends that because the term “system” is undefined in section 111, the Agency may for the first time use a new definition in application. This position must fail. The fact that the term “system” is not expressly defined in section 111 suggests at most that Congress has not directly and unambiguously addressed the issue and that EPA’s reinterpretation must instead be examined under Chevron step two.\textsuperscript{65}

When EPA’s new interpretation of “system” is examined under the second step set forth in Chevron, it becomes clear that EPA’s interpretation does not fit “within the bounds of

\textsuperscript{60} Indeed, EPA presumed all coal-fired EGUs within the state of Arizona would shut down by 2020 to meet the interim goal, despite the fact that several Arizona EGUs are less than 10 years old or have had hundreds of millions of dollars spent on retrofits for other EPA requirements within the last 10 years.

\textsuperscript{61} See EPA Legal Memorandum at 51 (defining “system” to be “a set of things working together as parts of a mechanism or interconnecting network; a complex whole”).

\textsuperscript{62} Id. at 51-52.

\textsuperscript{63} The same fundamental flaws exist in EPA’s proposed “alternative approach to BSER,” under which BSER is “in addition to [B]uilding [B]lock 1, the reduction of affected fossil fuel-fired EGU’s mass emissions achievable through reductions in generation of specified amounts from those EGUs.” 79 Fed. Reg. at 34,889; EPA Legal Memorandum at 79 (commenting that under the proposed alternative approach, “the ‘system of emission reduction’ includes reductions in utilization at the affected sources themselves”).

\textsuperscript{64} Under the first step, courts look at “whether Congress has directly spoken to the precise question at issue. If the intent of Congress is clear, that is the end of the matter; for the court as well as the agency must give effect to the unambiguously expressed intent of Congress.” If the court finds that “Congress has not directly addressed the precise question at issue, the court does not simply impose its own construction of the statute . . . . Rather, if the statute is silent or ambiguous with respect to the specific question, the issue for the court is whether the agency’s answer is based on a permissible construction of the statute.” Chevron, 467 U.S. at 842–843.

\textsuperscript{65} See Menkes v. U.S. Dept. of Homeland Security, 637 F.3d 319 (D.C. Cir. 2011) (concluding that statutory text did not resolve question where term at issue was undefined).
reasonable interpretation.” 66 First, sections 111(a) and (d) clearly constrain EPA’s authority in determining BSER. As discussed above, EPA’s own implementing regulations demonstrate the connection between BSER and the sources regulated. 67 Second, EPA’s reinterpretation becomes clearly unreasonable in light of its lack of any defined limit to the Agency’s authority. EPA’s interpretation of “system” in the Proposed Rule would encompass “virtually any ‘set of things’ that reduces emissions.” 68 Such an unprecedented expansion of EPA’s authority without express authorization by Congress cannot withstand scrutiny. 69

Of the four building blocks that make up EPA’s proposed statewide BSER for existing EGUs, only Building Block 1 falls within the scope of measures contemplated by section 111 and could be a foundation for legally defensible emissions guidelines. Building Blocks 2 through 4, however, go far beyond the measures authorized under section 111 and should be withdrawn. 70

5.3 EPA Fails to Provide States with Primacy and Flexibility
Congress clearly intended section 111(d) regulations to employ the same cooperative federalism framework that exists in section 110 of the CAA, giving primacy to the states. 71 Although Congress granted EPA the authority to establish performance standards for new sources under section 111(b), it delegated that authority to the states for existing sources through section 111(d). Section 111(d) thus directs EPA to establish a “procedure” for states to submit plans pursuant to which the state will establish performance standards for existing sources. EPA’s role, therefore, is limited to determining whether the state plan is “satisfactory” and only if the state plan is unsatisfactory may EPA promulgate its own plan. Thus, in crafting section 111, Congress was careful to give EPA no direct regulatory authority over existing sources and limited EPA’s authority to establish substantive standards of performance for

66 UARG, 134 S.Ct. at 2431 (quoting City of Arlington, Tex. v. FCC, 133 S.Ct. 1863, 1868 (2013)).
67 See 40 CFR § 60.22(b)(5) (requiring EPA to issue an “emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities”).
68 EPA Legal Memorandum at 51.
69 See CICS comments at section III.B for a more detailed analysis. The CICS comments are summarized here and incorporated by reference.
70 As UARG addresses in its comments, the Proposed Rule also attempts to impermissibly impose federally enforceable obligations on a broad class of “affected facilities” beyond the regulated category of existing EGUs. Because nothing in the CAA authorizes EPA or the states to impose obligations on any entity other than a source listed in the source category, EPA should abandon this approach.
71 See CAA § 111(d)(1) (requiring EPA “to establish a procedure similar to that provided by section [110]...under which each State shall submit to [EPA] a plan which...establishes standards of performance for any existing source” within the state).
existing sources to the limited situations where a state fails to act. EPA recognized this division of responsibilities in 1975 when it promulgated the Subpart B regulations.\footnote{72}{40 Fed. Reg. at 53,343 (noting that “states will have primary responsibility for developing and enforcing control plans under section 111(d)”)}

Congress further provided that states are to be given broad discretion to develop their section 111(d) plans and to implement them based on specific state concerns and needs. Although courts have not yet addressed specifically EPA’s review of state plans under section 111(d), because that section calls for EPA to review state plans in a manner similar to section 110 State Implementation Plans, decisions under section 110 are instructive. Under those decisions, it becomes clear that under section 111(d), EPA must approve such state plans unless they are arbitrary or capricious.\footnote{73}{See, e.g., Luminant Generation Co. v. EPA, 675 F.3d 917, 920 (5th Cir. 2012) (EPA’s role in approving state plans is “confine[d] . . . to the ministerial function of reviewing [state plans] for consistency with the Act’s requirements”).}

Specifically, section 111(d) anticipates that states will consider the remaining useful lives of facilities subject to regulation and provides the states significant freedom to consider “other factors” as well in developing the state plan.\footnote{74}{CAA § 111(d)(1)(B) (“Regulations of the Administrator under this paragraph shall permit the State 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”) (emphasis added). See also CAA § 111(d)(2) (in situations where EPA is responsible for a plan and applicable standards of performance, “the Administrator shall take into consideration, among other factors, remaining useful lives of the sources in the category of source to which such standard applies”) (emphasis added).}

Taking into account these various factors, states may then grant individual sources longer periods of time to comply or may apply less stringent standards to a specific source or sources than EPA has set forth in the emission guidelines. This is consistent with EPA’s own acknowledgement that “[s]tates will be free to vary from the levels of control represented by the emission guidelines...In most if not all cases, the result is likely to be substantial variation in the degree of control required for particular sources, rather than identical standard for all sources.”\footnote{75}{40 Fed. Reg. at 53,343.}

EPA has no discretion to deviate from the clear statutory terms or to eliminate the states’ ability to consider remaining useful life in setting and, as appropriate, relaxing standards of performance for a facility.\footnote{76}{See. Chevron, 467 U.S. at 842 (when Congress “has directly spoken to the precise question at issue,” the court interprets and applies the statutes without deferring to an agency interpretation). See also CICS Comments at section III.C (addressing both that the Proposed Rule improperly usurps state authority to consider remaining useful life, among other factors, in setting performance standards, and that EPA arbitrarily and capriciously ignores the practical need to taking remaining useful life into consideration).} Although EPA argues that the Proposed Rule provides states with flexibility, the Proposed Rule instead effectively dictates all key policy choices that should have been left to the states. EPA’s
Proposed Rule sets inflexible CO₂ emission intensity caps for each state that effectively dictate the form and content of the performance standards for the states. 77 This is not what Congress envisioned. Section 111(d) provides that standards of performance are to be set by the states and must apply to sources. 78 It is difficult to see how the approach set out in the Proposed Rule implements the cooperative federalism the CAA embodies.

EPA’s interim and final goals for Arizona present one of the best examples of this lack of flexibility. As EPA presumes, and various analyses demonstrate, Arizona will have to close almost all coal units to achieve the interim and final targets set by EPA for Arizona under the Proposed Rule. Compliance with EPA’s proposed rule would effectively preclude Arizona from taking into account a facility’s remaining useful life. For SRP, that is a significant and unreasonable burden. At least one of SRP’s facilities – SGS Unit 4 – came on line only five years ago at a cost of $1 billion. And, earlier this year, SRP completed the installation of approximately $470 million in new emission controls at CGS.

This lack of flexibility also was highlighted by comments submitted to EPA by ADEQ. In its analysis, ADEQ found that:

“[T]he more Arizona relies on Building Blocks 3 and 4 to achieve compliance with the final goal of 702 lbs CO₂/MWh, the farther it gets from compliance with the interim goal (scenarios 2-4). Conversely, if Arizona designs its program to comply with the interim goal, it ends up with a final rate that is far lower than necessary to comply with the final standard and ends up preserving a much smaller portion of its existing coal-fired generation resources (scenario 5).

In fact, Arizona has no flexibility to shift from one Building Block to another to meet its rate-based goal under the program as proposed. The state cannot increase reliance on Building Block 1, because the rate-based goal assumes zero coal generation, and the interim goal...prevents Arizona from increasing reliance on Building Block 3 or 4 to preserve coal generation. If no coal generation remains in 2020, increasing the efficiency of coal units will obviously have no effect on Arizona’s rate. Arizona cannot increase reliance on Building Block 2, because the interim goal effectively requires the maximum redispacth possible.” 79

77 Fed. Reg. at 34,953; proposed 40 C.F.R. § 60.5765. Tbl. 1.
78 CAA § 111(d)(1) (“...each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source...”)
A fundamental element of section 111(d) is that the states will have flexibility to develop performance standards that best address specific state factors. Thus, while EPA may require states to submit plans that contain performance standards, EPA may not dictate the form and content of those standards, unless a state fails to submit an acceptable plan.80 And yet that is precisely what EPA has done in the Proposed Rule. For that reason, the Proposed Rule must be withdrawn.

5.4 EPA Unlawfully Usurps Authority Given to FERC, the States, and SRP’s Board of Directors under the Federal Power Act and the Tenth Amendment

EPA’s proposal violates a host of federal, state, and local laws governing the electric utility industry by seeking to step into matters not only reserved to a sister federal agency – FERC – but also into matters expressly left to the control of state, municipal, or other local bodies, such as the SRP Board of Directors (SRP Board).81 Such “an enormous and transformative expansion in EPA regulatory authority without congressional authorization” certainly could not have been contemplated when section 111(d) of the CAA was enacted.82

The Tenth Amendment to the United States Constitution declares that “[t]he powers not delegated to the United States by the Constitution, nor prohibited by it to the States, are reserved to the States respectively, or to the people.” Before Part II of the Federal Power Act (FPA) was enacted in 1935, states pervasively regulated utilities within their borders based on general police powers. Congress adopted Part II of the FPA only after the U.S. Supreme Court held that states could not regulate interstate sales of electricity under the Commerce Clause.83

Even then, Congress limited federal regulation through FERC to interstate transmission and interstate wholesale sales of electric energy and preserved to the states their traditional authority over electric generating facilities, local distribution, retail sales of electricity, and intrastate transmission.84 Congress further limited the applicability of the FPA such that it generally exempts the United States and federal agencies, states and municipalities, and their agencies, and most rural electric cooperatives from FERC regulation even in the limited areas in

80 CAA § 111(d)(2)(A).
81 Both UARG and the American Public Power Association (APPA) provide a detailed and thorough discussion of the history of electric utility regulation under the Federal Power Act, as well as of EPA’s unlawful intrusion into matters Congress reserved to FERC or to state, municipal, or other local bodies. See UARG Comments and APPA Comments. SRP will not repeat that detailed discussion but instead incorporates the UARG and APPA comments by reference and highlights the key points here.
84 16 U.S.C. § 824(b).
which FERC may exercise regulatory authority.\textsuperscript{85} Instead, these public power entities generally are subject to pervasive oversight by state, municipal, or other local bodies.\textsuperscript{86}

SRP is an agricultural improvement district organized under Arizona state law.\textsuperscript{87} SRP is a political subdivision and is governed by the SRP Board, a publicly elected board of directors tasked with SRP governance and regulation.\textsuperscript{88} The powers delegated to the SRP Board are established by statute.\textsuperscript{89} The SRP Board serves as SRP’s regulatory body and has the exclusive authority to carry on the business of SRP, including establishing electric prices.\textsuperscript{90} The SRP Board may establish and enforce by-laws, rules, and regulations necessary to carry on SRP’s business and may, among other things, construct facilities for the generation and delivery of electricity.\textsuperscript{91}

Pursuant to its authorities under state law, and reflecting SRP’s obligations to its customers, the SRP Board adopted Pricing Principles in December 2000. These principles guide the pricing of SRP’s electric service and are used to develop price plans and associated policies. Key elements of the SRP Board’s policy include the following:\textsuperscript{92}

- \textit{Gradualism} – to enhance sound, economic decision-making by customers of all types through stabilizing price levels and smoothing the impact of cost movements that may be caused by temporary factors.

- \textit{Cost Relation} – to establish prices in relation to costs and SRP’s stewardship to its water constituents, and thus not to pursue the maximization of “profit.”

\textsuperscript{85} 16 U.S.C. § 824(f).

\textsuperscript{86} In \textit{Pacific Gas & Electric Co. v. State Energy Resources Conservation and Development Comm’n}, 461 U.S. 190 (1983), the Supreme Court emphasized that federal regulation by agencies other than FERC may not invade the domain that the Federal Power Act has preserved for the states. In that decision, the Court explained that states have “\textit{traditional authority over the need for additional generating capacity, the type of generating facilities to be licensed, land use ratemaking, and the like.” Id. at 212 (concluding that federal regulation of the safety of nuclear power plants did not override “\textit{the regulation of electricity production}” by the states).

\textsuperscript{87} See A.R.S. §§ 48-2301 through 48-2475.


\textsuperscript{89} A.R.S. §§ 48-2335 through 48-2338.

\textsuperscript{90} As a public power entity created by state law, SRP is not regulated by the Arizona Corporation Commission (ACC) except in limited circumstances not relevant here. Neither FERC nor the ACC – nor EPA or ADEQ – have the authority to regulate SRP’s generation resource mix or to establish requirements for renewable energy or energy efficiency programs. Those decisions rest exclusively with the SRP Board, which works with SRP management to develop and set policy for SRP.

\textsuperscript{91} A.R.S. §§ 48-2335, -2336, -2340, and -2341(B).

\textsuperscript{92} Minutes of the December 4, 2000 SRP Board meeting are available from the SRP Secretary’s Office.
• **Choice** – to constantly improve customer satisfaction through the creative design of pricing structures that reflect customers’ different desires or abilities to manage the consumption, assume more price control, or demand differentiated products and services, among others.

• **Equity** – to treat customers of all types in an economically fair manner.

• **Sufficiency** – to recover the cost of, and to invest and reinvest in a system of assets to perform its policy obligations, including its obligation to store and deliver water to the owners of land within the boundaries of the Salt River Reservoir District, to maintain SRP’s financial well-being, and to follow the foregoing principles.

In addition, consistent with these principles and its obligations to SRP’s customers, the SRP Board took a reasoned approach to the integration of renewable resources and energy efficiency into the SRP system, establishing Sustainable Portfolio Principles and setting a goal for SRP to meet 20% of its retail electricity requirements through sustainable resources by 2020. Currently, SRP is ahead of schedule — in FY2014, 12.8% of SRP’s retail requirements were met with sustainable resources and more than 25% of the energy produced by SRP’s resources had no associated GHG emissions.

Moreover, the SRP Board continually evaluates ways to expand SRP’s use of environmentally sensitive supply- and demand-side options, explores additional ways to displace the use of fossil fuels, and provides opportunities for the introduction of new technologies and ideas. As mentioned in Section 2 of these comments, SRP has recently been working to further enhance the company’s commitment to carbon reductions through the development of an IRP. This collaborative process was initiated in early 2014 and has included extensive stakeholder engagement to produce a resource planning path to support a reduction in the GHG intensity of SRP’s electric generation resources.

