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Chuck D. Barlow
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December 1, 2014

Via Federal eRulemaking portal at http://www.regulations.gov

Via email: A-and-R-Docket@epa.gov

United States Environmental Protection Agency
EPA Docket Center, EPA/DC
Mail Code 28221T
Attn: Docket ID EPA-HQ-OAR-2013-0602
1200 Pennsylvania Avenue N.W.
Washington, DC 20460

Re: Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units issued by the Environmental Protection Agency (EPA or Agency) in Docket No. EPA-HQ-OAR-2013-0602, 79 Fed. Reg. 34,830 (June 18, 2014)

Dear Sir or Madame:

Please find attached the comments of Entergy Corporation regarding the above-referenced proposed rule. Please contact me if you need additional information regarding this filing.

Sincerely,

Chuck D. Barlow
Vice President, Environmental Strategy & Policy

CDB/sas

Attachment

Via Federal eRulemaking portal at http://www.regulations.gov

Via email: A-and-R-Docket@epa.gov

Docket No. EPA-HQ-OAR-2013-0602

Comments of Entergy Corporation to the United States Environmental Protection Agency's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34830 (June 18, 2014)

December 1, 2014

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Entergy Services, Inc., on behalf of Entergy Corporation and its subsidiaries (collectively "Entergy"), submits the following comments in response to the U.S. Environmental Protection Agency's ("EPA's") proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34830 (June 18, 2014), pursuant to the federal Clean Air Act, 42 U.S.C. section 7411(d), ("section 111(d)").

I. Introduction

Entergy is an integrated energy company engaged primarily in electric power production and retail distribution operations. Entergy owns and operates power plants with approximately 30,000 megawatts of electric generating capacity, including more than 10,000 megawatts of nuclear power, making it one of the nation's largest nuclear generators. Entergy delivers electricity to 2.8 million utility customers in Arkansas, Louisiana, Mississippi, and Texas and owns and operates wholesale electricity generating units in Massachusetts, Michigan, New York, Rhode Island, and Vermont. Entergy has annual revenues of more than $11 billion and approximately 14,000 employees.

In an effort to streamline the presentation of its comments on the Proposed Rule, Entergy adopts and incorporates herein the comments filed by the Edison Electric Institute ("EEI"), the Coalition on Innovative Climate Solutions ("CICS"), the Nuclear Energy Institute ("NEI"), and the Class of '85 Regulatory Response Group ("Class of '85"). Entergy has participated in the development of the comments of these organizations, of which Entergy is a member. Entergy also notes that entities such as the North American Electric Reliability Corporation ("NERC"), the Midcontinent Independent System Operator ("MISO"), and the Electric Power Research Institute ("EPRI") have provided analysis of the Proposed Rule and/or comments to EPA that provide an important part of the stakeholder dialogue on this topic. Entergy discusses the NERC report below in part, and a copy of the report is attached to these comments as Attachment 5.

Additionally, Entergy provides the following comments. In the event that any statement in comments adopted and incorporated herein conflicts with a statement made specifically by Entergy in this document, the statement made in this document represents Entergy's position.

II. Executive Summary

Entergy has been a leader in advocating for comprehensive climate change mitigation and adaptation policies for well over a decade; however, Entergy opposes the Proposed Rule and urges EPA to withdraw the Proposed Rule and to re-propose it, if at all, with significant revisions as discussed in these comments. The Proposed Rule exceeds EPA's legal authority under section 111(d) of the federal Clean Air Act, violates several critical principles of effective climate change policy, introduces reliability risks, and suffers from other legal infirmities that render the Proposed Rule arbitrary and capricious.

Entergy objects to EPA's proposed definition of the "best system of emission reduction" ("BSER") and its application in a section 111(d) program.[1] Of the proposed Building Blocks that represent EPA's view of BSER and the state interim and final goals under section 111(d), only Building Block 1 arguably is within EPA's statutory authority. EPA's proposed 6% heat rate reduction at coal burning units, however, is neither feasible nor cost-effective for Entergy's few coal units. EPA should delegate to the states the requirement to establish inside-the-fence efficiency improvements on a case-by-case basis, the process that is envisioned by section 111 itself.

Should EPA persist in setting standards based on its BSER definition and the Building Blocks identified in the Proposed Rule,[2] EPA should strive to make the state goals fair, achievable, and economically rational. At a minimum, EPA should make changes to the Proposed Rule to remedy five major flaws:

a. The interim standards proposed by EPA cannot be met while maintaining reliable service in the Entergy region. The interim goals should be removed from the Proposed Rule. Alternatively, the interim goals should

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[1] The substance of these concerns is discussed in the incorporated comments of CICS, Class of '85, and EEI.

[2] EPA sets its proposed state goals in terms of net generation, but requests comment on whether the goals and reporting requirements should be expressed in terms of gross generation instead. 79 Fed. Reg. 34894-34895. Entergy believes that EPA should retain the use of net generation numbers so that any efficiency improvements that are available in a unit's auxiliary equipment and pollution control devices would be reflected in reported emissions per megawatt ("MW").

be phased in over a reasonable timeline, or EPA should allow each state the flexibility to determine its own glidepath to the final goal.[3]

b. The Proposed Rule does not provide adequate incentives for states to support the continued operation of existing zero emission resources, in particular nuclear generation. The proposal should be modified to provide these incentives through provisions that tighten standards if existing nuclear units close for certain (primarily economic) reasons, provide additional credit to states in compliance demonstrations for nuclear unit performance, treat nuclear power uprates and license renewals as new generation, or all of the above.

c. The proposed standards give no credit for early action to reduce or offset carbon dioxide (CO_2) emissions, which, in Entergy's case, has been substantial. EPA should revise its baseline year or period in the Proposed Rule and/or allow the use of fleet emission averaging to provide states credit for earlier beneficial actions taken by affected entities and units.

d. The Proposed Rule does not provide requisite clarity or sufficient incentives for states to convert to mass-based standards and to engage in regional compliance, and the recently released technical support document seems to exacerbate this problem. The Proposed Rule also does not recognize that regional power markets and balancing authorities do not match state geographic boundaries. Many states are split among multiple balancing authorities and will require 111(d) planning flexibility and guidance to comply with the rule.

e. The calculation of the proposed standards in the Entergy utility region is based on inaccurate data and/or flawed methodologies, which results in interim and final emission rate standards that are unrealistic and overly

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[3] Entergy notes that, as discussed further in comments filed by CICS, section 111(d) of the Clean Air Act limits EPA's authority to developing a process "under which each state shall submit a plan to the Administrator which (A) establishes standards of performance . . . ." 42 U.S.C. §7411(d)(1). This process is to "permit the state in applying a standard of performance [which has been developed by the state, per the language above] to any particular source to take into consideration, among other factors, the remaining useful life of the existing source to which the standard applies." *Id.* The Proposed Rule does not comport with this statutory structure.

stringent. The proposed standards also do not treat renewable potential and natural gas combined-cycle ("NGCC") potential in comparable fashion. While renewable potential is assessed on a regional basis (although the regions used do not match power market boundaries), NGCC potential is assigned strictly on a situs basis, with disparate results for the Entergy region.

The remainder of these comments is organized as follows. First, Entergy provides background on the company's extensive actions to address climate change, both through its generation investments and in the policy realm. As part of these comments, we describe the policy principles which United States carbon policy should meet and how the current Proposed Rule departs from that policy. Second, the comments point to incorporated industry group submissions demonstrating that the Proposed Rule exceeds EPA's statutory authority. Next, the comments discuss why the Building Block 1 portion of the standard, while arguably within EPA's authority, is neither feasible nor supportable for Entergy's coal units. The comments then discuss each of the five major flaws that must be remedied if EPA persists in promulgating a rule which goes beyond Building Block 1 and provide specific comments on the actual language of the Proposed Rule. In each of these areas, we make specific recommendations as to how the Proposed Rule should be modified.

III. Entergy and Climate Change; Climate Change and 111(d)

For approximately fifteen years, Entergy has been a leading voice among United States electric generating companies raising concerns about the reality of anthropogenic climate change and the need for both preventative and adaptive measures to ameliorate its impacts. In 2001, Entergy was the first U.S. utility to commit voluntarily to stabilizing CO_2 emissions as part of its efforts to address the business risk posed by climate change. At the time, Entergy's CO_2 emissions were increasing at approximately 4% per year as Entergy grew its business. In 2001, Entergy set greenhouse gas stabilization and reduction goals, which it has updated periodically. Entergy's commitment is to maintain CO_2 emissions from Entergy-owned power plants and controllable power purchases through 2020 at 20% below 2000 levels. Through year-end 2013, Entergy's cumulative emissions since 2001 are 9.8% below our cumulative 2001-2013 target.[4] Through significant investments (both unit purchases and self-build projects) in nuclear and natural gas generating units, Entergy today has a much cleaner, lower emitting, diverse fuel mix than it did in 2000. Since 2000, Entergy has reduced its CO_2 intensity (emission rate) by 42%. *See* details in Attachment 1.

To put this into a global perspective, if the rest of the world operated its electric generating units at emission intensities similar to Entergy's 2013 fleet-wide emissions rate, global CO_2 emissions from the power sector (as predicted by World Energy Outlook 2013) would be reduced by approximately 54%. This, in turn, would achieve approximately 89% of the global emissions reduction needed by 2030 from the electric generating sector (that sector's proportion of an economy-wide reduction) to reach an emissions level many scientists say is necessary to avoid warming of over two degrees centigrade.[5] In other words, by simply emulating Entergy's current emission rate, the global electric generating sector would obtain 89% of the emissions reductions needed from that sector to reach a 2030 goal of no more than two degrees warming.

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[4] Entergy's 2013 greenhouse gas inventory is verified to the International Organization for Standardization 14064.1 Standard for GHG Inventory Development, Reporting and Verification by a third-party auditor.

[5] The World Energy Outlook 2013 Annex A, "Tables for Scenario Projections," provides forecasts for generation and CO_2 emissions for policy scenarios shown in the table below. "*Current Policy*" is business as usual, and "*450 Scenario*" reflects an estimate of the emissions trajectory needed to stay below two degrees C of warming. Applying Entergy's 2013 CO_2 intensity to world generation by 2030 would reduce CO_2 emissions from global power generation by 54% from the "Current Policy" scenario. Total World CO_2 emissions in 2030 in the "*450 Scenario*" is shown at 24,663 million metric tons (with 28% from power generation), where the Total World CO_2 emissions in 2030 in the "*Current Policy*" scenario is shown as 40,825 million metric tons (with 43% from power generation).

World Energy Outlook 2013 2030 Power Generation	Power Generation (TWh)	CO_2 from Power Gen (Million Short Tons)	All Gen CO_2 Intensity (lbs CO_2/MWh)
World 2030 "Current Policy"	36,224	19,559	1,080
World 2030 "450 Scenario"	30,182	7,554	501
World 2030 "450 Scenario" at Entergy CO_2 Intensity	30,182	8,904	590

During the last decade, Entergy developed a set of principles about how comprehensive greenhouse gas ("GHG") regulation should be structured at the legislative level (not as part of an EPA rulemaking).[6] The Proposed Rule does not meet these principles, and many of the actions necessary to meet those principles are far beyond EPA's statutory authority, thus demonstrating the necessity of legislative action to develop the most efficient solution to this issue as part of a comprehensive national energy policy.

First, Entergy believes that a national energy policy should include climate legislation that utilizes an economy-wide, market-based approach to find the most efficient solutions for lowering GHG emissions, likely through a strong but sustainable price signal and/or a national emissions trading program. The current proposal fails on this measure. It is not economy-wide in its emission control regime, since the proposed existing source emission standard applies only to electric generating units. The proposal lacks the market-efficiency mechanisms that a comprehensive legislative approach could include. The burden of emissions reduction is placed on the electric generating sector rather than on the economy as a whole. Although the Proposed Rule could create a price signal for emissions in multi-state 111(d) planning areas to the extent that states opt to participate, the price mechanism will continue to apply only to the electric generating sector and, indirectly, to its customers.[7]

Second, comprehensive GHG regulation should be informed by the global reality of increasing carbon emissions from existing coal units in the developing world. Energy has long held the view that climate change cannot be solved solely through energy efficiency, renewable generation, or even nuclear generation. The solution requires incentives and funding for the development of a technological retrofit solution to permit the use of coal from existing plants, particularly in the developing world, without exacerbating the GHG emissions problem on a

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[6] We note that Entergy's contributions to climate change awareness and mitigation have been widely recognized (*See* Attachment 2).