EPA’s Proposed Rule unreasonably interferes with – if not completely usurps – not only the responsibilities delegated for FERC under the FPA, but also the responsibilities reserved to the state utility regulators and to SRP’s Board. Through the Proposed Rule, EPA effectively will limit the SRP Board’s ability to implement appropriate and balanced resource planning, incorporate renewable energy and energy efficiency programs into SRP’s resource mix in a reasonable manner, and, ultimately, manage the rates charged to SRP’s customers. These are issues and

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94 See UARG Comments and APPA Comments.
policies reserved to SRP’s Board. The Proposed Rule is overreaching and would seize more authority than the CAA grants to EPA under section 111(d). For this reason, EPA should withdraw the Proposed Rule.  

5.5 EPA May Not Regulate EGUs Simultaneously Under Sections 111(b) and 111(d) of the CAA

For the first time, and contrary to its longstanding practice under section 111 of the CAA, EPA proposes to regulate existing sources that modify or reconstruct under both the existing source (section 111(d)) and the new source (section 111(b)) provisions of the CAA. Under section 111 of the CAA, the definitions of “existing” source and “new” source are mutually exclusive. Section 111(a)(6) defines an “existing source” as “any stationary source other than a new source.” Thus, an “existing source” is one that has commenced construction before the publication of regulations or proposed rules applicable to new sources of the same type. Such “existing sources” are subject to regulation under section 111(d).

On the other hand, section 111(a)(2) defines a “new source” as “any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.” Thus, a “new” source may come into existence either through new construction or through modification or reconstruction of what otherwise would be an existing source provided the construction, modification, or reconstruction commences after publication of regulations or proposed rules applicable to such sources. Such “new sources” are subject to regulation under section 111(b).

The critical fact then is that once an existing source is modified or reconstructed, it ceases to be an existing source subject to section 111(d) and becomes a new source subject to 111(b). Under the CAA, a source is either “existing” or it is “new”; it cannot be both at the same time. Moreover, under its explicit terms, section 111(d) may not apply to sources subject to section

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95 As discussed in more detail by UARG, these same fundamental flaws extend to EPA’s proposed “alternative approach to BSER,” under which BSER is, “in addition to [B]uilding [B]lock 1, the reduction of affected fossil fuel-fired EGUs’ mass emissions achievable through reductions in generation of specified amounts from those EGUs.” 79 Fed. Reg. at 34,889 (emphasis added); EPA Legal Memorandum at 79. See UARG Comments, for an extensive discussion of the regulatory responsibility reserved to the state and local governmental entities over the generation of electricity and resource planning.

96 See, e.g., 79 Fed. Reg. at 34,974 (“existing sources that are subject to requirements under an approved CAA section 111(d) plan would remain subject to those requirements after undertaking a modification or reconstruction”).

97 CAA § 111(a)(6) (emphasis added).

98 CAA § 111(a)(2) (emphasis added).
111(b). Because EPA's proposal ignores this clear statutory language, the Proposed Rule must be withdrawn and reproposed to conform to the clear statutory language of CAA section 111.
6. SRP CONCERNS WITH EPA'S BSER DETERMINATION

In addition to the legal infirmities associated with EPA’s approach to BSER, discussed in Section 5 of these comments, SRP believes the BSER determination is technically flawed, as discussed in more detail below and in Appendix F of these comments.

6.1 EPA Failed to Show Its Proposed “System” is BSER

EPA has failed to show that its proposed “system” is the “best system,” by its own criteria, because EPA did not properly consider all GHG emissions in evaluating the amount of GHG emissions reductions produced by the “system.”

EPA claims that the term “system” is defined broadly as “a set of things working together as parts of a mechanism or interconnecting network.” Yet, even if this definition were an appropriate definition for “system” under the CAA, which it is not, EPA ignores this ordinary meaning, and the statutory mandates, legislative history, and its own criteria in defining its “best system.”

For example, EPA did not engage in a holistic analysis of the benefits and costs of switching to greater NGCC use under the BSER’s Building Block 2. First and foremost, Building Block 2 is not premised on emissions reduction – it encourages one component of the “system” to emit more. Furthermore, EPA, in imposing this building block, focuses only on the end of the system rather than considering a complete life cycle assessment to determine the effect of including Building Block 2 in its “best system.” In doing this, EPA does not satisfy the agency’s second criteria for defining a “best system” – considering an accurate estimate of the GHG emissions reductions to the atmosphere that can result from the system.

EPA uses its IPM analysis to predict an increase in natural gas use by 2020 with a corresponding expansion in the natural gas development infrastructure. Then, EPA predicts that natural gas use will decline below baseline levels 10 years later. Yet, EPA has not explained how natural gas producers will re-capture the costs of infrastructure expansion conducted over the first 10 years of the 111(d) program and why developers would suddenly abandon this increased capacity. Logic dictates that they would not. Once capacity expands, that capacity will be used, if not domestically, then through foreign exports. Accordingly, EPA’s GHG emissions assessment, which assumes declining upstream GHG emissions in the later years of its

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100 EPA points to no legislative history to support its assertion that Congress intended such a broad definition of system. To the contrary, given Congress’ disappointment with EPA’s implementation of the provision in 1997, and its focus on add-on controls, it is reasonable to assume that “system” relates to physical methods that result in emissions reductions at the affected facility, and not displacement or reallocation of production to other emissions sources.
“system,” is not reliable because it does not account for how producers will use the expanded natural gas infrastructure constructed in the early years of the program.

Moreover, if EPA and the states implement 111(d) in accordance with EPA’s current proposal, there is a high probability that the carbon footprint associated with both coal and natural gas generation will increase due to greater GHG emissions associated with fuel extraction and delivery, driven by future export of coal for use by other countries and increased use of natural gas both domestically and internationally. EPA readily admits that it omitted significant GHG emissions sources from its analysis:

“Not included are vented and fugitive CO₂ emissions from natural gas systems, such as vented CO₂ emissions removed during natural gas processing, or energy-related CO₂ such as emissions from stationary or mobile combustion.”

In addition, natural gas exploration and drilling activities can produce a large quantity of GHG emissions in the form of methane – a more potent GHG than CO₂.

In conducting its upstream GHG impacts assessment, EPA’s Risk Impact Analysis (RIA) explains that EPA used the methodology developed for the Sixth U.S. Climate Action Report to estimate upstream impacts of its “system.” But, other than stating that this methodology underwent public review, EPA provides no explanation on why the Agency selected this particular methodology. Indeed, EPA recommended use of a different approach in comments to FERC:

“We recommend that FERC establish reasonable spatial and temporal boundaries for the analysis of GHG emissions, and that the FEIS [Federal Environmental Impact Statement] quantify and consider the lifecycle GHG emissions associated with the proposed action. The methodologies for conducting that analysis are available and well developed; FERC could draw on good examples of lifecycle GHG emissions done in NEPA [National Environmental Policy Act] analyses by other federal agencies....We recommend the FEIS consider the extent to which the implementation of the proposed project could increase the demand for domestic natural gas extraction; as well as the environmental impacts associated with the potential increased production of natural gas.”

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101 Risk Impact Analysis at 144.

102 See Memorandum from Debra A. Griffin, Associate Director, Compliance Assurance and Enforcement Division, Region 6 U.S. EPA to Kimberly D. Bose, Federal Energy Regulatory Commission (Mar. 3, 2014).
Moreover, others have undertaken more complete lifecycle analyses that include contributions from transportation.\(^{103}\) In the absence of an explanation on how EPA selected its methodology over other available approaches, EPA’s selection is arbitrary and capricious, and lacking in completeness – making all of its GHG emissions estimates unreliable.

EPA’s proposal contains a significant void because it fails to consider both emissions decreases and increases in its “system” assessment. Accordingly, EPA has not shown that its proposed “system” satisfies its second criteria for defining the “best system.”

6.2 EPA Did Not Properly Account for Non-Air Quality Health, Environmental, and Other Impacts

Like EPA’s GHG emissions reductions assessment, EPA’s environmental, energy and other factors assessment fails to meet Congress’ documented expectations for a “system.” The definition of “standard of performance” requires that the Administrator consider non-air quality health and environmental impacts and energy requirements before determining that a “system” qualifies as the best. Legislative history also makes clear Congress’ expectations with regards to defining a system:

“This Administrator should take into consideration all of the processing steps performed on a material from its natural state through to final usage in determining the requirements under this section for a technological continuous emissions reduction system.”\(^{104}\)

“The term ‘best system’ necessarily involves consideration of factors such as water and land impacts of the system.” And, “new technology should not be encouraged if it would solve one pollution problem by creating a greater one.”\(^{105}\)

After reviewing the Proposed Rule’s preamble, the following appears to represent the sum total of statements the Administrator makes with regards to these considerations:

- Heat-rate improvements cause fuel to be used more efficiently, reducing the volumes of, and therefore the adverse impacts associated with disposal of, coal combustion solid waste products.

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\(^{104}\) Clean Air Act Amendments of 1977, Committee on Interstate and Foreign Commerce; Report No. 95-294 at 189, (May 12, 1977).

\(^{105}\) Id. at 197.
• Coal combustion for electricity generation produces large volumes of solid wastes that require disposal, with some potential for adverse environmental impacts; these wastes are not produced by natural gas combustion.

• NGCC units generally require less cooling water than steam EGUs.

• Generation from wind turbines does not produce solid waste or require cooling water, a better environmental outcome than if that amount of generation had instead been produced by a typical range of fossil fuel-fired EGUs.

• Nuclear poses unique waste disposal issues (although avoids the solid waste issues specific to coal-fired generation). EPA does not consider that potential disadvantage of nuclear generation relative to fossil fuel generation as outweighing nuclear generation’s other advantages as an element of Building Block 3.

• Demand-side energy efficiency avoids the non-air health and environmental effects of the fossil fuel-fired generation for which it substitutes.

It is unclear whether EPA fully assessed the impacts associated with the changes in energy resources that would occur under the agency’s section 111(d) proposal. EPA should not proceed to finalize existing source performance standards until the agency conducts a thorough impact assessment and allows for public comment on its proposed conclusion.

6.3 EPA Improperly Includes GHG Emissions Reductions from RPS and EES

EPA improperly includes GHG emissions reductions from Building Blocks 3 and 4 in assessing the GHG emissions reduction potential of its “system.” With regards to RPS, EPA states in the preamble and the rule’s supporting documents that:

“EPA does not expect this anticipated expansion to fall outside the historical norms of deployment or to create unusual pressures for cost increases.”106

In other words, EPA’s system will not alter the current course for RPS deployment. Similarly, EPA notes that:

“Every state has established demand-side energy efficiency policies, and many stakeholders emphasized the success of these policies in reducing electricity consumption by large amounts.”107

107 Id. at 34,871.
These statements suggest GHG reductions from these RPS and EE programs would occur without EPA’s current proposal. This in turn clouds EPA’s reliance on Building Blocks 3 and 4 as part of the agency’s “system” of emissions reduction. That is, these emissions reductions do not result from the “system,” and EPA has not offered evidence showing otherwise. Yet, EPA’s cost/benefit analysis for the Proposed Rule relies on inclusion of these reductions in its system to justify its “best system.” In doing so, EPA presents an incomplete assessment of the benefits and costs created by the “system.”
7. **SRP CONCERNS WITH “BUILDING BLOCKS” USED BY EPA TO CONSTRUCT INTERIM AND FINAL STATE GOALS**

SRP has significant concerns with assumptions made by EPA under each of its proposed building blocks, as discussed in detail below.

7.1 **Building Block 1 – Heat Rate Improvements**

With this building block, EPA focuses on reduction of the carbon intensity of generation at individual affected units through heat rate improvements. EPA identifies two principle areas of opportunity: 1) heat rate improvements that can be achieved by reducing heat rate variability at individual coal-fired units through adoption of best practices for operation and maintenance; and 2) heat rate improvements that can be achieved through equipment upgrades.

EPA identifies “best practices” to include: turning off unneeded pumps at reduced loads, installing digital control systems, more frequent tuning of existing control systems, or earlier like-kind replacement of worn existing components. EPA bases its proposal on the assumption that these activities will produce an aggregate heat rate improvement of 4%. From an equipment upgrade perspective, EPA evaluates potential opportunities to improve heat rates at affected units through specific upgrades identified in a 2009 study prepared by Sargent & Lundy (S&L). EPA bases its proposal on the assumption that these upgrades will achieve an additional heat rate improvement of approximately 2%. Taken together, EPA believes heat rate improvements from adoption of best practices to reduce heat rate variability and implementation of equipment upgrades can produce a total improvement of 6%.

EPRI and NERC have expressed concerns about the validity of EPA’s approach in establishing the 6% reduction requirement. NERC expressed concern “…that the assumed improvements may not be realized across the entire generating fleet since many plant efficiencies have already been realized and economic heat rate improvements have been achieved.”

EPRI indicated that:

> “Estimates of heat rate improvements at existing coal EGUs are very dependent on individual unit characteristics (age, design, maintenance history, type of coal, etc.) and are difficult to apply a national fleet-wide heat rate goal. In estimating mitigation potentials, EPRI recommends that the estimates should be based on current studies and data that take into account recent EPA environmental control regulations. Regional or state-specific research and data should be used for the basis for estimating potential heat rate improvements rather than use of a...”

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108 NERC, *Reliability Impacts Potentially Resulting from the CPP*; November 2014; at 2.
national average for all. States differ widely in the characteristics and operating performances of their respective generating fleets.”

There is uncertainty that Building Block 1 would have a role in Arizona’s compliance plan under 111(d) because of the aggressive assumptions for redispatch applied by EPA to Arizona’s goals under Building Block 2. However, SRP presumes that EPA will respond to commenter concerns regarding application of Building Block 2, and therefore submits the following comments addressing EPA’s Building Block 1 assumptions.

SRP is concerned that EPA has not substantiated that further heat rate improvement “has been adequately demonstrated” at the levels included in the proposal for the units that will be subject to the Proposed Rule. SRP disagrees with EPA’s legal interpretation that the agency has authority to specify the level of emissions reductions achievable through the “best system,” but even if EPA’s interpretation were proper, EPA must provide an opportunity for public comment on a corrected analysis of the emissions reductions achievable through heat rate improvements before the Agency can require states to consider any specific level of heat rate improvement in their plan submissions.

Furthermore, EPA has not accounted for the impacts other aspects of this Proposed Rule will have on an EGU’s ability to achieve the level of heat rate improvements contemplated by EPA. For example, using NGCC generation in place of coal generation will further degrade heat rate performance of remaining coal units because it is expected these units will operate at lower loads, which has a negative impact on heat rate.

(a) EPA Assumptions Regarding Reduction in Heat Rate Variability
EPA states it has independently analyzed the improvements in gross heat rate that can be achieved by reducing variability in gross heat rate through adoption of best practices for operation and maintenance at each of the twelve coal-fired EGUs in Arizona. However, EPA did not take these unit-specific analyses into account in reaching a conclusion regarding the improvements in gross heat rate that could be achieved by reducing variability in gross heat rate through adoption of best practices for operation and maintenance at the coal-fired EGUs in Arizona. Instead, EPA based its assumption of what is achievable for the coal-fired EGUs in Arizona on the results of its analysis for a larger “study population” of 884 coal- and petroleum coke-fired EGUs. Thus, EPA’s results are indicative only of the improvements in gross heat

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109 EPRI Comments at 3.
rate which may be achievable for the “study population” as a whole; they did not consider what unit-specific improvements have already been completed or which specific improvements might be available at the coal-fired EGUs in Arizona.

SRP concerns regarding EPA’s analysis are summarized below. More detailed information regarding these concerns is found in the attached memorandum from RTP Environmental Associates (see Appendix G of these comments).

- EPA based its analysis on variability in hourly heat input, not on variability in hourly gross heat rate. Variability in heat input is not a measure of efficiency.

- EPA miscalculated the data distribution for certain units and certain load/temperature bins, resulting in substantial overestimation of the variability in heat input.

- EPA’s analysis, which corrects for ambient temperature and gross load, does not correct for a sufficient number of factors to reflect variability that might reasonably reflect an opportunity to improve heat rate through improved operating practices.

- EPA erroneously labels any differences in hourly heat input that are observed in the data set for a particular EGU and that cannot be explained by differences in capacity factor or ambient temperature as “heat rate variability.” EPA assumes that this heat rate variability is “attributed to operation and maintenance practices” and is indicative of a “potential for heat rate improvement.” In other words, EPA assumed that each operating hour for which a particular EGU’s heat input is greater than the heat input during other operating hours for that EGU with similar ambient temperature and capacity factor, represents an opportunity to improve upon the EGU’s performance during that hour. This assumption is not valid, as EPA’s analysis did not attempt to take measurement error, and the potentially significant effects of this error, into account.

- EPA’s data set is inappropriate, as it includes units that are not among those that would be subject to the Proposed Rule, such as the units at the Navajo Generating Station (NGS) and Unit 4 at the Sundt Generating Station. Variability in hourly heat input or gross heat rate at units that will not be subject to the Proposed Rule is not indicative of an opportunity for heat rate improvement at coal-fired EGUs that would be subject to the Proposed Rule.

EPA’s inferences with respect to a causal relationship between high variability in calculated hourly gross heat rate data and poor heat rate performance are without

\[112 Id. at 2-15 and 2-27.\]
foundation. EPA observes a positive statistical correlation between the level of variability in calculated hourly gross heat rate data and annual gross heat rate (i.e., a negative correlation between variability and efficiency). From this observation, EPA draws a critical inference regarding causal relationship:

“These results indicate that, other factors held equal, if an EGU reduces heat rate variability, generally heat rate performance will improve.”\(^{113}\)

However, the “heat rate variability” upon which EPA heavily relies is not necessarily an indicator of actual changes in heat rate performance. To at least an extent, this observed correlation is an indicator that units with better heat rate performance may have more accurate 40 CFR Part 75 monitoring systems, or are using alternate measurement methods allowed under 40 CFR Part 75. While a laudable goal, improving the performance of Part 75 monitoring systems is not a viable method of reducing CO\(_2\) emissions.

Furthermore, EPA’s assumptions regarding the magnitude of improvements in gross heat rate achievable through adoption of best practices for operation and maintenance are invalid. EPA assumes that heat rate improvements are achievable through “practices such as turning off unneeded pumps at reduced loads, installation of digital control systems, more frequent tuning of existing control systems, or earlier like-kind replacement of worn existing components.”\(^{114}\)

Although it is true that these practices may improve heat rate performance at a given EGU at which they have not already been implemented, EPA has provided no data or information that connects these practices to its assumptions regarding achievability, costs, and overall reasonableness of improvements in gross heat rate. Instead, EPA’s estimate of a 4% across-the-board improvement reflects nothing more than an arbitrary fraction of the variability in hourly heat input which EPA believes it has observed in the data set for its “study population.”

“Assuming that between 10 percent and 50 percent of the deviation from top decile performance in each subset of hourly heat rate observations within defined ranges of temperature and load could be eliminated through adoption of best practices, the result is a corresponding estimated range of 1.3 percent to 6.7 percent technical potential for improvement in the average heat rate of the entire fleet of coal-fired EGUs. Based on this analysis, we believe a reasonable estimate for purposes of developing state-specific goals is that affected coal-fired steam EGUs on average could achieve a four percent improvement in heat rate

\(^{113}\) Id. at 2-28.

\(^{114}\) 79 Fed. Reg. at 34,860.
through adoption of best practices to reduce hourly heat rate variability. This estimate corresponds to the elimination, on average across the fleet of affected EGUs, of 30 percent of the deviation from top-decile performance in the hourly heat rate for each EGU not attributable to hourly temperature and load variation.\textsuperscript{115}

In addition to the analysis of hourly data discussed above, EPA offers another explanation for its assumption that 4% improvement in gross heat rate is achievable, based on a more simplistic analysis of data for the same “study population.”

“[I]f each unit achieved heat rate performance equal to its best three-year moving average, the study population as a whole would post a 3.9% heat rate improvement.”\textsuperscript{116}

This explanation is similar to, but even less technically supportable than, the first. One example involving a unit at which a change in coal source was implemented will illustrate the problem with EPA’s conclusion. At CGS Unit 2, which SRP owns and operates, the average gross heat rate from 2004 through 2006 was 9,257 British thermal units per kilowatt-hour (Btu/kWh), the best three-year average for this EGU during EPA’s study period. Following a switch to Powder River Basin (PRB) coal, the average gross heat rate from 2007 through 2011 was 9,827 Btu/kWh. This represents an increase in gross heat rate of approximately 6%, at least in part due to the higher moisture content of PRB coal.

The only sensible conclusions that can be drawn from these data with respect to Building Block 1 are that switching to a high-moisture coal, such as PRB coal, causes an increase in heat rate, which can be reversed by switching to a low-moisture coal. EPA incorrectly characterizes this change as “heat rate variability” which can be reversed through “practices such as turning off unneeded pumps at reduced loads, installation of digital control systems, more frequent tuning of existing control systems, or earlier like-kind replacement of worn existing components.”\textsuperscript{117}

Having failed to identify the cause of the increase in heat rate (switching to PRB coal) and the potentially available method of reversing it (switching to low-moisture coal), EPA fails to assess the economic and non-GHG environmental impacts of this technique for improving heat rate.

The flawed analysis described above is critical to EPA’s conclusions with respect to reductions in CO\textsubscript{2} emissions achievable under Building Block 1. The goal computation must be corrected to

\textsuperscript{115} 79 Fed. Reg. at 34,860 (internal footnote omitted).


\textsuperscript{117} 79 Fed. Reg. at 34,860.
remove the effect of unsupported assumptions regarding improved heat rate performance achievable through implementation of best practices for operation and maintenance of coal-fired EGUs.

(b) **EPA Assumptions Regarding “Best Practices”**

In addition to its analysis of variability in hourly heat input rate and gross generation data for the “study population,” EPA also asserts that the 2009 S&L study supports its conclusion regarding the achievability of improvements in heat rate at coal-fired EGUs at no cost or low cost. EPA specifically cites the following nine practices discussed in the study:

- Condenser cleaning;
- Intelligent soot blowers;
- Electrostatic precipitator modification;
- Boiler feed pump rebuild;
- Air heater and duct leakage control;
- Neural network;
- SCR system modification;
- Flue gas desulfurization system modification; and
- Cooling tower advanced packing.

SRP commissioned S&L to evaluate the opportunities for heat rate improvements, through these and other techniques, at the two coal-fired EGUs at its CGS. S&L’s analysis and approach is consistent with the same effort they performed in which EPA concluded 4% was reasonable. Contrary to EPA’s interpretation of S&L’s 2009 study, the results of the CGS study, which is included as Appendix H of these comments, indicate there are no opportunities to improve heat rate through implementation of “best practices.” S&L also performed this analysis for the 4 units at SGS, which is included as Appendix I of these comments. Similar to the CGS analysis, 3 of the 4 units at SGS do not have any opportunities to improve heat rate.

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EPA Assumptions Regarding Equipment Upgrades

In the preamble to the Proposed Rule, EPA identifies only one source of information as the basis for its conclusions regarding heat rate improvements through equipment upgrades:

“For the equipment upgrade analysis, we evaluated potential opportunities to improve heat rates at affected EGUs through specific upgrades identified in the 2009 Sargent & Lundy study. In that study, Sargent & Lundy estimated ranges of potential heat rate improvement achievable through a variety of equipment upgrades...We screened the upgrades from the study to identify what we consider to be a reasonable subset of equipment upgrades that would generally be beyond the scope of investments we would expect to be made for purposes of achieving the best-practices heat rate improvements discussed above. Based on the average of the study’s ranges of potential heat rate improvements from the various upgrades in this subset, implementation of the full subset of appropriate opportunities at a single EGU could be expected to result in an aggregate heat rate improvement of approximately four percent (incremental to the improvement achievable from adoption of best practices).”

The inferences drawn by EPA from the 2009 S&L study regarding aggregate heat rate improvement are inappropriate, for at least two reasons. First, the numbers presented in the study did not reflect any analysis of improvements actually achieved or determined to be achievable at any particular EGU.

“Heat rate improvements described in the 2009 Report case studies were estimated at a conceptual level, and were not based on any site-specific detailed analysis. In addition, verification of actual heat rate improvements was not made to determine whether any of the modifications were implemented and what actual heat rate improvements were realized based on detailed design.”

Second, EPA initially assumes that the heat rate improvements that may be achievable at a hypothetical EGU at which those improvements have not already been made are informative as to the achievable improvements in heat rate for the fleet of twelve coal-fired EGUs in Arizona. EPA recognizes and acknowledges that this assumption has no basis “because the EPA expects

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120 Unit Heat Rate Improvement Study at Coronado Generating Station SL-012487 (Nov. 13, 2014). Sargent & Lundy. (Included as Appendix H of these comments.)
that a significant fraction of the coal fleet has already applied some or many of the available [heat rate improvement] methods.\textsuperscript{121}

EPA has broad authority to gather information for the purpose of carrying out its responsibilities under the CAA,\textsuperscript{122} and frequently exercises that authority for purposes of collecting information from entities potentially subject to a new regulation.\textsuperscript{123} However, in this instance, EPA chose to forgo a search for relevant data to support its analysis.

“The EPA has found no comprehensive data set on the extent to which specific [heat rate improvement] methods have already been applied at individual EGUs. The EPA believes that many EGU owners consider such information to be confidential.”\textsuperscript{124}

Instead, EPA proceeds to establish emission guidelines for Arizona and other states, believing it can compensate for the absent unit-specific data by cutting in half the unrepresentative estimate generated by the agency using generic data.

“[W]e recognize that this total may overstate the average equipment upgrade opportunity across all EGUs because EGUs may have already implemented some of these upgrades. We therefore propose to use as a data input for purposes of developing state goals an estimate that, on average across the fleet of affected EGUs, only half of the full equipment upgrade opportunity just described remains—i.e., that for the fleet of affected EGUs as a whole, the technical potential for heat rate improvements from equipment upgrades incremental to the best-practices opportunity is on average two percent rather than four percent.”\textsuperscript{125}

A review of pertinent data for Units 1 and 2 at CGS illustrates the type of information that EPA would have collected had it undertaken the data-gathering that is crucial for reasoned decision-making. First, EPA would have seen that SRP already performed several of the equipment

\begin{footnotesize}
\begin{enumerate}
\item See Docket No. EPA-HQ-OAR-2013-0602-17180, GHG Abatement Measures, at 2-36.
\item 42 U.S.C. § 7414(a).
\item See, e.g., Supporting Statement for EPA Information Collection Request No. 2411.01 (Mar. 23, 2011). Available at http://www.reginfo.gov/public/do/DownloadDocument?documentID=227374&version=2, providing EPA’s estimated cost burden of 66,000 hours and $29 million to be imposed on regulated entities for responding to the information request and citing as justification EPA’s conclusion “that obtaining updated information will be crucial to informing its decisions [regarding emission standards under Clean Air Act § 111 and § 112] for petroleum refineries.”
\item 79 Fed. Reg. at 34,860.
\end{enumerate}
\end{footnotesize}
upgrades identified in the 2009 S&L study for these units before 2012, eliminating opportunities for heat improvements relative to a 2012 baseline. As detailed in the S&L study specific to the CGS units, rather than an opportunity for an aggregate heat rate improvement of 2% as suggested by EPA, the achievable improvement in net heat rate through equipment upgrades at each of the two coal-fired EGUs at CGS is at most 1%.\textsuperscript{126} The analysis specific to the SGS units shows that 3 of the 4 units at SGS do not have any opportunities to further improve heat rate through equipment upgrades.\textsuperscript{127}

Second, EPA would have seen that, rather than opportunities for improvement in net heat rate at CGS relative to a 2012 baseline, any heat rate improvement opportunity would be negated with the recent addition of the Unit 2 SCR system or the proposed Unit 1 SCR system at CGS, as required by other air pollution control requirements imposed by EPA. In particular, in 2012, EPA issued a FIP that would require the installation of an SCR system at CGS Unit 1.\textsuperscript{128} Compliance with that FIP is expected to increase net heat rate at CGS Unit 1 by at least 1%, completely offsetting any potentially achievable improvement in heat rate through a costly turbine upgrade at this coal-fired EGU. Thus, relative to a 2012 baseline, there is no opportunity for heat rate improvement at this unit.

Even more troubling than EPA’s assumptions regarding achievable improvements in net heat rate at coal-fired EGUs constructed in or before the 1980’s, such as those at CGS, is the fact that EPA made the same assumptions for state-of-the-art coal-fired EGUs, such as the SRP-owned Unit 4 at SGS. SGS Unit 4 commenced operation in 2009 and, based on the Part 75 monitoring data that was the basis for EPA’s analysis of heat rate variability, has a gross heat rate of approximately 8,800 Btu/kWh. This is approximately 10% less than the average for EPA’s “study population,” reflecting the fact that the initial design of this and other state-of-the-art units already includes the technological upgrades upon which EPA based its assumptions regarding achievable improvements in net heat rate at coal-fired EGUs.

Although EPA makes clear that the 2009 S&L study is the sole basis for its assumption regarding the achievability of heat rate improvements through equipment upgrades, EPA also summarily discusses other sources of purportedly pertinent data that it considered. One of those is a subset of the “study population” of 884 EGUs.

\begin{footnotes}
\item[126] See Appendix H.
\item[127] Unit Heat Rate Improvement Study at Springerville Generating Station SL-012568 (Nov. 14, 2014). Sargent & Lundy. (Included as Appendix I of these comments.)
\item[128] 77 Fed. Reg. at 72,512.
\end{footnotes}
“The EPA inspected the study population to find examples of EGUs that made significant year-to-year improvements in heat rate. After filtering out those cases that may have been the result of changes in capacity factor, reporting method, or other events, we identified 16 EGUs that reported a single year-to-year heat rate improvement of 3-8%. In two of these cases we were able to identify equipment upgrades responsible for 2-3% heat rate improvement using the applicable estimates from the Sargent & Lundy 2009 study. Similarly, in the other cases, while our research was unable to confirm specific equipment upgrades, based on the elimination of other possible explanations we believe that equipment upgrades were the most likely cause of some of the observed heat rate improvements.”

As with the earlier discussion of hour-to-hour variability, the inferences drawn by EPA based on apparent year-to-year improvements in gross heat rate shown by the “study population” data set are not appropriate. There are at least two fatal flaws in EPA’s logic with respect to this data set. First, fluctuations in reported heat input rate are more likely the result of measurement error or factors other than actual improvements in EGU efficiency. Here, having admitted that it had no basis for presuming that the observed fluctuation in gross heat rate at 14 of the 16 referenced EGUs was attributable to an equipment upgrade, EPA did not even attempt to determine whether the purported improvements in heat rate were sustained.

Second, in 2012, at the conclusion of EPA’s study period, of the 16 referenced EGUs at which EPA touts the efficiency gains purportedly achieved through equipment upgrades, eight had a gross heat rate higher than the 9,753 Btu/kWh, which EPA claims is the average for the “study population” as a whole. In other words, EPA’s presumption, even if it were true, would show only that equipment upgrades can be used to achieve the 2012 baseline level. It would not be informative as to whether widespread equipment upgrades can be used to achieve heat rate improvements beyond that level, which is what EPA’s proposal would require.

More robust analyses of the potential improvements in heat rate of coal-fired EGUs have been performed by agencies within the federal government that have particular expertise in efficiency and reliability of fossil fuel-fired EGUs. EPA has overlooked this work in deriving its own conclusions regarding heat rate improvements under Building Block 1. For example, a Department of Energy (DOE) analysis published in 2014 included the following findings:

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“As these results show, the potential reduction in emissions (in percent terms) is greatest when the base plant (before retrofit) is less efficient. This is a recurring theme throughout the analysis, and is intuitive: when efficiency improvements are performed at an existing coal unit, there is greater potential for improvement at a unit that operates less efficiently to begin with, than at a newer unit with an already-low heat rate.