[7] Entergy is not suggesting that EPA should attempt to develop this national energy policy. To the contrary, EPA's current proposal already exceeds its statutory authority. Entergy is stating that this complex issue should be managed through a comprehensive national energy policy that is also beyond EPA's authority, and, indeed, beyond the rational provenance of an administrative rulemaking.

global scale.[8] The Proposed Rule does not fund such development in the United States, and it is difficult to see how an EPA regulation could meet this requirement.[9]

Third, Entergy consistently has supported a "pledge and review" approach that allows the United States to modify its participation in climate action if the rest of the world does not follow suit and the United States is placed at an untenable economic disadvantage. The Administration's November 12, 2014 announcement of a preliminary agreement with China to cut or cap CO_2 emissions in China and the United States, although on different timelines and to different extents, may develop into a multi-national agreement on this front. However, Entergy continues to believe that the pledge and review safety valve, which is not contained as part of the Proposed Rule, is needed as part of a national carbon policy. [10]

Fourth, Entergy believes that a comprehensive climate policy must include protection for low-income customers from the economic impact of such regulation, for instance through an increase in earned income tax credits or through a rebate/refund program. Approximately 25% of Entergy's utility customers live at or below the poverty line. This issue is a constant concern to the company and to its customers. The Proposed Rule does nothing in this respect.

It is difficult to see how any regulation developed within EPA's authority could meet the requirements of a comprehensive and meaningful energy policy as described here. EPA's attempt to develop a national energy policy founded on the slim authority of 111(d) creates the full burden of an aggressive climate policy (focused on the electric generating industry) without the ability to address the important considerations listed above.

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[8] *See* Massachusetts Institute of Technology, *Retrofitting of Coal Fired Power Plants for CO_2 Emissions Reductions* (Mar. 2009). "There is today no credible pathway towards stringent GHG stabilization targets without CO_2 emissions reduction from existing coal power plants, and the United States and China are the largest emitters. . . .China has brought on line in the last five years a coal electricity production capacity about equal to the total U.S. installed capacity. Coal will continue to be used for power generation from existing plants in both countries, so mitigation of CO_2 emissions from these plants is a high priority for research, development, demonstration, and deployment (RDD&D)." Report at 5. Available at: http://mitei.mit.edu/publications/reports-studies/retrofitting-coal-fired-power-plants-co2-emissions-reductions. Entergy co-sponsored the symposium that resulted in this report.

[9] The Administration's November 12, 2014 preliminary agreement with China may include an effort to fund carbon capture and sequestration research at some level.

[10] As discussed below, Entergy also notes that the Proposed Rule does not include a safety valve for impacts to reliability of electric generation and delivery.

IV. EPA's Limited Statutory Authority

As discussed in detail in comments adopted herein by Entergy, and specifically in the comments filed by CICS, EPA's Proposed Rule exceeds its statutory authority under section 111(d) of the Clean Air Act. Therefore, despite Entergy's historic concern about and activities regarding climate change, Entergy opposes this rule.

V. Five Major Flaws in Promulgating a Rule Beyond Building Block 1

A. The interim standards are inconsistent with reliable operations.

1. The 2020 standards cannot be met while maintaining reliable service in the Entergy region.

EPA's Proposed Rule would require Entergy's generation portfolio, and its operations as a whole, including transmission, distribution, and energy efficiency programs, to change dramatically in a very short time period. Notably, the potential impact on the generation portfolio would affect not only Entergy's coal plants, of which it has relatively few, but also its steam oil/gas units, which provide a critical reliability role in the Entergy system. The Proposed Rule develops two types of state emission rate goals, "interim" goals for the years 2020 through 2029 and "final" goals for 2030. The formula EPA uses to calculate these goals implies that all emission rate reductions from Building Blocks 1 and 2 would be realized by 2020 – the start of the interim period – or soon enough after 2020 to allow the state to meet the interim goal as an average between 2020-2029. Because it is highly unlikely that most states, including Entergy's utility states (Arkansas, Louisiana, Mississippi, and Texas), will be able in later years to have an emission rate significantly lower than the very stringent interim targets, the Proposed Rule essentially has "front-loaded" the reduction requirements.[11] This requires a steep decline in state emission rates in the first years of the interim period in states that already have invested in efficient, low emitting NGCC capacity.

[11] EPA's Notice of Data Availability ("NODA") to the Proposed Rule, released October 30, 2014, which is discussed in further detail in Section VII, below, requests comments on how Building Blocks 3 and 4 are treated in setting the state emission goals. Any possible flexibility provided in the NODA does not alleviate Entergy's concerns with the interim goals. To the extent the approaches suggested in the NODA increase the stringency of those interim targets, the NODA exacerbates the issue, the difficulties with compliance, and reliability implications.

A list of predicted 2020 capacity factors for Entergy's utility fossil units, as shown in EPA IPM model runs for the Proposed Rule, is included as Attachment 3. According to the EPA modeling, several of Entergy's fossil units that are important to reliability would close by 2020 in order to comply with the Proposed Rule.[12] In comments submitted by EEI, CICS, and others, Entergy and other industry sector members have explained in detail the infeasibility of complying with the interim standards as they are set in the Proposed Rule.[13]

Through its "Portfolio Transformation" initiative, Entergy, since 2005, has purchased nearly 3,345 MW's of NGCC rated capacity in Louisiana, Mississippi, and Arkansas, where Entergy operates five electric utility companies. In total, 13,074 MWs of installed NGCC rated capacity exists in these three states. It is largely for this reason that Building Blocks 1 and 2 make up 77% to 84% of the emission rate reductions called for in EPA's proposed emission rate goals, in turn causing this "2020 cliff" scenario. The graphics below demonstrate the 2020 cliff that Entergy utility states are facing. For Louisiana, the proposed re-dispatch of NGCC capacity results in an abrupt 54% reduction in coal fired and oil/gas capacity, for Arkansas a 64% reduction, for Mississippi a 100% reduction, and for Texas a 52% reduction.[14]

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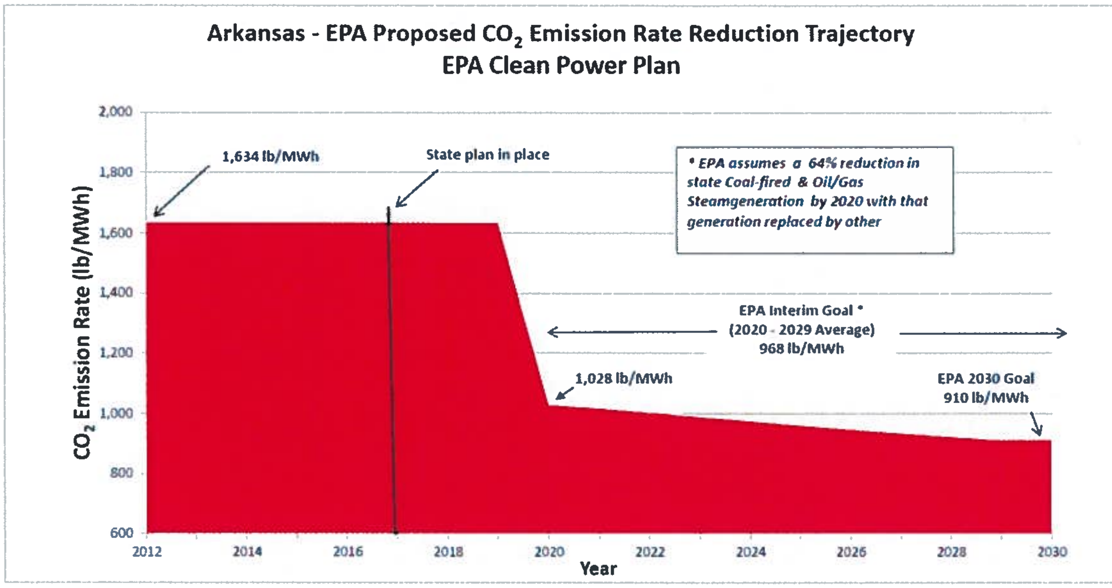
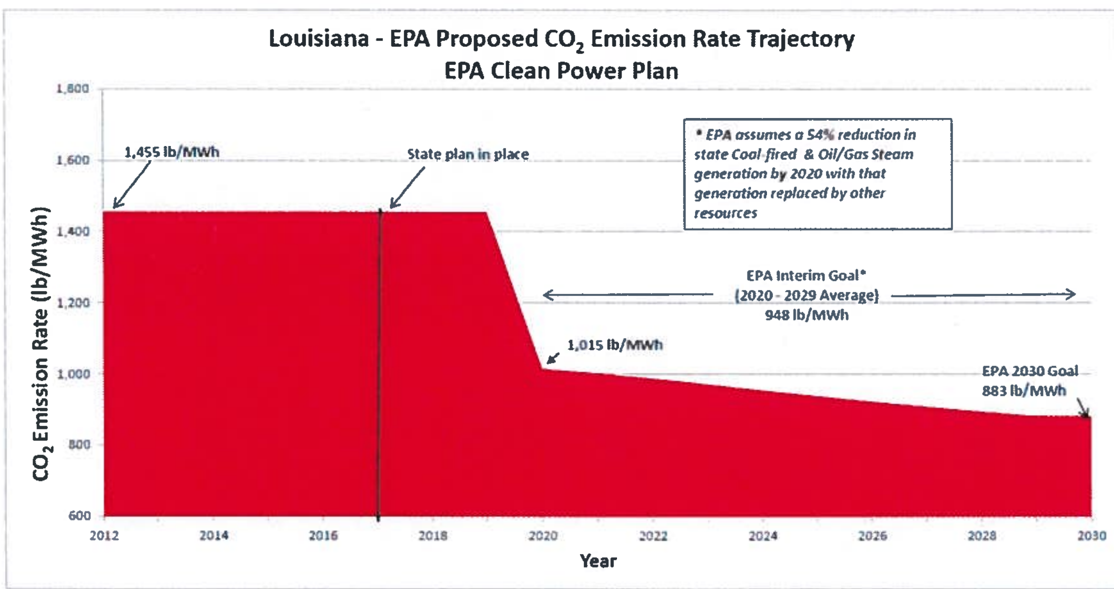
[12] Entergy oil/gas steam units in load pocket/transmission constrained areas, such as those designated as Western, West of the Atchafalaya Basin ("WOTAB"), Amite South, and Downstream of Gypsy ("DSG"), generally are considered highly important to reliable operations. These units, which EPA IPM outcomes forecast as closed or not generating in 2020, include, without limitation, Ninemile, Michoud, Lewis Creek, Sabine, and R S Nelson oil/gas steam units.

[13] MISO states: "MISO's review also indicates that the interim targets in the Proposed Rule will require significant CO_2 reductions in the 2020 timeframe. This study indicates that this short timeline may not allow cost-effective, long-term planning. If coal plant retirements are part of the compliance strategy for 2020, corresponding capacity additions (for reliability and resource adequacy) in a two-year window will be difficult, if not impossible. MISO's experience is that new gas plant construction typically requires three to six years. If new transmission and gas pipeline additions are needed to accommodate the capacity expansion, this timeline may be even longer. This finding suggests that in order to meet the 10-year average identified in the Proposed Rule, it is likely that entities will need to take immediate action. Since it is possible that state plans will not be finalized until the 2018-19 timeframe, there will be little time for decisions and implementation for infrastructure changes before 2020." MISO, *Analysis of EPA's Proposal to Reduce CO_2 Emissions from Existing Electric Generating Units* (MISO November 2014).