* * *

These results illustrate that a ‘one-size fits all’ solution does not exist when it comes to power plant retrofits, and that some retrofits may not make sense for certain plants, such as pulverizer upgrade for Plant B. Instead, utilities are likely to weigh their options based on the expected plant life, anticipated fuel costs, and other such factors – such as familiarity with a technology – before making the decision to invest in capital improvements.”

(d) EPA Failed to Address NSR Implications Associated with Building Block 1

EPA’s assumptions regarding the achievable improvement in heat rate across the fleet of twelve coal-fired EGUs in Arizona, both through adoption of best practices for operation and maintenance and through equipment upgrades, do not take account the requirements of the agency’s own New Source Review (NSR) programs under the CAA and 42 U.S.C. §§ 7475 and 7502(c)(5). EPA’s assumptions regarding achievability of increased capacity factor at NGCC units similarly fails to take these effects into account. EPA addresses the NSR programs only summarily in the preamble to the Proposed Rule:

“As a result of such flexibility and anticipated state involvement, we expect that a limited number of affected sources would trigger NSR when states implement their plans.”

EPA’s analysis of the economic impacts of the Proposed Rule does not address any costs for even the “limited number” of NSR-triggering projects that it acknowledges would occur.

More importantly, EPA also fails to recognize that the predominant costs of compliance with the NSR programs are incurred not in the context of obtaining NSR permits, but in efforts to avoid triggering preconstruction NSR permitting. EPA’s speculation regarding the number of stationary sources that would actually trigger preconstruction NSR permitting is therefore not

131 79 Fed. Reg. at 34,929.
informative as to the total costs that would be incurred by owners and operators of affected EGUs to comply with NSR program requirements, if it were possible to achieve the heat rate improvements and increased capacity factor required by the Proposed Rule.

Although in the current rulemaking EPA appears to ignore the “NSR permit avoidance” compliance option available to owners of affected EGUs and overlooking the costs of this compliance mechanism, it is not because EPA is unaware that this compliance mechanism is frequently used. For example, in both internal and external correspondence regarding the project proposed by the Wisconsin Electric Power Company (WEPCO), which ultimately led to the landmark WEPCO court decision, EPA officials specifically recognized the possibility that WEPCO would implement emissions-reducing measures in order to avoid preconstruction NSR permitting requirements.

“WEPCO may lawfully avoid both PSD [prevention of significant deterioration] and NSPS [new source performance standards] requirements by adding or enhancing pollution control equipment, or, in the case of PSD, restricting operations below maximum potential, such that the emission increases necessary to trigger applicability would not occur. Based on information supplied by WEPCO, it is our understanding that the company already intends some enhancement of pollution control equipment, and WEPCO may desire to undertake a combination of the measures outlined above rather than subject itself to the Act’s new source requirements. If this is indeed the case, WEPCO should so inform me so that appropriate discussions may be held between WEPCO, this office, and the State, regarding the steps that would be necessary to render the project not subject to PSD and NSPS.”

In addition, in responding to Congressional oversight regarding its implementation of the NSR programs for coal-fired EGUs, EPA touted the flexibility provided by the NSR program for implementation of emissions-reducing measures to avoid preconstruction NSR permitting requirements:

“EPA regulations contain broad “netting” provisions that enable source owners to offset emissions increases with equivalent reductions and thereby avoid the applicability of new source emissions standards or BACT [best available control technology] limits. Under NSPS, netting may occur within the affected facility

132 Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901 (7th Cir. 1990) (WEPCO).
(e.g., an individual utility boiler) and involve physical restrictions on emissions capabilities (such as addition of pollution control equipment). Under PSD and nonattainment area new source review, netting may occur within the entire plant and may involve operational as well as physical restrictions on the plant’s emissions.”

The owner or operator of an EGU may employ any method or technique it chooses, either voluntarily or through enforceable permit terms, to avoid emissions increases and thereby avoid preconstruction NSR permitting requirements. Compliance with the NSR program, even under this interpretation, is exorbitantly costly, but not as costly as it would be if source owners and operators were constrained with respect to the available techniques for avoiding emissions increases.

As shown by the following statement in the preamble to the Proposed Rule, EPA’s conclusion regarding a small number of EGUs at which preconstruction NSR permitting requirements will be triggered is based on the assumption that, even for a modification to an EGU which is initially projected to cause a threshold emissions increase, the owner or operator of the EGU may lawfully avoid NSR simply by hoping that electric demand will not increase.

“[A] state could decide to adjust its demand side measures or increase reliance on renewable energy as a way of reducing the future emissions of an affected source initially predicted (without such alterations) to increase its emissions as a result of a CAA section 111(d) plan requirement. In other words, a state plan’s incorporation of expanded use of cleaner generation or demand-side measures could yield the result that units that would otherwise be projected to trigger NSR through a physical change that might result in increased dispatch would not, in fact, increase their emissions, due to reduced demand for their operation.”

EPA has not demonstrated how such an approach is consistent with the existing major NSR provisions that require a major source to project post-change emissions before undertaking a project. With respect to demand growth, EPA has explicitly stated that even if a facility could have met the level of demand before a change, if “it can be shown that the increase is related


135 79 Fed. Reg. at 34,928.
Moreover, EPA’s assurances that few projects at existing EGUs implemented for the purpose of complying with the Proposed Rule will trigger preconstruction NSR permitting requirements ring hollow, as those assurances are reminiscent of EPA’s earlier statements regarding maintenance projects, and pollution control projects. For example, in 1991, EPA assured Senator John Dingell, that the WEPCO ruling would not affect power plant life extension projects. EPA then proceeded to initiate enforcement actions against all life extension projects.

With regards to pollution control projects, until 2005, EPA implemented a pollution control technology exclusion from major NSR for environmentally beneficial projects. In 2005, the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) overturned that exclusion as contrary to the CAA. EPA later filed a request asking the Court to specify that its mandate would not have retroactive effect (which the Court found not ripe for decision); yet, at the same time, EPA’s enforcement office filed enforcement actions against coal-fired utilities that relied on EPA’s pollution control project exclusion in good faith. With this history, EPA cannot expect any facility to trust that EPA would craft a legally supportable exclusion that would be upheld by the Court, and that EPA would not enforce against a facility relying on such an exclusion, when a Court later rules against that exclusion.

Indeed, EPA’s request for comments regarding the appropriateness of a categorical exemption from NSR for projects undertaken to comply with the Proposed Rule is disingenuous. It is telling that this, a legal issue plainly turning on the clarity of statutory language and on congressional intent, is nowhere raised in the “Legal Memorandum” prepared by EPA, the express purpose of which is to “provide background for the legal issues discussed in the preamble for [the] proposed rule.” As EPA is well aware, policy-driven exemptions such as this are contrary to the broad statutory language governing applicability of the NSR program to modifications at existing EGUs, and efforts to provide these exemptions have been consistently rejected by the courts.

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138 EPA Legal Memorandum at 1.
7.2 Building Block 2 – NGCC Redispatch

With this building block, EPA redisciplines existing coal and OG steam generation to existing NGCC generation. In the preamble of the Proposed Rule, EPA states that increasing the utilization rates of existing NGCC units to 70% on average – as part of a comprehensive approach to reducing CO₂ emissions from existing high-carbon intensity units (e.g., coal-fired and OG-fired units) – is technically feasible.

For Arizona, EPA calculated a 2012 capacity factor for NGCC generation of 27%. Based on EPA’s presumption that NGCC utilization rates can be boosted to 70%, the agency adjusted Arizona’s emission rate to account for higher usage of existing NGCC to meet annual generation needs. Using this approach, EPA calculated that the capacity factor for the NGCC fleet would need to be 53% for the state of Arizona to provide the same total generation as in 2012. At this level NGCC generation entirely displaces coal and OG steam generation as illustrated in Figure 7-1.

**Figure 7-1: EPA Redispatch Assumptions for Arizona**

<table>
<thead>
<tr>
<th>State</th>
<th>Hist Coal Gen. (MWh)</th>
<th>Hist NGCC Gen. (MWh)</th>
<th>Historic OG steam Gen. (MWh)</th>
<th>NGCC Capacity (MW)</th>
<th>Redispatched Coal Gen. (MWh)</th>
<th>Redispatched NGCC Gen. (MWh)</th>
<th>Post Redispatch Assumed NGCC Capacity Factor*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alabama</td>
<td>46,045,176</td>
<td>53,492,096</td>
<td>0</td>
<td>10,333</td>
<td>36,001,107</td>
<td>0</td>
<td>70%</td>
</tr>
<tr>
<td>Alaska</td>
<td>2,15,407</td>
<td>2,204,942</td>
<td>0</td>
<td>11202</td>
<td>0</td>
<td>0</td>
<td>47%</td>
</tr>
<tr>
<td>Arizona</td>
<td>24,335,930</td>
<td>26,782,325</td>
<td>1,033,871</td>
<td>11,202</td>
<td>0</td>
<td>0</td>
<td>53%</td>
</tr>
</tbody>
</table>

Of the four building blocks included in EPA’s BSER determination, Building Block 2 produces the most dramatic impact on the calculation of the interim and final goals for Arizona. This building block alone accounts for more than 80% of the total reductions associated with the proposed goals for Arizona.

EPA’s assumptions regarding application of Building Block 2 within Arizona do not recognize the need to meet peak demand, and do not recognize the constraints inherent in making such a

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140 Clearly, EPA has contradicted itself on whether heat rate improvement projects would be expected to increase emissions and, thus, trigger NSR. It is untenable for EPA to conclude in the Proposed Rule that heat rate improvement projects do not increase emissions and later enforce against EGUs by claiming that the EGU should have projected that such heat rate projects would increase emissions and trigger NSR. EPA should issue new NSR guidance to adopt its stance in the Proposed Rule that heat rate improvement projects are not the type of projects that should trigger NSR requirements. Although this would not necessarily reduce the threat of citizen suits for such projects, it would bolster companies’ defenses of such claims and could encourage states to issue conforming applicability determinations.

wholesale shift in the state’s current energy infrastructure. Particularly troubling is EPA’s assumption (at least with regard to Arizona goals) that reductions related to Building Block 2 are easy to achieve – a company would, in effect, flip a switch in 2020 that turns off its coal units and turns on its gas units. The dramatic impact of this assumption on Arizona is shown in Figure 7-2, which is a graphical depiction of the EPA’s goal calculation for Arizona.

Figure 7-2. Impact of EPA’s Proposed Goals in Arizona

Therefore, for reasons described in detail below, it is imperative EPA make changes in the application of Building Block 2 that reflect a more rational path to changes in CO₂ emissions intensity within the state.

(a) EPA Fails to Demonstrate Technical Feasibility of Building Block 2
EPA has not established the technical feasibility of switching to NGCC to meet Arizona’s interim emissions intensity goal. EPA appears to rely on anecdotal evidence to presume that it is feasible to complete the infrastructure improvements to the state’s natural gas pipeline capacity necessary to use existing NGCC units to support baseload generation needs.

First, EPA does not address the time needed to complete critical project tasks before actual construction can begin, such as an extensive public involvement process, regulatory proceedings before local committees and commissions, obtaining rights-of-way, acquiring permit authorizations, conducting environmental assessments, and procuring bank financing.
These activities are a necessary part of any major energy infrastructure project and must be accommodated in EPA’s projected timelines for achievement of emissions reductions under at 111(d) program.

Second, EPA’s goal calculation assesses the ability of NGCC generation to replace coal and OG steam generation using 2012 coal generation levels as a basis for supply shifts. Yet, 2012 was the lowest coal generation utilization rate in Arizona in the past 10 years and is not representative of an electric utility system under full demand load.

Third, EPA bases its NGCC capacity analysis on an assumption that NGCC units operate at higher levels for a set period of the day and that this level of operation can be extended and sustained without risk to natural gas pipeline capacity. However, as discussed previously in Section 3, this assumption is not valid when capacity is unavailable for baseload generation use because of competing purchasers and inadequate existing infrastructure. Even if a demand level can be met during a certain hour of the day, this does not provide sufficient evidence that the natural gas transmission system can sustain this level of capacity for a prolonged period of the day. Additional study specific to the natural gas transmission system in Arizona would be needed to determine what would be required to support using existing NGCC generation for baseload generation.

Finally, EPA provides Energy Information Administration (EIA) data on current pipeline capacities in the U.S., but provides no information on the amount of residual capacity available in the current system or the capacity projected as needed to meet EPA’s assumptions regarding utilization of the current NGCC fleet at a 70% capacity factor. Indeed, actual available capacity may be far below 100% of nameplate capacity due to bottlenecks in the system. Comments submitted by NERC confirm this concern:

“…there are a few critical areas that likely will need additional capital investment. As an example, current and planned pipeline infrastructures in Arizona and Nevada are inadequate for handling increased natural gas demand due to the Clean Power Plan.”

SRP strongly encourages EPA, before it proceeds with a final rule, to consult with federal and state agencies with greater expertise in operation of the country’s natural gas transmission system (e.g., FERC and the United States Department of Transportation Office of Pipeline Safety) to gain a greater understanding of the infrastructure expansion needs associated with application of Building Block 2, such as trunklines, compressor stations, and peaking storage

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142 NERC, Reliability Impacts Potentially Resulting from the CPP, November 2014, at10.
facilities, and the timelines necessary to complete such projects. This understanding is fundamental to establishing the technical feasibility of Building Block 2. As discussed further in the following section, SRP is particularly concerned that the high proportion of federal, state, and tribal lands in the Western U.S. represent unique challenges to timely completion of new energy-related projects.

(b) EPA Assumptions Related to NGCC Capacity
EPA’s application of Building Block 2 to establish Arizona’s emissions rate goals suggests the agency does not recognize a utility’s obligation to meet peak demand. Utilities must ensure that sufficient resources are available to meet peak demand, not just annual average demand. Peak demand occurs when consumer demand for electricity is at its highest level, which for Arizona typically corresponds with the high temperatures in the summer months. During these months, temperatures regularly exceed 110 °F. EPA’s calculation does not account for the much higher demand for electricity in Arizona in the summer than in the winter. Arizona-based NGCC generation – both utility-owned and merchant – is called on heavily in the summer months and much less in the winter months when demand is very low. An NGCC resource could easily run at a 90% capacity factor during the peak summer hours, but have an annual capacity factor around 30%.

For example, Figure 7-3 on the following page illustrates peak demand for electricity (“retail firm load”) from SRP’s system in 2012. Peak electricity demand can be more than twice as high as base demand in the off-peak months. Furthermore, while forecasted values trend well with actual values, utilities still cannot predict exactly when the highest peak will occur and how high that peak will be.

On August 8, 2012, SRP reached its highest peak hourly load value of 6,663 MW. Figure 7-4 on the following page shows a breakdown of the generating resources that were operating during that peak hour to meet customer demand. During this hour, all available generation resources, including coal and OG steam plants, were being utilized at full capacity to meet that peak demand. Even with all SRP system resources being utilized at full capacity, SRP still had to purchase electricity on the open market to meet peak demand and Federally-required reserve requirements.

It is clear that without coal and OG steam resources, SRP would not have been able to meet the peak electricity demand without purchasing a significant amount of electricity from the short-term market in addition to what is already being purchased, which is a costly and risky endeavor, assuming that such power is even available. Neighboring states in the southwestern U.S. also experience these high peaks in the summer. As such, other utilities are likely to be
competing for that same power, at the same time, on the short-term market.

Figure 7-3. 2012 SRP Retail Firm Load Profile

![Graph showing the 2012 SRP Retail Firm Load Profile. The graph displays the power (MW) over time from January 2012 to December 2012, with two lines indicating forecast and actual power demands.]