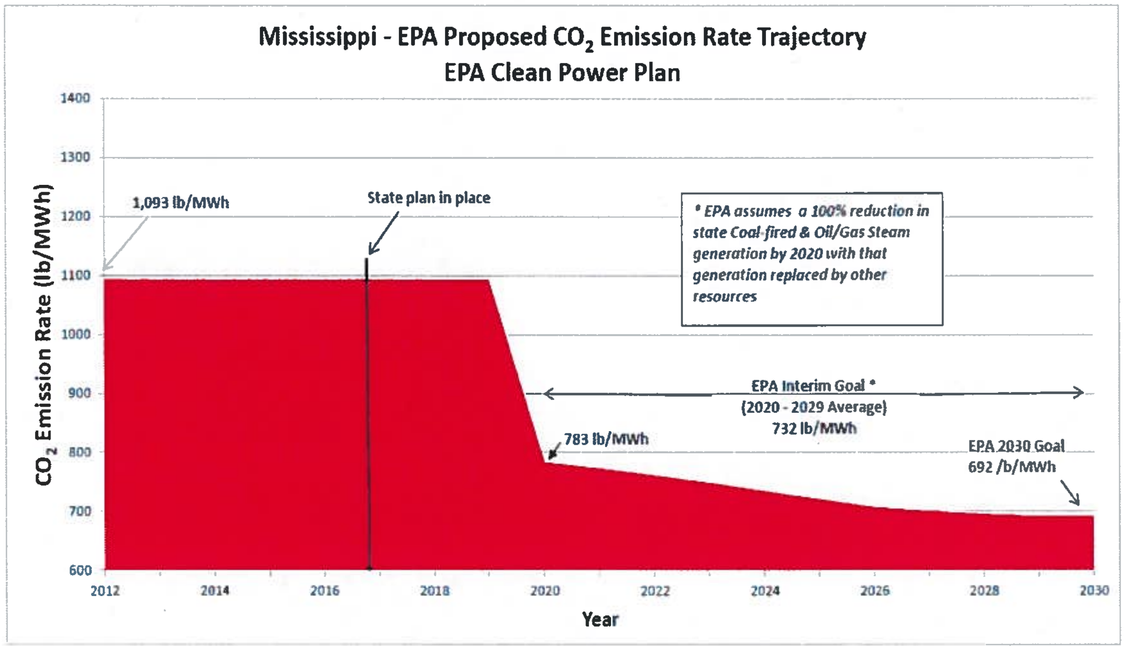
[14] Congress intended BSER to be cost-efficient and technology preserving (as evidenced, in part, by the Clean Air Act's requirement to consider remaining useful life and other factors (section 111(d)(1)). A proposed rule which forces mass unit closures is manifestly inconsistent with section 111.

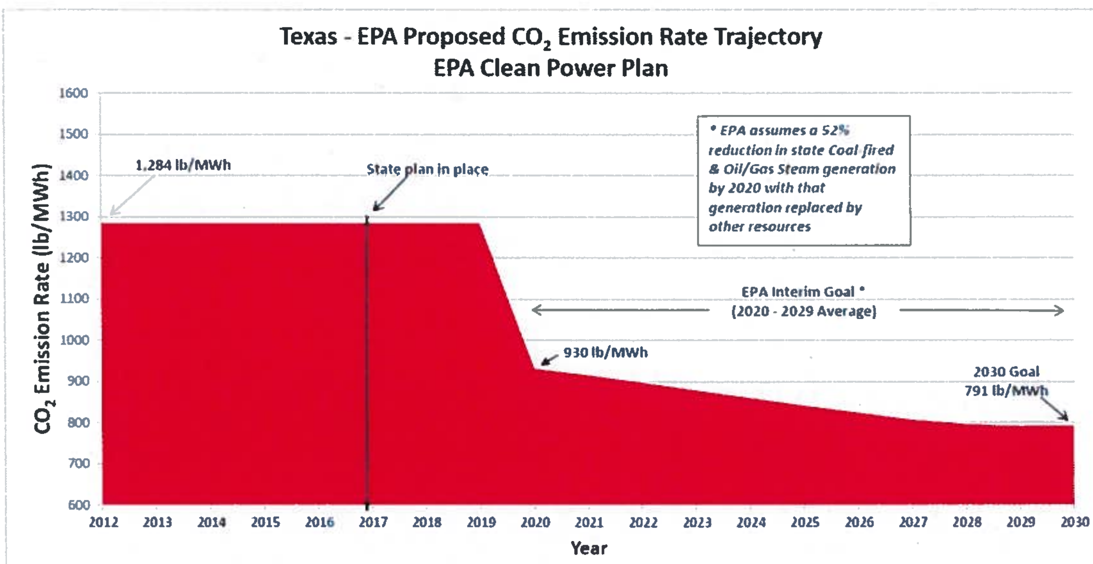


Arkansas - EPA Proposed CO_2 Emission Rate Reduction Trajectory
EPA Clean Power Plan
CO_2 Emission Rate (lb/MWh)
Year
1,634 lb/MWh
State plan in place
* EPA assumes a 64% reduction in state Coal-fired & Oil/Gas Steamgeneration by 2020 with that generation replaced by other
EPA Interim Goal *
(2020 - 2029 Average)
968 lb/MWh
1,028 lb/MWh
EPA 2030 Goal
910 lb/MWh



Louisiana - EPA Proposed CO_2 Emission Rate Trajectory
EPA Clean Power Plan
CO_2 Emission Rate (lb/MWh)
Year
1,455 lb/MWh
State plan in place
* EPA assumes a 54% reduction in state Coal-fired & Oil/Gas Steam generation by 2020 with that generation replaced by other resources
EPA Interim Goal*
(2020 - 2029 Average)
948 lb/MWh
1,015 lb/MWh
EPA 2030 Goal
883 lb/MWh





The resulting 2020 interim standards in the Proposed Rule are extremely aggressive, and EPA has not met its obligation to demonstrate that it is feasible to meet them – in particular, that they can be met while also meeting FERC and NERC reliability requirements.

EPA's primary attempt to demonstrate the feasibility of the Proposed Rule is the agency's IPM modeling of the year 2020, which purports to illustrate an achievable "snapshot" of compliance with 2020 requirements.[15] Entergy does not believe that EPA's IPM modeling reflects a realistic picture of an electric grid that can maintain required reliability standards, partly because its representation of the electric system does not capture all transmission constraints and operational requirements. Simply put, the closure of so many units necessary to grid operations by 2020 is not feasible.