Figure 7-4. Resources Needed by SRP to Meet Peak Demand on August 8, 2012

![Bar chart showing the resources needed by SRP to meet peak demand on August 8, 2012. The chart includes various power sources: Purchases, Hydro/Renewables, Other Gas, NGCC, Nuclear, and Coal. The peak demand is 6,663 MW.]

* All available generation resources were operating at full capacity, except for a small portion held to meet reserve requirements.
While Figure 7-4 shows a single peak hour, Figure 7-5 provides an annual look at how SRP’s generation resources would fall short if SRP were required to replace all existing coal and OG steam generation with NGCC generation. For illustrative purposes, SRP assumed a 100% NGCC capacity factor on an hourly basis, which equates to 84% on an annual average basis. This level of dispatch exceeds EPA’s assumption of 70% on an annual average basis.

**Figure 7-5. Potential Rediash of SRP Generation Resources**

As Figure 7-5 demonstrates, even with an extremely aggressive NGCC rediash assumption, SRP still would experience significant shortages in generation for several months in the summer. This lack of generation would be further aggravated if out-of-state coal resources also are eliminated due to compliance with the Proposed Rule.

It is also important for EPA to be aware that there are a number of merchant NGCC plants in Arizona that EPA included in the total capacity available for rediash. Merchant plants differ from traditional rate-based power plants in how they are financed and where they sell the electricity they generate. A merchant plant is funded by investors and sells electricity in the competitive wholesale power market where it can receive the highest price.

The nominal capacity available from merchant generators in Arizona is more than 5,000 MW, accounting for 53% of the NGCC capacity in the state. Arizona’s load serving entities, including SRP, purchase energy from merchant generators through long-term firm purchase agreements.
or through shorter term transactions. Aside from making such purchases, Arizona’s utilities have no control over the dispatch of merchant generation.

Setting aside constraints on merchant use posed by their business structure, SRP investigated the availability of merchant NGCC plants within Arizona using data obtained from EPA’s Clean Air Markets Database, which was used to determine hourly generation loads. Figure 7-6 shows the level at which merchant NGCC plants were dispatched over the peak hour on each day in the summer of 2012.

As demonstrated by Figure 7-6, the merchant plants in Arizona often already operate at full or nearly full output during summer peak months to meet demand, even with the existing coal-fired generation in operation. Consequently, Arizona utilities cannot rely on merchant generation in long-term planning to meet system demand requirements during peak summer demand periods. It should further be recognized that regional peak demands have been increasing and are projected to continue to increase.

**Figure 7-6. Merchant NGCC Plant Utilization in Arizona**

Arizona cannot solely rely on existing NGCC capacity to meet peak demand because those facilities are already being fully utilized in certain hours of the year to serve regional loads. Currently, coal and OG steam plants provide vital capacity during summer months that ensures system reliability during periods of peak demand.
If Arizona’s emissions rate goals can be met only through retirement of all coal and OG steam plants, not only will new infrastructure be needed to support baseload use of existing NGCC plants, but additional new NGCC resources will be needed to cover state electricity demand.

EPA did not presume that new resources would be needed to replace coal and OG steam in setting state emission rate goals. For states with goals that will require significant new energy infrastructure, EPA must provide adequate time to site, plan, design, permit, and construct these facilities (e.g., new NGCC plants, high voltage electric transmission, and natural gas pipelines).

There are several factors that complicate a utility’s ability to construct the new energy infrastructure needed to meet the requirements associated with the Proposed Rule. One of the biggest issues is the lengthy timelines associated with obtaining necessary environmental approvals to construct and operate these facilities.

The Western U.S. is unique in the amount of land owned by the federal government, state governments, and tribal nations. SRP is particularly concerned that the high proportion of federal, state, and tribal lands in Arizona – more than 80% – represents unique challenges to timely completion of new energy-related projects. Specifically, in Arizona, approximately 41% of land is owned by the federal government, almost 13% is controlled by the state, and about 27% belongs to tribal nations.\footnote{Natural Resource Council of Maine, Public Land Ownership by State. Available at http://www.nrcm.org/documents/publiclandownership.pdf; see also Breakdown of Federal and Tribal Lands in Region 9, http://www.epa.gov/region9/fedfac/fedmap.html (detailing federal and tribal lands).} In addition, 7,220 square miles within the state have been identified as critical habitat for threatened or endangered species listed under the Endangered Species Act. Figure 7-7 on the following page shows the extensive amounts of federal and tribal lands within Arizona, including critical habitat designations.

Siting and permitting of new energy infrastructure on federal land can take 10 years or more. In many cases, obtaining the permits necessary to construct a transmission line can take longer than constructing the line itself.

As discussed in Section 3 of these comments, the SunZia Southwest Transmission Project, which is intended to provide an option to develop additional power generation resources in Arizona and New Mexico, started the process to obtain required federal environmental approvals in 2008 and has yet to secure these approvals and proceed with project construction.\footnote{SunZia Southwest Transmission Project at www.sunzia.net.} The expected completion date for the project has been delayed to 2018 – more than 10 years after permitting for this project began.
Figure 7-7. Arizona Federal and Tribal Lands, Including Critical Habitat Designations
Another issue that will affect the timeline for siting and construction of new NGCC facilities is the attainment status of the location(s) where the resource is needed. Maricopa County, which is home to the largest proportion of the state’s population, currently does not meet EPA’s NAAQS for ozone or coarse particulate matter. The ozone standards are expected to be lowered by EPA in the near future. The CASAC Ozone Review Panel has determined that “there is adequate scientific evidence to recommend a range of levels for a revised primary ozone standard from 70 ppb to 60 ppb.”\textsuperscript{145} WESTAR has conducted modeling that indicates that if the EPA chooses any value within the proposed range, many new areas of the state could transition to nonattainment status. An example of this work is shown in Figure 7-8, which identifies anticipated nonattainment areas if the revised primary standard is set at 65 ppb.

\bf{Figure 7-8. WESTAR Modeled Ozone Nonattainment Area at 65 ppb}\textsuperscript{146}

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{westar_modeled_ozone_nonattainment_area.png}
\caption{WESTAR Modeled Ozone Nonattainment Area at 65 ppb}
\end{figure}

\textsuperscript{145} Letter from Dr. H. Christopher Frey, CASAC, to Gina McCarthy, EPA. \textit{CASAC Review of the EPA’s Second Draft Policy Assessment for the Review of the Ozone National Ambient Air Quality Standards}, EPA-CASAC-14-004 (June 26, 2014).

As EPA is aware, to construct a source in a nonattainment area, a project developer must obtain emissions offsets,\(^{147}\) which may not be readily available.\(^{148}\) Projects are often delayed to allow for development of needed offsets through other air quality control projects.

(c) EPA Assumptions Related to NGCC Emission Factors

In calculating the emission rate targets for Arizona, EPA assumed that NGCC units would operate in future years at a CO\(_2\) emission rate of 900 lb CO\(_2\)/MWh. This value is the combined average annual emissions rate of all NGCC units in Arizona during 2012.

However, the emissions rate applied by EPA to existing units is at odds with EPA’s proposal to establish standards of performance for CO\(_2\) emissions for new NGCC units. Specifically, in EPA’s January 2014 proposal, CO\(_2\) emission rates for new units were proposed at 1,000 lb CO\(_2\)/MWh for NGCC units with a capacity greater than 850 million British thermal units per hour (MMBtu/hr) and 1,100 lb CO\(_2\)/MWh for NGCC units with a capacity of 850 MMBtu/hr or less.\(^{149}\) EPA asserts that these emission rates can be met over the lifetime of a modern, high efficiency NGCC unit and are representative of the emissions rates of the best performing NGCC units in the country.

Even at these higher limits, EPA still acknowledges in the preamble of the Proposed Rule that nearly 10% of units today could not achieve the standards they have proposed for new units.

“...because over 90 percent of small and large existing NGCC facilities are currently operating below the emissions rates of 1,100 lb CO\(_2\)/MWh and 1,000 lb CO\(_2\)/MWh, respectively, these rates are considered BSER for new NGCC facilities in those respective subcategories.”\(^{150}\)

In calculating state goals under 111(d), EPA has assigned a more stringent CO\(_2\) emission rate to existing NGCC units than the agency is proposing to assign to new, higher efficiency NGCC units. The analysis EPA conducted under its 111(b) proposal should hold true under the current 111(d) proposal since EPA evaluated all existing NGCC generation before setting the emissions rate limit for new units. A copy of SRP’s comments on the proposal for new units is included in Appendix J of these comments.

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\(^{147}\) 42 U.S.C. § 7503.

\(^{148}\) For example, in Maricopa County, there were only 14.1 nitrogen oxide credits in the ADEQ Emissions Bank Registry as of November 2014. See http://www.azdeq.gov/databases/banksearch.html.

\(^{149}\) 79 Fed Reg. at 1,433.

\(^{150}\) Id. at 1,487.
EPA Assumptions Related to Remaining Useful Life

EPA does not adequately address “remaining useful life” in its BSER analysis. In the preamble of the Proposed Rule, EPA discusses how states can address remaining useful life:

“Importantly, the proposed BSER, expressed as a numeric goal for each state, provides states with the flexibility to determine how to achieve the reductions (i.e., greater reductions from one building block and less from another) and to adjust the timing in which reductions are achieved, in order to address key issues such as cost to consumers, electricity system reliability and the remaining useful life of existing generation assets.” ¹⁵¹

EPA’s proposed approach of not allowing states to consider remaining useful life in setting standards of performance, because the agency’s BSER already allows for consideration of remaining useful life, contradicts the plain language of the CAA and is unsupportable both on a legal and policy basis.

In 1970, the CAA defined “standard of performance” as “a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated.” ¹⁵² EPA proposed regulations to implement these provisions of the CAA in 1974. ¹⁵³

In response to that proposal, EPA received adverse comments expressing concern over the level of emissions reduction EPA might require for existing sources, and challenging EPA’s legal authority to establish specific “emissions limitations” that states must follow. When EPA finalized its rule in 1975, it responded to these comments by changing terminology from “emission limitation” to “emission guideline” to assure commenters that the guidelines would not have “the purpose or effect of national emission standards.” Moreover, EPA reassured commenters that:

“States will be free to set more lenient standards,… as provided in (f) …based on economic hardships.” ¹⁵⁴

“It is up to the State to decide whether less stringent standards are to be applied...” ¹⁵⁵

¹⁵¹ 79 Fed. Reg. at 34,836.
The only standard EPA put forth for judging state actions under paragraph (f) was “sufficient justification” and “some economic justification” and “some reasoned explanation.”

Two things are apparent from the final rule preamble from 1975. First, EPA intended paragraph (f) to implement the 1970 CAA provision related to “taking into account the cost of achieving such reduction,” and in doing so, it vested states with broad authority to custom-tailor the emissions guidelines to sources in its state so long as the state presented some reasoned justification. Second, EPA’s assertion of legal authority to establish emission limitations that states must follow in emissions guidelines is tempered by, and inherently linked to, the authority provided to states to justify a less stringent standard for specific sources based on cost and other considerations.

Yet, today EPA would now point to paragraph (f) as providing the implementing regulations for much broader statutory language that Congress added to Section 111 of the CAA after EPA codified paragraph (f) into its regulations. In 1977, and then again in 1990, Congress amended the definition of “standard of performance” so that it now requires consideration of numerous factors other than costs and explicitly states that EPA shall allow a state to consider “remaining useful life of the existing source.” EPA’s attempt to declare that the “system” already allows the state to consider useful life and other factors appears disingenuous when EPA made no attempt to include such factors in establishing the “system.” Nothing in EPA’s proposed interpretation of existing paragraph (f) satisfies the separate and different authority Congress conferred on states to consider “remaining useful life.” Remaining useful life is more than a “cost” consideration; nothing in the CAA suggests that Congress meant to bind states’ discretion to consider remaining useful life only as it relates to cost. Accordingly, EPA’s attempt to retrospectively interpret paragraph (f)(1) to satisfy Congress’ direction to consider both “remaining useful life” and “cost” is not supported by any reasonable interpretation of the CAA.

EPA appears to interpret paragraph (f) as satisfying Congress’ direction for allowing states to consider remaining useful life, while also proposing that it may, at its discretion, decide not to give effect to paragraph (f) when EPA sets emissions guidelines that are purportedly “flexible.” EPA’s rationale that “flexibility” substitutes for consideration of the factors in paragraph (f), and for the statutory mandate to allow states discretion to consider remaining useful life, fails for lack any analyses showing that Arizona can in fact meet the CO₂ emission limits proposed by EPA without shutting down numerous coal-fired EGUs with significant remaining useful life.

155 Id at 53,344.
Merely suggesting that the state can look elsewhere for reductions falls short of a reasoned justification for equating flexibility with the ability to properly consider remaining useful life.

EPA asserts that Congress understood that emissions standards might result in production decreases or plant closures when no control technology exists to reduce pollution. EPA quotes Congressional record related to the section 112 air toxics program to support this notion. But, EPA’s citation does little to prove its point.

While Congress may have understood that plant closures may be necessary to prevent human exposure to acutely toxic emissions, this does not mean that Congress would expect the same outcome under a section 111(d) standard for pollutants that, by definition, not toxic. In fact, evidence exists for an opposite conclusion. Congress was greatly concerned about the impact that emissions control requirements could have on industries’ decisions to continue to operate and sought to adopt approaches that balanced the need for environmental protection with the desire to promote continued economic growth and protect workers from job losses due to environmental compliance.

And even if EPA could locate other support for its improper inference that Congress supported closing plants, the Congressional Record could not be clearer on its desire to support policies that assure equal treatment of domestic fuel sources. In the 1977 Amendments, Congress specifically found that EPA’s implementation of section 111 standards of performance failed to achieve the purposes of section 111 on several fronts. Among other things, the standards:

- Improperly provided a competitive advantage to those states with cheap low-sulfur coal and disadvantages to states with high sulfur coal;
- Failed to consider maximum emissions reductions that could be achieved with locally available fuels;
- Increased the risk of plant shutdowns and increased unemployment rather than creating employment benefits; and
- Exacerbated problems facing coal-burning stationary sources that cannot retrofit and compete with new sources.

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158 Senator Muskie’s statements related to regulation of hazardous air pollutants under Section 112 – pollutants for which exposure can cause cognizable, acute, toxic effects.


EPA cannot propose an emissions guideline that fails in precisely the same way, by failing to allow states to determine how best to consider remaining useful life in setting and implementing a standard of performance in its state.

In 2010, ICF International (ICF) published an analysis estimating the coal-fired electric generating capacity at risk of retirement due to impending regulations and declining useful life. In its assessment, ICF identified no Arizona coal-fired electric generating capacity that would be at risk of retirement based on its defined assumptions. In other words, in 2010, Arizona’s coal-fired plants had a sufficient remaining useful life such that it could be assumed that all of the plants would continue to operate for some time in the future. This is especially true of SRP’s assets.

SRP owns SGS Unit 4, which came on line in December 2009 at a cost of $1 billion. The bond financing for construction of this coal-fired EGU was approximately 30 years with final bond maturity occurring in 2038. EPA acknowledges that the useful life of a coal-fired unit operating to meet base load demand is 40 years. Accordingly, EPA should expect that SGS Unit 4 would remain operating as a base load facility until at least 2049.

SRP also recently completed air pollution control equipment upgrades on CGS Units 1 and 2 at a cost of approximately $470 million. The bond financings for this project were likewise approximately 30 years with the final bond maturity occurring in 2041. In addition, EPA established emission control requirements based on an assumed remaining useful life of 20 years, which presumes that CGS would continue to operate beyond 2030.

In EPA’s 2012 BART FIP for CGS, EPA used a “remaining useful life” of 20 years to calculate the cost-effectiveness of adding another selective catalytic reduction system at CGS. EPA based this value on a default 20-year amortization period recommended in the EPA Control Cost Manual because EPA was unaware of any federal or state requirement that would require the sources to shut down by a specified date.

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164 77 Fed. Reg. at 42,834. At the same time EPA advocates for additional, costly capital investments in Units 1 and 2 to comply with BART based on a 20-year remaining useful life, it argues in a different forum that Arizona need not consider the actual “remaining useful life” because the “flexible” BSER that would require shut down of these Units by 2020 already provides for this consideration.
EPA’s proposal puts SRP in the difficult position of responding to a mandate under the BART FIP to install approximately $110 million of additional pollution equipment on CGS Unit 1 by December 2017 and then turn around and strand that investment just 2 years later through shutdown of CGS in 2020 to meet the state’s stringent emissions rate interim goal of 735 lb CO$_2$/MWh. In an attempt to address this difficult position, SRP submitted a supplemental petition for partial reconsideration and stay of EPA’s final BART FIP rule on November 11, 2014. Within that petition, which is included as Appendix K of these comments, SRP specifically requests that EPA stay the effectiveness of the nitrogen oxides requirements within the BART FIP that are applicable to CGS pending EPA’s final rulemaking action on the Proposed Rule and completion of a state plan for Arizona.\(^{165}\)

SRP does not own SGS Unit 3, which came on line in 2006 at a cost of $939 million. But, SRP has a 30-year agreement to purchase power from Unit 3 with anticipation that this unit, nearly identical to Unit 4, also would have a useful life of at least 40 years.

SRP’s investments in the CGS and SGS units are substantial and are being recovered in the rates of the SRP customers. As of October 31, 2014, the book value for these units exceeds $1.5 billion – $630 million for CGS Units 1 and 2 and $900 million for SGS Unit 4. Prematurely retiring Arizona coal generation will place an unreasonable burden on electricity customers who must now cover stranded costs, as well as the cost of building the new infrastructure required to replace this generation.

EPA should not by policy, and cannot by virtue of the CAA, usurp the states’ authority to consider the “remaining useful life” of section 111(d) regulated facilities. To do so defies cooperative federalism, which serves as the foundation of the CAA. SRP urges EPA to abandon its proposed approach of disallowing use of paragraph (f) in approving state plans, and recognize states’ authority under the “remaining useful life” CAA mandate, as described in Section 3 of these comments.

### 7.3 Building Block 3 – Expanded Use of Low- or Zero-Carbon Generation

With this building block, EPA reduces emissions from affected fossil-fired units in the amount that results from substituting generation at those units with expanded low- or zero-carbon generation. EPA identifies two types of generating capacity that can play this role – new renewable generating capacity and new/preserved nuclear capacity.

For renewable generation integration, EPA assumes a best practices scenario for increasing annual levels of renewable energy generation. Estimated increases are based on application of

\(^{165}\) See Appendix K, Supplemental Petition at 3.
an annual renewable energy growth factor to the state’s historical renewable energy generation, subject to a maximum renewable energy generation target. EPA develops growth factors and maximum generation targets separately for each of six established regions. Arizona is included in the West Region, which also includes California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming.

Certain nuclear generation comprises the second element. For this element, EPA provides two methods to address nuclear generation: 1) provisions to include identified new nuclear units in the state goals for the states where these new units are located,\(^\text{166}\) and 2) provisions to preserve existing nuclear units that might otherwise be retired.\(^\text{167}\) The EIA in its most recent Annual Energy Outlook projected an additional 5.7 GW of capacity reductions to the nuclear fleet in the future. As such, EPA determines that this portion of the U.S. nuclear fleet is “at risk” of being retired due to economic considerations.

To address these projections and provide some incentive for retaining this capacity in the U.S. generation mix, EPA includes in the state goal calculation the emission intensity reductions that would be supported by retaining 5.8% of each state’s historical nuclear capacity into the state goals for the respective states. For the purposes of goal computation, generation from under-construction and preserved nuclear capacity is based on an estimated 90% average utilization rate for nuclear units, consistent with what EPA states are the long-term average annual utilization rates across the nuclear fleet.

**(a) EPA Penalizes States That Already Have a Large Percentage of Carbon-Free Generation**

EPA’s proposal penalizes states that have acted to reduce GHG emission intensity through investment in carbon-free generation, including renewable energy and nuclear generation. Besides ignoring the actual proportion of carbon-free resources present within state boundaries through its failure to include existing nuclear and hydroelectric generation, EPA requires early acting states to meet more stringent interim and final performance standards.

EPA must recognize the significant efforts that states have made to reduce GHG emissions in the absence of a proposal such as that being contemplated by EPA.

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\(^{166}\) Five nuclear units at three plants are currently under construction: Watts Bar 2 in Tennessee, Vogtle 3-4 in Georgia, and Summer 2-3 in South Carolina.

\(^{167}\) EPA is aware of six nuclear units at five plants that have retired or whose retirements have been announced since 2012: San Onofre Units 2-3 in California, Crystal River 3 in Florida, Kewaunee in Wisconsin, Vermont Yankee in Vermont, and Oyster Creek in New Jersey.
“More than half the states already have established some form of state-level renewable energy requirements, with targets calling on average for almost 20 percent of 2020 generation to be supplied from renewable resources.”\textsuperscript{168}

Meeting these goals comes at a cost. Renewable energy generation can be more expensive than traditional fossil fuel-fired generation. These added expenses result in the imposition of greater costs to the customer, which they have already been saddled with for several years.

Now, EPA will impose even greater costs on utility customers who are already paying for early reductions. Under the Proposed Rule, EPA seeks to increase the renewable goals of states that have already achieved real GHG reductions while asking less of states where such opportunities still exist. This is neither equitable nor cost-effective.

Some argue that providing credit will enable states to get by without doing anything, but the real story is that these states have been generating real reductions for years without a rule in place. As discussed in Section 2 of these comments, SRP has already made significant strides in renewable implementation – these actions deserve to be credited.

(b) EPA Needs to Credit Out-of-State Renewable Resources

As mentioned in Section 2 of these comments, SRP has incorporated a diverse set of renewable energy resources into its resource portfolio. Table 7-1 on the following page shows the renewable resource capacity mix that made up the renewable energy portion of SRP’s Sustainable Portfolio in FY2013. A significant portion of the renewable generation in this portfolio is from out-of-state resources. It is imperative that EPA clearly state in the guidelines to states in the final rule that affected sources have the ability to include out-of-state renewable resources in compliance plans.

In the preamble of the Proposed Rule, EPA asserts that the Agency intends to provide states with flexibility to take advantage of renewable energy generation located out-of-state.

\textit{“The EPA is proposing that, for renewable energy measures, consistent with existing state RPS policies, a state could take into account all of the CO}_2\textit{ emission reductions from renewable energy measures implemented by the state, whether they occur in the state or in other states.”}\textsuperscript{169}

\textsuperscript{168} 79 Fed. Reg. at 34,858.  
\textsuperscript{169} 79 Fed. Reg. at 34,922.
Table 7-1. SRP Renewable Energy Mix Fiscal Year 2013

<table>
<thead>
<tr>
<th>Resource</th>
<th>In-State Generation (MWh)</th>
<th>Out-of-State Generation (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydropower</td>
<td>245,842</td>
<td>522,413</td>
</tr>
<tr>
<td>Wind</td>
<td>214,975</td>
<td>60,634</td>
</tr>
<tr>
<td>Geothermal</td>
<td>0</td>
<td>183,280</td>
</tr>
<tr>
<td>Solar</td>
<td>174,211</td>
<td>0</td>
</tr>
<tr>
<td>Biomass</td>
<td>91,780</td>
<td>0</td>
</tr>
<tr>
<td>Green Gas</td>
<td>99,851</td>
<td>0</td>
</tr>
<tr>
<td>Landfill Gas</td>
<td>27,166</td>
<td>0</td>
</tr>
<tr>
<td>Renewable Energy Credits&lt;sup&gt;170&lt;/sup&gt;</td>
<td>23,798</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>877,623</strong></td>
<td><strong>766,327</strong></td>
</tr>
</tbody>
</table>

SRP applauds EPA’s proposal in this respect. The ability to invest in renewable resources, both in-state and out-of-state, allows utilities to engage in more cost-effective development of these resources and promotes greater diversity of resource portfolios.

For example, SRP acquires the company’s geothermal resources from California and Utah, as this class of renewable resource is not readily available in Arizona. Similarly, Arizona has low potential for future wind power and biomass development. If SRP is not able to include out-of-state investments in these classes of renewable resources into the company’s plan to reduce CO₂ emissions intensity, the company will be constrained in its flexibility to use Building Block 3 for compliance.

SRP also supports EPA’s proposed approach as it pertains to the use of REC across state boundaries, as illustrated in Figure 7-9. According to EPA:

“This proposed approach for RE acknowledges the existence of renewable energy certificates (REC) that allow for interstate trading of RE attributes and the fact that a given state’s RPS requirements often allow for the use of qualifying RE located in another state to be used to comply with that state’s RPS.”<sup>171</sup>

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<sup>170</sup> Some renewable energy credits may be from out-of-state resources.

<sup>171</sup> 79 Fed. Reg. at 34,922.
SRP understands that some parties commenting on this proposal have expressed a concern that RE attributes could be double-counted by being claimed in multiple state plans. SRP is confident that states can avoid this issue through adoption of systems that create and track the use of RECs, such as WREGIS.

Using REC systems, such as WREGIS, would greatly expand RE procurement options for all participants. States would gain access to RE that could be used for compliance regardless of its deliverability. Participants with larger compliance obligations could purchase RECs from out-of-state RE projects that are more competitively priced than those that might be built in state.

Likewise, states with an abundance of RE projects beyond their compliance obligations could benefit by selling RECs to others. To the extent possible, SRP encourages EPA to provide states support in using RE accounting systems to fully realize available RE procurement options.\(^{172}\)

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\(^{172}\) Implementation of tracking and crediting systems have been successful in other EPA CAA programs. Specifically, under EPA’s Acid Rain Program, EPA implemented a sulfur dioxide trading program. EPA recognizes that programs such as these can provide meaningful, cost-effective emissions reductions. (“Through the market-based allowance trading system, utilities regulated under the Acid Rain Program decide the most cost-effective way to use available resources to comply with the requirements of the Clean Air Act.” See http://www.epa.gov/airmarkets/progsregs/arp/s02.html.)
(c) EPA Should Credit Existing Hydroelectric Generation Resources

Hydroelectric generation has played an important role in Arizona’s energy mix for the past 105 years, even before Arizona became a state. It can respond quickly to rapidly varying loads or system disturbances, which makes it a very valuable resource.

In the Proposed Rule, EPA stated that the Agency did not include hydroelectric generation due to its potential to distort regional targets for states lacking existing hydroelectric capacity. While SRP can appreciate the difficulty EPA faces regarding the inclusion of hydroelectric generation, existing carbon-free resources should not be ignored in the 111(d) program. SRP believes EPA should provide meaningful recognition of hydroelectric generation to encourage those states to continue to use this low-cost renewable resource.

(d) States Should Not Be Penalized for Existing Nuclear Generation That is Not At Risk

SRP is one of the owners of PVNGS, the largest nuclear power plant in the United States. Nuclear power represents an important part of SRP’s resource portfolio because it adds fuel diversity and provides reliable, baseload generation at a relatively low cost and with no CO₂ emissions.

In the Proposed Rule, EPA claims that a certain age of the U.S. nuclear fleet is at risk of retiring for various reasons and that “preserving the operation of at-risk nuclear capacity would likely be capable of achieving CO₂ reductions from affected EGUs at a reasonable cost.” EPA therefore proposes to include an “at-risk” nuclear component in the CO₂ goals for all states with nuclear generation. This “at-risk” nuclear component is calculated as 5.8% of the nuclear capacity in each state, assuming a 90% capacity factor. EPA includes this at-risk nuclear generation in the denominator of the CO₂ goals for each state that has nuclear power plants as an incentive for those states to keep those plants online and operating.

Under EPA’s proposal, the nuclear generation within the state would have to meet or exceed the 90% capacity factor assumed in the calculation for the state to achieve its CO₂ goals. If the nuclear generation does not meet the 90% capacity factor threshold in a given compliance year, the state would have to implement more renewable generation or energy efficiency measures to offset the shortfall in nuclear generation. It is quite conceivable that the capacity factor of a nuclear plant could fall below 90% in any given year, particularly when an outage is required for

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173 79 Fed. Reg. at 34,867.

174 The EPA acknowledges that “[h]ydropower is considered a renewable energy resource because it uses the Earth’s water cycle to generate electricity.” EPA, Clean Energy, Hydroelectricity. Available at http://www.epa.gov/cleanenergy/energy-and-you/affect/hydro.html.

175 79 Fed. Reg. at 34,871.
By incorporating nuclear generation in this way, EPA is penalizing rather than rewarding states that have nuclear generation.

Instead of applying a generic “at-risk” factor to all existing nuclear generation, EPA should apply a site specific “at-risk” factor where nuclear generation is really at risk. With the current approach, EPA is diluting impacts where nuclear generation is actually “at risk” and creating issues where it is not at risk, such as in Arizona. The U.S. Nuclear Regulatory Commission approved the extension of all three PVNGS units by an additional 20 years. Unit 1 is permitted to operate through 2045, Unit 2 through 2046, and Unit 3 through 2047. Given this lack of risk, at a minimum, EPA should remove the “at-risk” nuclear component from the goal calculation for Arizona.

APS, the operator of PVNGS, developed a concept for how EPA could provide even more meaningful credit to nuclear generation in its Proposed Rule that would not dramatically change the CO₂ goals. SRP supports APS’s proposed approach as a more appropriate methodology for incorporating nuclear generation into the CO₂ goals. The proposal has two components:

1. Remove the 5.8% nuclear component from the denominator of the EPA’s CO₂ goal calculation.

2. When demonstrating compliance with the CO₂ goals, allow states to take credit for a portion of annual nuclear generation in excess of the average historical performance of the fleet. The average capacity factor of a nuclear unit over its lifetime is approximately 80%. Therefore, beginning in the first compliance year associated with the rule (2020), and in each year thereafter, if a nuclear unit exceeds 80% capacity factor, allow any generation in excess of that 80% capacity factor threshold to be included in the denominator of the CO₂ emission rate calculation, which would provide credit towards compliance with the state’s CO₂ goals.

SRP urges EPA to consider adopting the proposed approach described above. This alternative approach would ensure states with nuclear generation are not unduly penalized, as well as provide those states with a meaningful incentive to keep nuclear EGUs online and operating.

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176 For example, in 2011 and 2012, the Nuclear Energy Institute indicates that the U.S. nuclear capacity factor was 88.9% and 86.4%, respectively. Available at http://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants/US-Nuclear-Capacity-Factors.

177 See APS comments for an explanation of how this value was derived.
EPA Alternative Approach to Establishing State RE Targets

EPA has developed an “Alternative RE Approach” to setting the Building Block 3 portion of a state’s interim and final goals that relies on the technical and market potential of new RE. According to the “Alternative RE Approach Technical Support Document”:

“...the Alternative RE Approach compares each state’s RE technical potential against its existing RE generation. For this purpose, EPA has utilized technical potential as measured by the National Renewable Energy Laboratory (NREL) and existing RE generation as reported by EIA for 2012. The comparison of RE technical potential to existing RE net generation yields – for each state and for each selected RE technology – a proportion of achieved renewable generation from technical potential, which can be represented as an RE development rate. For example, if a given state had 5,000 MWh [megawatt-hour] of solar generation in 2012 and a solar generation technical potential of 50,000 MWh, then that state’s solar RE development rate is 10%.”

SRP has reviewed this alternative approach and does not support its application to goal development in Arizona. SRP’s concerns with the approach are summarized as follows:

• If the alternative approach were adopted, Arizona’s emission rate goals would likely be lowered further, thereby increasing the state’s burden to achieve compliance with a 111(d) plan.

• This approach includes an assumption that states can accelerate construction of new RE and these resources would be available to lower emissions intensity by 2020. Arizona’s ability to construct additional new RE by 2020 is subject to many of the same constraints identified for implementation of Building Block 2.

• The utilization of “technical potential” is problematic as application of this type of metric is generally done without regard to items such as grid limitations, cost, land use constraints, and double counting if the same site is used for two different technologies.