As shown in the table below, EPA's IPM modeling forecasts that by 2020 there will be 3,974 of MW rated coal capacity retired in Arkansas, 3,045 MW of rated coal capacity retired in Louisiana, 2,519 MW of rated coal capacity retired in Mississippi, and 8,728 MW of rated coal capacity retired in Texas.

	2012 EPA Nameplate/Rated Coal Capacity (MW)	**2012 EPA Coal Gen (MWh)**	**2018 EPA's IPM Base Case Coal Rated Capacity (MW)**	**2018 EPA's IPM Base Case Coal Gen (MWh)**	**2020 EPA's IPM Option 1 Coal Rated Capacity (MW)**	**2020 EPA's IPM Option 1 Coal Gen (MWh)**
AR	5,487 / 5,108	28,378,831	5,108	32,730,420	1,134	7,736,185
LA	4,727 / 4,195	24,300,393	1,732	11,235,940	1,150	5,087,979
MS	2,888 / 2,519	7,503,114	907	6,419,870	439	0
TX	25,535 / 23,822	138,705,138	22,963	153,484,020	15,094	90,746,645

[15] EPA Technical Support Document: Resource Adequacy and Reliability Analysis, pg. 1-8 (EPA description of the IPM modelling as a "demonstration that the implementation of this rule can be achieved without undermining resource adequacy or reliability"), http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-resource-adequacy-reliability.pdf.

Even a cursory inspection of EPA's IPM 2020 modeling for the Entergy region shows that the results are not viable. To meet the 2020 standards, EPA's IPM shows Entergy closing or not operating a large number of steam gas units that play a critical reliability role on the Entergy system because they are in transmission constrained areas and five baseload coal units.[16] Several independent studies, including one undertaken recently by MISO regarding voltage and local reliability ("VLR"),[17] confirm that the operation of these units is required to meet reliability requirements, and that the units cannot be shut down, and reliability maintained, without billions of dollars in transmission investments, which would take far longer to plan, site, and construct than the few years that would be available between final approval of state 111(d) plans (2017 at the earliest) and 2020.

To demonstrate the infeasibility of EPA's IPM results, and, by extension, the infeasibility of the 2020 interim goals, Entergy ran its own transmission-constrained dispatch models assuming the closure (or non-operation) of the plants consistent with EPA's IPM 2020 compliance modeling and Entergy's load forecasts from the 2013 business plan. The results were unambiguous – not only could the system not be operated in compliance with reliability requirements, but involuntary curtailments (rolling blackouts) would be required on a routine basis. Entergy's modeling of EPA's compliance scenario shows that it would result in a shortage of generation in place to serve load, causing rotating black outs on the Entergy system for approximately 100 days a year, even in "normal" weather conditions, likely during the winter and summer months.[18]

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[16] Entergy currently owns and operates 4,519 MWs of fossil-fueled generation in Arkansas projected by Entergy to be available in 2020 for generation. The EPA IPM Option 1 compliance model shows that five units will retire by 2020 (the closure of 3,861 MWs). Therefore, the Proposed Rule is modeled by EPA as closing **85%** of Entergy's fossil generation in Arkansas by 2020 or shortly thereafter. Results in Entergy's other utility service territories are similar. EPA's modeling of the Proposed Rule Option 1 shows **48%** of Entergy's fossil generation in Louisiana closing or becoming non-operational by 2020 or shortly thereafter, **68%** in Mississippi, and **100%** in Texas. In total, EPA modeling shows **68%** of Entergy's current fossil fleet (11,730 MW), otherwise projected to be operational and generating electricity, as retired or operating at a 0% capacity factor by 2020.

[17] MISO, *Planning for VLR Mitigation* (November 2014), available at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PSC/2014/20141111/20141111%20PSC%20Item%2002%20Planning%20for%20VLR%20Mitigation.pdf.

[18] When Entergy updates its load forecasts to take into account the full effect of the expected growth in industrial activity on the Gulf Coast, this number will grow to well above 100 days/year. On the other hand, the IPM/EPA modeling assumed unrealistically low load growth for the Entergy region. Even using those IPM load forecasts, the level of interruptions is 10 days per year, or 100 times the NERC standard. *See* discussion below.

To put this in context, this level of service interruption is approximately 1000 times higher than the NERC planning standard for interruption of service due to insufficient bulk system facilities (generation/transmission). The NERC standard is "one day in 10 years," meaning that system operators and load serving entities should have sufficient generation and transmission in place so that service interruptions due to lack of available generation are extremely rare. This standard does not cover outages caused by local distribution failures, storms that temporarily disrupt transmission, or similar incidents. Removing the generation that EPA's IPM says can be taken out of service would result in electric service interruptions--even with all other generation, transmission, and distribution facilities in place and operating properly--and would violate federal standards.

An important aspect of the impacts this rule could have on reliability of the electric energy supply system not considered by EPA is the vulnerabilities and challenges the system is facing from climate change and extreme weather events. In other words, a world of higher temperatures and increased storm activity logically will require more generation, not less, and more hardened and flexible (not additionally stressed) electricity delivery systems. The DOE, in its July 2013 report on vulnerability of the energy sector to climate change, stated: "Increasing temperatures, decreasing water availability, more intense storm events, and sea level rise will each independently, and in some cases in combination, affect the ability of the United States to produce and transmit electricity from fossil, nuclear, and existing and emerging renewable energy sources. These changes are also projected to affect the nation's demand for energy. An assessment of impacts—both positive and negative—is necessary to inform forward-looking efforts to enhance energy security." [19]

Significant findings from their report include:

- Thermoelectric power generation facilities are at risk from decreasing water availability and increasing ambient air and water temperatures, which reduce the efficiency of cooling, increase the likelihood of exceeding water thermal intake or effluent limits that

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[19] *U.S. Energy Sector Vulnerabilities to Climate Change and Extreme Weather Report*, DOE, July 2013.

protect local ecology, and increase the risk of partial or full shutdowns of generation facilities.

- Energy infrastructure located along the coast is at risk from sea level rise, increasing intensity of storms, and higher storm surge and flooding, potentially disrupting oil and gas production, refining, and distribution, as well as electricity generation and distribution.
- Renewable energy resources, particularly hydropower, bioenergy, and concentrating solar power can be affected by changing precipitation patterns, increasing frequency and intensity of droughts, and increasing temperatures.
- Electricity transmission and distribution systems carry less current and operate less efficiently when ambient air temperatures are higher, and they may face increasing risks of physical damage from more intense and frequent storm events or wildfires.
- Fuel transport by rail and barge is susceptible to increased interruption and delay during more frequent periods of drought and flooding that affect water levels in rivers and ports.
- Increasing temperatures will likely increase electricity demand for cooling and decrease fuel oil and natural gas demand for heating.[20]

While EPA made a high level assessment of impacts to the electric supply system from power plant retirements and the shift to different electric supply sources using EPA's IPM Modeling, it did not take into consideration scenarios incorporating the risks the electric system is facing from ever increasing risks from climate change and extreme weather events. Concluding that reliability of the electric system to yesterday's system demands is not adequate for determining reliability of an energy system that also needs to operate effectively to a changing climate.

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[20] *Id.*

In an effort to monitor climate trends effectively and to help plan for future impacts, the National Climate Assessment Development and Advisory Committee chartered the Indicators Working Group ("IWG") to create a set of physical, ecological, and societal indicators that would inform decision-makers and the public about our nation's changing climate. The IWG's specific charge was to develop recommendations for this system of indicators for consideration by the U.S. Global Climate Research Program (USGCRP) as the implementing organization. The system of indicators, as designed, includes the most important climate changes, impacts, vulnerabilities, preparedness, and mitigation responses, including changes that occur in a multi-stressor context, meaning those indicators that have both climate and non-climate stressors. These components serve as categories within which to organize an end-to-end system of indicators. The IWG issued its "Pilot Climate Change System Indicators Report" earlier this year. They said that "the development of a national system of indicators is an essential feature of such information, and provides a foundation for assessing change on an ongoing basis."[21]

Entergy participated on the IWG Energy Indicators Team and helped identify that heating degree days[22] and a stress index for generation, transmission, and distribution[23] are recommended as important indicators. [24]

Climate change impacts on electricity infrastructure include temperature changes, precipitation changes, changes in storm intensity and/or tracks, and sea-level rise. These direct

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[21] *Pilot Climate Change System Indicators Report*, http://www.globalchange.gov/sites/globalchange/files/Pilot-Indicator-System-Report_final.pdf.

[22] Direct measurements of electricity demand are difficult to obtain routinely on a regional basis. Energy demand is closely associated with heating and cooling requirements, so heating and cooling degree days are a good indicator of changes in overall energy demand as it varies with weather, and over time, as it varies with climate. Heating and cooling degree days are calculated by National Climate Data Center (NCDC) on state, regional and national levels, based on a reference of 65 degrees F, and weighted by population. Monthly averages on a regional basis and national averages are reported as current indicators with good trend information.

[23] One of the important consequences of electricity supply responses to extreme weather conditions is the number of times and extent of power outages. Outages are clearly related to conditions of extreme stress, although they are also a function of preparedness and hardiness of existing infrastructure. But even given these caveats, and given the difficulty of acquiring data, the North American Electricity Reliability Corporation (NERC) calculates a composite system reliability index (SRI), which incorporates a number of features of the electricity generation and distribution system. Values above 5.0 are considered to be "high stress" events, and the indicator chosen for the pilot is national in scale and is simply the number of days per year that the SRI exceeds this value.

[24] *Id.* at 58-63.

effects can become impacts on infrastructures and energy services and have implications for electricity supply. Entergy urges EPA to identify appropriate climate change and extreme weather event frequency scenarios and to consider the potential impacts of these scenarios on electric system reliability in concert with expected unit retirements, load pockets, and greater reliance on interruptible sources of energy. These considerations exacerbate the difficulties caused by the interim, and even the final, state emission rate standards.

As noted, Entergy's conclusions about the infeasibility of implementing the closure (or non-operation) of the plants from EPA's IPM 2020 results are based on Entergy's own load forecasts, which actually are quite conservative, as shown in the table below. The table below compares three forecasts:

(a) The load forecasts for the Entergy region from EPA's IPM modeling;

(b) Entergy's own forecasts from last year's business plan, which form the basis for the Entergy modeling discussed in these pages. These Entergy load forecasts are in the process of being adjusted upward to take into account the full extent of the planned new industrial activity on the Gulf Coast; and

(c) The load forecasts that are being developed for this year's business plan, which will reflect increased load growth expectations for the so-called "industrial renaissance" in the Gulf Coast region.

	(a) IPM Base Case Cumulative Annual Growth Rate (2016-2020)	(b) Entergy Business Plan '14 Cumulative Annual Growth Rate (2013-2016)	(c) Latest update to Entergy Forecast Cumulative Annual Growth Rate (2014-2019)
All of Entergy region	1.2%	2.0-2.25%	2.5-3.5%

Entergy also analyzed the feasibility of complying with the 2020 interim standards in a different way, without regard to EPA's IPM results. Instead, Entergy used its own transmission-constrained dispatch models to estimate how much coal-to-gas redispatch it could achieve while maintaining reliable service. Entergy then calculated the gap between the emissions rate reduction achieved through maximum redispatch and EPA's assumed improvement in coal heat rates (which, as we explain below, is not a realistic assumption) and the 2020 standards (using a range of assumptions about how the state standards would be "allocated" to Entergy electric generating units). The gap, which presumably would have to be achieved through additional use of renewables and through energy efficiency, was larger than the total potential assumed by EPA for those Building Blocks in several of the Entergy states.

2. Options for addressing reliability issues created by the 2020 interim standards

Entergy believes that EPA has several choices for dealing with this 2020 cliff issue. One choice would be to eliminate interim standards altogether and allow states to develop a glidepath where as long as the state can demonstrate reasonable further progress toward the final 2030 goal, the state will be in compliance. Entergy believes that this approach is the most appropriate way to implement the Proposed Rule. This approach would provide the most flexibility to the states, which is what section 111(d) envisions.