• EPA attempts to address this limitation by basing the alternative RE goals on the lesser of the “technical potential” and a “market potential” assessed using IPM. However, it is unclear how EPA derived the $30/MWh reduction assumed in the IPM analysis in costs for new renewable generation. Even though EPA indicated that this cost reduction “represent[s] the avoided cost of other actions that could be taken

instead to reduce power sector CO₂, and [intended] to reflect continued reductions in RE technology costs”¹⁷⁹, and that the $30/MWh cost reduction is “consistent with the estimated cost of the proposed approach (up to $40 per metric ton of CO₂)”¹⁸⁰, a $30/MWh cost reduction for renewables would be equivalent to much higher implied CO₂ prices (about $70/ton in a market with natural gas on the margin ¹⁸¹).

SRP also does not support the “regional” approach to setting the RE portion of state goals that EPA suggested in the NODA, as this option would also have the effect of increasing goal stringency – even more so than under the two alternatives included in the June proposal.

In addition to reviewing EPA’s proposed approaches for incorporating Building Block 3 into state targets, SRP has reviewed a Policy Brief recently released by the Union of Concerned Scientists (UCS).¹⁸²

The UCS expresses concern that EPA’s 111(d) proposal does not require enough renewable energy development. UCS suggests that EPA modify its proposal for calculating Building Block 3 by using a “Demonstrated Growth Approach” for setting state renewable energy targets. Under this proposal, EPA would apply to each state a growth rate for renewable energy development that is in line with a benchmark growth rate established in the years 2009 to 2013. The total share of renewable generation for any state would be capped at 40% of total electric sales.

SRP does not support the UCS proposal for the following reasons:

- Use of the 2009-2013 growth rate may overestimate the ability of states to develop renewable resources in the long term. The renewable development growth rate over this period reflects an unprecedented build out of renewable energy, helped in

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¹⁸⁰ Id. at 3.

¹⁸¹ EPA appears to be implying that imposing a cost reduction for renewables of $30/MWh is equivalent to adding a future cost of $30/MWh to the market price of electricity, similar to a CO₂ allowance price. To test the reasonableness of EPA’s statement, the CO₂ allowance price associated with a $30/MWh cost adder was calculated for comparison with the EPA’s $40/ton cost. The calculation assumes that natural gas units set the market price. Assuming an average heat rate for natural gas units of 8,000 Btu/KWh, and a CO₂ content of natural gas of 117 lb/MMBtu, the $30/MWh additional cost equates to a CO₂ allowance price of $70/ton ($30 MWh / (8 MMBtu/MWh x 117 lb/MMBtu / 2,200 lb/ton) = $70/ton), which is much higher than EPA’s $40/ton cost.

large part by a drastic reduction in prices due to a large economic contraction and a
global supply glut.

- The proposal requires states that have made early efforts in expanding renewable
energy development to do even more. The proposal would lower the interim and
final goals in these states and constrain the limited flexibility to use other building
blocks to achieve compliance.

- Under the UCS proposal, the western region would be required increase renewable
energy generation from approximately 14% of retail sales to approximately 31% of
retail sales.

- The proposal assumes compliance would be facilitated by an unlimited REC market,
which is inconsistent with the current EPA proposal.

7.4 Building Block 4 – Demand-Side Energy Efficiency Measures

With this building block, EPA reduces emissions from affected fossil-fired generation units in
the amount that results from the use of demand-side EE measures. EPA contends that if
incentives exist to shift generation to lower carbon-intensity sources, and those sources are
then fully utilized, reducing electricity demand can produce further reductions in carbon
intensity. EPA states the agency has not assumed any particular type of demand-side EE policy.

Savings from EE programs are cumulative, meaning that a state in which a sustained program is
implemented with a 1.5% annual incremental savings rate could expect cumulative annual
savings of approximately 1.5% after the first year, 3.0% after the second year, and so on.
Savings from the first year would drop off at the end of the average life of the EE program
portfolio (assumed to be ten years by EPA).

For states already at or above the 1.5% annual incremental savings rate (based on 2012
reported data), EPA estimated that they would realize a 1.5% rate in 2017 and maintain that
rate through 2029. According to EPA, Arizona’s incremental savings as a percent of retail sales
in 2012 was 1.61%, with cumulative savings in 2012 of 5.39%.

SRP agrees that some EE measures are a viable means of managing energy consumption, which
in turn helps reduce CO₂ emissions. EE is an important component of the toolbox states can
use in their 111(d) compliance plans. However, EPA must consider the realistic constraints on
EE in assessing how it should be accounted for in calculating the state goals.

(a) EPA Should Establish Achievable EE Savings Values

As described in the Proposed Rule, EPA relied on the EIA Form 861 dataset to identify the
impacts of EE programs to date. EIA Form 861 collects total retail sales and EE program results on an annual basis, allowing EPA to calculate the annual incremental savings as a percent of retail sales by EE programs.

EPA identified Arizona as one of the top performers in the country and utilized Arizona’s performance over the last few years to outline the “Best Practices Scenario” for establishing targets for other states. As a result of Arizona’s strong performance in the past, its annual incremental energy savings assumption was set at the highest level, 1.50% of retail sales. This annual savings assumption is expected to be achieved in years 2017 through 2030 in the EPA goal setting calculation.

These levels are likely not achievable over the long-term, and even less likely on a cost effective basis. By 2020, the Energy Independence and Security Act 2007 lighting standards will be fully implemented, leaving utilities with little, if any, opportunities to take advantage of residential or commercial lighting measures. Advancing building energy codes also will deplete the savings potential of residential and commercial new construction programs as they strive for net-zero energy consumption by 2030.

Furthermore, achieving 1.50% in later years will likely come with a substantial increase in portfolio costs. By their nature, EE measures typically require a substantial upfront investment in exchange for savings that accrue over the lifetime of the deployed measure. As discussed above, aggressive codes and standards will diminish savings potential and limit the number of measures that are cost-effective for the customer and the utility. The EE assumptions used in the goal setting calculations need to be set at more realistic and reasonable levels since energy savings will be more challenging to deliver over the next 15 years as markets mature and federal equipment standards erode potential creditable savings.

EPRI likewise has similar concerns, as noted in their comments on the Proposed Rule.

“The level of energy efficiency performance in this proposed rulemaking – 1.5% annual incremental electricity savings as a percentage of retail sales – is greater than EPRI’s assessment of energy efficiency program potential. EPRI research indicates that achieving this level of energy efficiency will require[d] the addition of measures beyond energy efficiency programs and will occur over a longer period and at a higher cost than suggested in the proposed rule and accompanying RIA. While efficiency improvements in end-use devices and advances in controls technology can lead to energy savings; economic, market, and perceptual barriers can inhibit or curb customer adoption.”

EPRI Comments at 5.
Based on research conducted by EPRI, which was published in their “U.S. Energy Efficiency Potential Through 2035” study and discussed in their comments on the Proposed Rule, the level of achievable incremental savings values is much lower than the 1.50% value proposed by EPA. Specifically, EPRI’s study “indicates an achievable range of energy efficiency potential from programs equivalent to an annual incremental electricity savings of 0.5% to 0.7% of retail sales through 2035.”SRP recommends that EPA take this research under advisement when establishing energy efficiency savings values for use in the goal setting calculations.

(b) EPA Must Allow Inclusion of All EE Programs and Initiatives

Over the past several years, SRP has developed and grown a portfolio of EE programs that include more than twenty program offerings that fit into multiple categories. SRP’s portfolio of programs is designed to allow all customers to participate in EE programs to help manage energy usage and costs. Through the refinement of SRP’s SPP in 2011, EE offerings were expanded to include behavioral programs and market transformation initiatives, such as SRP’s Energy Scorecard, building energy codes, and appliance standards. The intent of these additions is to capitalize on new, cost-effective program alternatives and position SRP to meet more aggressive long-term EE goals.

For example, M-Power is a prepay program that uses in-home display monitors, smart cards, and a payment kiosk network to put consumers in control of many aspects of their energy use, payments, and budget. As a result, analysis indicates M-Power customers, on average, reduce their annual energy consumption by 12%. They are able to realize these reductions by:

- Monitoring electricity usage with real-time information;
- Managing the cost of consumption to meet personal needs; and
- Using in-home displays that provide positive reinforcement and immediate feedback about energy usage.

M-Power is unique in that few, if any, other utilities have similar participation levels and savings effects from behavioral programs of this type. Roughly 40% of SRP’s reported annual savings is currently attributed to the behavioral conservation impact of customers on M-Power. Due to its significant contribution to SRP’s EE portfolio and its extreme cost-effectiveness, programs like M-Power must be recognized as legitimate options.

In the Proposed Rule, EPA states that it does not intend to limit the types of demand-side EE measures and programs that can be included in a state plan provided that supporting

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184 EPRI Comments at 25.
evaluation, measurement, and verification (EM&V) is rigorous, complete, and consistent with EPA requirements and guidance established for moderately or well-established evaluation approaches. According to EPA classifications, most of SRP’s EE programs appear to fall into the moderately or well-established categories with the exception of the M-Power and Energy Scorecard behavioral programs. Limiting eligible EE measures to a pre-defined list of well-understood program types would potentially eliminate significant savings attributable to SRP’s current programs and would hamper future program growth strategies. As such, EPA must not exclude these types of programs.

In addition to including all existing programs and practices, EPA must establish an easy, straightforward, and timely method states can use to modify existing EE programs and add new programs to its state plan without relying on EPA approval of these programs before they can be implemented. Otherwise, adoption of new technologies, measures, and programs will be constrained and could result in a state’s inability to utilize EE programs to meet its CO₂ reduction requirements. This flexibility will be especially important as the existing EE programs are more fully subscribed in future years.

(c) EPA Must Allow States to Determine Appropriate EM&V

While EE program implementation and evaluation is well established within the utility industry, the standard evaluation protocols and accounting methodologies may not be well understood by the state environmental regulatory agencies that will be charged with development and implementation of 111(d) compliance plans. As such, EPA must allow states to use industry standard protocols, regularly conducted EM&V activities, third-party evaluation consultants, and annual reporting of achieved savings to properly quantify the impact of EE programs and practices.

SRP currently implements a robust EM&V approach to analyze the portfolio of residential and commercial EE programs it offers. EM&V is necessary to systematically determine the energy and demand reductions realized by the programs by providing accurate, transparent, and consistent assessments of their performance. Results also can provide insight into how programs can be improved in performance and delivery and how they have affected the market.

The evaluation protocols used by SRP are industry recognized standards, informed by state-of-the-art evaluation approaches, consistent with technical reference manuals, such as the DOE’s Uniform Methods Project (UMP). The emerging UMP provides a straightforward framework of EE evaluation approaches applicable to utility programs throughout the United States. The methodology represents a refinement of industry knowledge that has been authored and
reviewed by recognized experts in the field.

Despite well-defined industry standards and best practices, many states use varied input values and assumptions in the actual application. Variability of assumptions can result in differences in claimed energy savings, even when the same measure is installed in otherwise identical circumstances. EPA must recognize differences in climate zones, building and housing types, and other unique market characteristics to allow varying savings values for each state and/or region. State regulatory agencies, policy makers and other stakeholders are increasingly advocating for common approaches across jurisdictions to promote greater consistency. Often there is a balance between EM&V costs and the level of rigor, with consideration given to the total portfolio of program expenditures.

Although the professional evaluation firms used by Arizona utilities implement industry best practices, the overall approach and crediting of savings differs between SRP and the other utilities, as each organization’s goals and Energy Efficiency Resource Standards are slightly different. Furthermore, SRP is regulated by its Board of Directors, whereas the investor-owned utilities are regulated by the ACC. While SRP is not overly concerned about aligning with the ACC-approved EM&V approaches, SRP does believe its elected Board of Directors should retain oversight of its EE programs.

Overall, SRP has well established EM&V processes in place, has partners with credible evaluation consultants within the industry, and is well positioned to meet the evaluation requirements set forth in the technical documents and guidelines. That said, EPA must allow the states to determine appropriate levels of EM&V for specific programs and measures included in the state’s compliance plan while utilizing industry established EM&V best practices and protocols per EPA guidance.

EPA also must provide states with reporting flexibility as different utilities have different fiscal year periods that are used to track compliance with EE targets. Utilities should not be penalized with additional record keeping and reporting simply because they use a different fiscal year period than another utility.

(d) EPA Should Provide Credit for Early EE Deployment
As contemplated in the NODA, EPA should provide a mechanism for states to obtain credit for early-action as it pertains to EE program development and implementation. Arizona utilities have implemented a series of robust EE programs and practices and should receive credit for those measures implemented between the program’s proposed baseline year of 2012 and the proposed start of program compliance in 2020. For example, EPA could provide for banking of

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185 For example, SRP operates on a fiscal year of May 1 through April 30.
MWh savings accrued during this period and allow use of the savings to demonstrate progress towards a state’s goal. Such credit would provide an incentive to continue to pursue cost-effective EE programs prior to the implementation date.
8. SRP CONCERNS REGARDING STATE COMPLIANCE PLAN DEVELOPMENT AND IMPLEMENTATION

8.1 EPA Must Extend the Timeframe for Completion of 111(d) Compliance Plans

EPA has not provided sufficient time for states to complete 111(d) compliance plans. Due to the complexity of EPA’s proposal, state regulatory agencies will need to collaborate closely with affected entities in plan development and time will be needed to complete the extensive discussions necessary to clearly identify to the satisfaction of EPA the measures that will be included in a state’s compliance plan as well as the timeline for implementation of these measures. This is particularly true in Arizona in light of the impacts that the Propose Rule would have on the state’s generation mix.

In addition to having to communicate with affected EGUs and coordinate across state agencies to develop and implement the emissions reductions mechanisms necessary to achieve the state goals, ADEQ, as the Arizona agency responsible for plan development and submittal, will need to engage with the public and other interested stakeholders, including non-governmental environmental organizations. Many states, including Arizona, also will be required to complete legislative processes or administrative rulemakings to establish plans, which will be time-consuming in its own right.186

Outside of this obvious need for additional time to prepare a valid plan, affected entities need to have sufficient time to implement the plan. Under EPA’s current proposal, states could have up to 3 years to submit a compliance plan. Assuming that EPA issues the Proposed Rule in June 2015, and that EPA receives a year to approve the plan as is currently contemplated in the Proposed Rule, affected entities that are granted full extensions for plan submittal will not have a final, approved state plan until June 2019.187 This would leave only 6 months before the start

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186 A.R.S. § 49-191 ("Notwithstanding any other law, a state agency established under this title or Title 41 shall not adopt or enforce a state or regional program to regulate the emission of greenhouse gas for the purposes of addressing changes in atmospheric temperature without express legislative authorization"); Ariz. Exec. Order No. 2012-03 (State Regulatory Review, Moratorium and Streamlining To Promote Job Creation and Retention), available at http://azgovernor.gov/dms/upload/EO_062612_2012-03.pdf.

187 Within the Presidential Memorandum regarding Power Sector Carbon Pollution Standards issued on June 25, 2013, the President outlines expected targets for completion of major milestones under the rule including issuing final standards no later than June 1, 2015 and state plan submittal no later than June 30, 2016. Within the rule proposal, EPA indicates they will take one year to review those plans so that states have a final determination by June 2017; hence, 2 ½ years to implement in accordance with the 2020-2029 interim goal. This timeframe does not contemplate the potential for an additional 1-2 year extension to submit compliance plans if requested by the state per the extension options provided in the Proposed Rule. While the extension gives more time to complete the plan, it does not delay the rule’s compliance obligations, which begin in 2020.
of the interim goal compliance period, at which time affected entities must take actions contemplated in the plan.

EPA may argue that entities can begin planning upon release of the final rule, but the fact is that in many states, including Arizona, if adjustments are not made to current goals, compliance plans will require large capital investments in new energy infrastructure. Affected EGU owners and operators will be reluctant to initiate these investments without the certainty provided by an EPA-approved compliance plan. This is a particularly sensitive issue for utilities in the Western U.S. where planning for Regional Haze rule compliance ultimately was dictated by federal implementation plans rather than state plans. Utilities will not invest in system changes that they cannot be assured will be approved.

EPA must contemplate these constraints and propose a reasonable timeframe for submittal, approval, and implementation of a 111(d) plan.

8.2 EPA Must Clarify The Mass-Based Cap Compliance Option
SRP supports EPA’s proposal to allow states to translate their proposed emissions rate goals into equivalent mass-based goals. However, SRP has concerns about both approaches that EPA suggested in the Technical Support Document, although SRP recognizes that EPA intended this guidance to be illustrative and non-binding. In the final rule, EPA must make clear what states must provide to EPA to ensure their formula for translating the rate-based goals to mass-based goals is approvable. This guidance should ensure that all actions that reduce CO₂ emissions are counted under a mass-based program, without regard to additionality or other concerns that are not at issue under rate-based plans. EPA’s methodology should result in mass-based goals that are no more stringent than rate-based goals.

EPA’s guidance should specify acceptable analytical methods and tools, as well as default input assumptions for key parameters that will likely influence projections, such as electricity load forecasts and projected fossil fuel prices. States should be allowed to deviate from these default methods and assumptions with justification. Following the guidance would provide a streamlined path for EPA approval of mass-based emissions caps, but would still allow states the flexibility to use other approaches, subject to EPA review.

Importantly, EPA should expressly allow states to rely on unit retirements occurring after the final rule’s baseline period to meet section 111(d) goals, even if the retirement was planned prior to the Proposed Rule. EPA proposes that a state determine its mass-based target by first modeling what its emissions would be without the rule (the reference case). The state would then determine its emissions target by applying the rate-based goal to affected EGUs in its reference case. If the retirement is built into the reference case (i.e., the unit to be retired
would not be considered an affected EGU in the reference case), then the state would be unable to count emissions reductions from the retired unit toward compliance with the mass-based cap. EPA should ensure that utilities and states that have voluntarily planned retirements of existing coal-fired EGUs are not penalized by instead allowing such sources to be included as affected EGUs in the reference case.

8.3 EPA Must Provide Clear Guidance on State Plan Enforceability

The pathway a state chooses in crafting its state plan has implications for federal enforceability. EPA proposes to require that state plans include a demonstration that the emission standard therein is enforceable.

“[EPA] notes that under the CAA, measures included in an approved 111(d) state plan would be federally enforceable by EPA, and that citizens would also have the ability to file citizen suits to compel enforcement of state plan obligations, under CAA Section 304 (42 U.S.C. § 7604).”

EPA explains in the Proposed Rule that if a state wants to avoid imposing legal responsibility on affected EGUs for the entirety of the state’s emissions reduction goal, the state may elect to pursue a “portfolio approach” to compliance plan development, which would allow enforcement of requirements against entities other than affected EGUs. EPA suggests, for example, that the state could include RE and EE requirements from utility integrated resource plans in 111(d) compliance plans, as well as state or utility-established RPS and energy efficiency resource standards (EERS). EPA further suggests that by including these measures in state plans, the measures would become federally enforceable by EPA, a state, or a citizen against utilities or any other entity responsible for administering RE and EE programs.

SRP does not agree with EPA’s interpretation. First, including any requirements related to RE and EE programs would put EPA in the position of regulating retail electricity sales, over which the states (or in the case of SRP, the SRP Board) have exclusive jurisdiction. EPA cannot enforce where it does not have jurisdiction. Second, contrary to EPA’s assertion that the portfolio approach “accommodate[s] a diverse range of state approaches,” implementation of the portfolio approach requires a state to have either (i) a legally binding RPS or EERS or (ii) a vertically integrated electricity sector that engages in integrated resource planning. Both these options would be reliant on participation of the electric utility sector for emissions reductions – states do not have an alternative to regulation of the utility sector. Further, SRP sees no path in which the states can compel non-EGUs to participate in an emissions reduction program.

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189 As discussed in more detail in Section 5 of these comments, SRP is a political subdivision of the state of Arizona and the publicly elected SRP Board serves as SRP’s regulatory body. A.R.S. Title 48, Ch. 17.
applicable to EGUs. This suggests the portfolio approach is unworkable and the states could not rely on this approach in developing state compliance plans.

The issue of plan enforceability is further complicated in the event a state does not submit a plan or a state is not on track to meet its interim state goal. EPA needs to identify how it will handle such situations. As noted above, EPA does not have jurisdiction over retail sales of electricity and does not have jurisdiction to compel non-EGU entities to participate in an emissions reduction program applicable to EGUs. In light of these constraints, SRP does not believe EPA would be able to include RE and EE measures in a federal plan that replaces a state plan because it would require commandeering jurisdiction from other regulators, including the SRP Board. When EPA attempted to require state regulators to implement federal transportation control plans in the 1970s, courts held that EPA could not require state officials to affirmatively implement vehicle inspection and maintenance programs because it commandeered state agencies in violation of the 10th Amendment.190

8.4 EPA Should Give Consideration to a Regulatory “Safety Valve” to Address Electric Reliability Issues Resulting from 111(d) Compliance Requirements

EPA’s proposal currently does not include any explicit provisions to address reliability issues that might arise when states begin to implement compliance plans. SRP believes that, in addition to incorporating the solutions proposed by these comments, EPA should consider adding a provision that would give affected sources a regulatory “safety valve” in the event sources scheduled to be curtailed or retired under compliance plans must continue to run to support electric system reliability. Given the uncertainties associated with Arizona’s ability to meet the state’s proposed intensity goals, SRP believes there is a real possibility for reliability to be compromised, particularly in the early years of the program when EPA envisions that massive coal plant curtailments and retirements coupled with a reliance on market purchases would be necessary to meet Arizona’s interim goal.

NERC, with oversight from FERC, along with regional reliability entities, such as the Western Electricity Coordinating Council (WECC), and regional Reliability Coordinators such as Peak Reliability, in the Western Interconnection, are charged with ensuring the reliability of the bulk power system. Electric transmission system operators may experience conflict when trying to comply with both federal and regional reliability standards and EPA’s Proposed Rule, requiring a system operator to choose between compliance with reliability standards or compliance with EPA’s proposed emissions limits.

190 See Brown v. EPA, 521 F.2d 827 (9th Cir. 1975), vacated, 431 U.S. 99 (1977); District of Columbia v. Train, 521 F.2d 971 (D.C. Cir. 1975).
Conflict can arise in two ways. First, an RC can direct an electric transmission system operator to require that a generator initiate operations or continue operating to preserve the integrity and reliability of the bulk power system, which may put that generator above its CO$_2$ emissions limit. Second, WECC and NERC monitor, assess, and enforce compliance with reliability standards. Should a generator limit its operation to comply with its CO$_2$ emissions limit, the electric transmission system operator might be forced out of compliance with one or more of the reliability standards. NERC has the ability to, and often does, assess penalties for operating out of compliance with reliability standards. Notices of such penalties are filed with FERC’s Office of Enforcement.

EPA must implement a safety valve or reliability consideration in administering the compliance program under the Proposed Rule, developed in coordination with FERC, NERC, regional reliability entities, and RCs that expressly relieves a generation resource compelled to operate to maintain electric reliability from direct or indirect liability under the relevant provisions of the CAA.

NERC’s recent comments support the concept of a reliability back-stop mechanism:

“The EPA, FERC, the DOE, and state utility regulators should employ the array of tools and their regulatory authority to develop a reliability assurance mechanism, such as a ‘reliability back-stop’.”

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While SRP believes that EPA should incorporate a reliability back-stop mechanism into the final rule, this mechanism is not a substitute for the changes to the CO$_2$ goals for Arizona that SRP proposes in Section 3 of these comments. SRP strongly believes that the proposed changes are reasonable and will provide Arizona with the ability to achieve meaningful CO$_2$ reductions, but in a way that results in substantial cost savings for customers and mitigates reliability concerns.

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191 NERC, Reliability Impacts Potentially Resulting from the CPP, November 2014, at 3.
9. ADDITIONAL COMMENTS

9.1 EPA Must Comply with Section 317 of the CAA in Conducting Its Economic Impact Assessment

Under Section 317, EPA is required to prepare an economic impact assessment with respect to a section 111(d) standard before proposing that standard. Such assessment must include an analysis of the cost of compliance.\(^{192}\) EPA conducted a cost analysis, but erroneously used 2005 as a baseline year in the analysis, instead of 2012 as required under the Proposed Rule. Because emissions in 2005 were substantially higher than 2012, EPA inflated the GHG emissions reductions attributable to the rule, and thus failed to properly calculate incremental cost effectiveness.

9.2 EPA Should More Clearly Define “Affected Source”

In the Proposed Rule, EPA defines an affected EGU as a “steam generating unit, an IGCC facility, or a stationary combustion turbine that meets the applicability conditions in section §60.5795.”\(^{193}\) Within that section of the Proposed Rule, it defines an affected EGU as:

“...a steam generating unit, integrated gasification combined cycle (IGCC), or combustion turbine that meets the relevant applicability conditions specified in paragraph (b)(1) or (2) of this section.

(1) A steam generating unit or IGCC that has a base load rating greater than 73 MW (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel) and was constructed for the purpose of supplying one-third or more of its potential electrical output and more than 219,000 MWh net-electric output to a utility distribution system on an annual basis.

(2) A stationary combustion turbine that has a base load rating greater than 73 MW (250 MMBtu/h), was constructed for the purpose of supplying, and supplies, one-third or more of its potential electrical output and more than 219,000 MWh net-electrical output to a utility distribution system on a 3-year rolling average annual basis, combuts fossil fuel for more than 10.0 percent of the heat input during a 3-year rolling average basis and combuts over 90% natural gas on a heat input basis on a 3-year rolling average basis.”\(^{194}\)

\(^{192}\) 42 U.S.C. § 7617.

\(^{193}\) 79 Fed. Reg. at 34,956.

\(^{194}\) 79 Fed. Reg. at 34,954.
EPA must clarify how sources can demonstrate that they were not constructed for the purposes of supplying one-third or more of their potential electric output and more than 219,000 MWh net-electrical output to the grid.

In addition, there seems to be some conflict in EPA’s definition of affected units between the Proposed Rule and the accompanying technical support documents. Specifically, the Proposed Rule describes a 73 MW base load rating threshold for affected units as noted above, but the technical support documents reference a 25 MW nameplate capacity threshold. EPA must ensure consistency between its rule and its supporting analyses.

Finally, EPA should provide an explicit exemption for simple cycle turbines. Simple cycle turbines are a necessary aspect of renewable energy integration and regulations for these units should remain as simple and straightforward as possible. As such, EPA should provide simple cycle turbines with an explicit exemption from carbon pollution standards. If EPA is determined to move forward with regulating simple cycle combustion turbines, EPA should offer these units maximum operational flexibility, as described in SRP’s comments on the new source rule proposal (refer to Appendix J of these comments).

9.3 SRP Preliminary Comments Regarding Tribal Plans under Section 111(d)

In the Proposed Rule, EPA indicated that it intended to issue a Supplemental Proposal to establish CO₂ emission rate goals and a section 111(d) plan, if necessary and appropriate, for power plants located on tribal lands. That Supplemental Rule was issued on November 4, 2014.¹⁹⁵

SRP is the operating agent and one of the owners of NGS and is one of the owners of the Four Corners Power Plant (FCPP), both of which are located on the Navajo Nation. In the Proposed Rule for states, EPA requested comment on the approach EPA should use to create the CO₂ emission goals, how the agency should apply BSER to potentially affected EGUs on tribal lands, and whether a federal section 111(d) plan for tribes should have the option of including the EGUs in a multi-jurisdictional plan with one or more states.¹⁹⁶ As an owner of both NGS and FCPP, SRP believes it is important to provide comments to EPA on each of these issues. SRP will be providing comments on these issues and others in a separate set of comments that will be submitted on the Supplemental Proposal by the December 19th deadline.

9.4 Incorporation by Reference
SRP submitted comments on EPA’s proposed standards for GHG emissions from new EGUs (Docket ID Number EPA-HQ-OAR-2013-0495) on May 9, 2014, which are attached (see Appendix J of these comments). Furthermore, SRP submitted comments on EPA’s proposed carbon pollution standards for modified and reconstructed EGUs (Docket ID Number EPA-HQ-OAR-2013-0603) on October 16, 2014, which are attached (see Appendix L of these comments). SRP also intends to submit comments on the Supplemental Proposal to establish carbon standards for existing EGUs on tribal land by the required due date. Each of these sets of comments is incorporated by reference, as EPA has included many ideas and principles that are cross-referenced between each of the rules.

In addition, SRP supports and incorporates by reference those comments filed by organizations of which SRP is a member including CICS, UARG, AUG, EPRI, the American Public Power Association, the Large Public Power Council, and Western Energy Supply and Transmission Associates.
10. CONCLUSION

SRP appreciates the opportunity to provide comments regarding the Proposed Rule. As demonstrated by its existing commitments to reduce carbon emissions intensity, SRP believes it is possible to accomplish meaningful change to the country’s carbon intensity. SRP is willing to share in this effort, but this change must be undertaken in a manner that appropriately manages economic impacts and protects reliability for all electricity customers.

Notwithstanding SRP’s significant concerns with the legality of the Proposed Rule, SRP believes there are solutions available to address the problems associated with EPA’s currently proposed interim and final goals for Arizona that will moderate the impact of the rule on Arizona while still achieving meaningful emissions reductions. If EPA recognizes and implements solutions proposed by SRP in these comments, the impact to SRP’s customers would be $2.4 billion less than if SRP were forced to implement the rule as proposed by EPA. Beyond these significant cost savings, it is important that EPA support a rational path for carbon reductions that fully accounts for the complex structure of the country’s current electric generation and transmission grid, natural gas supply network, and the recent infrastructure investments mandated by EPA through other CAA regulations.

Rather than mandating enforceable interim goals, EPA should give states discretion to develop individualized plans for the 2020-2029 time period that set a state on a compliance path to meet their 2030 emission goals. In particular, EPA should allow each state to make its own determination as to which measures can be implemented on a timetable that is manageable for the state, but leads to achievement of the 2030 goals.

SRP also urges EPA to allow Arizona to consider remaining useful life in development of the state’s emission reduction plan. This action would recognize the value of significant commitments to emissions reductions that have been made to address other CAA requirements and avoid early retirement of coal-fired EGUs with significant remaining asset value.

Specifically, EPA should adjust the assumptions made under Building Block 2 consistent with a recommendation developed by the AUG. The AUG recommended a few targeted changes to Building Block 2 calculations that would result in a final rule that: (1) does not threaten electric reliability; (2) still obtains substantial reductions in carbon emissions both in Arizona and nationwide; and (3) would be substantially more cost-effective and attuned to the statutorily-mandated “remaining useful life” concept. These changes include the following:

- 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:
January 1, 2020;

January 1 of the year following 40 years after initial commencement of operation; or

January 1 of the year following 20 years after commencement of operation of significant air pollution controls at any EGU if installation occurred prior to issuance of the final 111(d) rule, or after commencement of operation of SNCR or ESPs at an EGU owned by a small utility, as defined by FERC, if installation occurred prior to the first year of the compliance period (i.e., 2020).

- For coal-fired EGUs that either shutdown or convert to natural gas-fired operation, redispetch 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.

- Coal-fired EGUs that do not redispetch prior to January 1, 2030 remain coal-fired EGUs for purposes of calculating the interim and final goals.

Finally, a significant portion of SRP’s renewable generation is from out-of-state resources. It is imperative that EPA clearly identify in the guidelines to states in the final rule that affected sources have the ability to include out-of-state renewable resources in compliance plans. The ability to invest in renewable resources, both in-state and out-of-state, allows utilities to engage in more cost-effective development of these resources and promotes greater diversity of resource portfolios.

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197 Significant air pollution control equipment includes selective catalytic reduction systems, baghouses, or flue gas desulfurization systems.