In addition, the incorporation of a dispatch price adder for EGU CO_2 emissions by a state could provide an optional best efforts "safe harbor" approach to establishing the glidepath. A dispatch adder would result in the efficient realization of Building Block 2 emissions reductions--redispatch from coal to gas--but would not require any facilities to be retired if they were needed for reliability. This approach would avoid the reliability problems associated with EPA's proposed interim standards, but would allow cost-effective redispatch emission reductions to be realized. Such a safe harbor would not immediately require any new transmission facilities or capital investment and would also encourage regional compliance. But, absent *clear guidance* from EPA that such an approach can be an optional basis for establishing a compliance glidepath, this opportunity likely will not be realized.

B. The Proposed Rule does not provide adequate incentives for states to support the continued operation of existing zero emission resources, in particular nuclear generation.

The scientific consensus makes it clear that a ton of CO_2 (or GHG emissions) avoided today is as important as the ton avoided tomorrow (either in 2020 or in 2030). As a consequence, the retention of zero-CO_2-emitting power generation resources currently operating is as important as the introduction of new zero-CO_2-emitting power generation resources in the future. Conversely, the potential loss of nuclear zero-CO_2-emitting power generation resources (through failure of EPA rulemakings such as this, or markets, to reflect the value of the zero-emissions attribute) means that the addition of new zero-CO_2-emitting supply serves only to offset or replace the lost nuclear zero-CO_2 generation rather than to help put the state on a pathway toward significantly lowering the overall carbon profile of its power supply.

Realistically, replacing one MW of nuclear capacity likely would require much more than a single MW of nameplate capacity from another zero-carbon resource to provide equivalent energy *and* capacity to the system. In light of the high capacity factor and baseload character of existing nuclear plants and the intermittent character of wind and solar, to obtain the same amount of energy *and* capacity from wind and solar as the energy *and* capacity of a 1,000 MW nuclear plant would require approximately 1,700 MW of wind plus another 2,600 MW of solar.[25] This amount of replacement capacity would only offset the zero-carbon power lost by a nuclear unit that were to retire, whether ahead of or concurrent with the end of its operating license. To make actual progress toward reducing the overall GHG emissions from power generation would require more renewables beyond the amount identified above. Therefore, the cost of reducing GHG emissions from the power sector will be mitigated to the extent that safely-operating nuclear plants remain in operation as long as possible under NRC regulation. Because one of the important axioms of climate change is that emissions of GHG are long-lived in the atmosphere, the goal of protecting the continued existence of zero-carbon supply today and avoiding its replacement with fossil-fueled electricity in the near term will reduce the cumulative amount of emissions into (and concentrations of GHG in) the atmosphere from

[25] This calculation assumes the following capacity factors by fuel and technology (using Energy Information Administration (EIA) capacity factors for 2012): nuclear (86.2%); wind (27.2%); solar (15.6%). The calculation also assumes the following for on-peak capacity value (based on PJM's 2012 on-peak effective forced outage factor for nuclear and its on-peak capacity ratings for intermittent wind and solar (also 2012): nuclear (98.5%); wind (13%); solar (29%). (Note that from a capacity value point of view, a 1,000 nuclear plant equates to roughly 7,575 MW of wind capacity or 3,400 MW of solar. If that much wind capacity (7,575 MW) were built, the resulting projects would supply roughly 2.4 times as much energy as the nuclear plant; if that much solar capacity (3,400 MW) were built, it would only provide about 60 percent of what the nuclear plant could provide.) The resulting estimate of 4,300 MW of wind and solar needed to replace the energy and capacity of a 1,000 nuclear plant is conservative. Had the calculation been based on PJM's actual capacity factors for 2012 (nuclear (92.4%), wind (25.7%), and solar (14.3%)), then the amount of capacity that would have been needed would be 2,000 MW of wind plus 2,500 of solar, for a total of 4,500 MW of replacement capacity and energy. Sources: EIA, 2012 capacity factors (data from Monthly Energy Review and Electric Power Annual); PJM data from Monitoring Analytics, 2012 PJM State of the Market Report, Capacity Market Chapter, Tables 4-25 and 4-29; "Characteristics of Successful Capacity Markets," Presented to APEx Conference 2013, Pfeifenberger and Spees – The Brattle Group, October 31, 2013.

United States power plants. To that end, it is essential that if the Proposed Rule incorporates zero-emission source deployment as part of BSER, it also provides support for the retention of existing nuclear units throughout the country.

Thus, Entergy urges EPA to make the following changes in its treatment of nuclear power in the Proposed Rule, if Building Block 3 remains a part of the proposal:

- Remove the 6% "at risk" MWh calculation from each applicable state's emission goal calculations, and instead create a meaningful goal-setting incentive for states to support the continued operation of existing nuclear units;[26]
- Count all post-2012 new plants and uprates toward compliance (for new plants or uprates with an in-service date during or after the baseline year or period). In other words, grant compliance credit (add MWh of generation to the denominator of a state's compliance demonstration) for the unit's output once its license extension is effective;
- Treat all units relicensed during or after the baseline year or period as new units during their license renewal period; and
- Allow states to include all nuclear generation from existing units above a reasonable historic industry capacity factor, such as 81.6%, in the denominator of compliance calculations, so that high-performing units gain compliance credit for their host states.[27]

EPA specifically requests comment on the timing aspect of whether nuclear uprates and similar zero-emission source additions to generation should be allowed to count toward a state's compliance with 111(d) goals and indicates some flexibility to this baseline year approach, likely because of the long time horizon and significant expense of planning and constructing a nuclear uprate. EPA states:

> In addition to the nuclear generation taken into account in the state goals analysis, any additional new nuclear generating units or uprating of existing nuclear units, relative to a baseline of capacity as of the date of proposal of the emission guidelines, could be a component of state plans. This baseline would be consistent with the proposed approach for treatment of existing state programs. The agency requests comment on alternative nuclear capacity baselines, including whether the date for recognizing additional non-BSER nuclear capacity should be

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[26]This issue is discussed in further detail in the comments filed by EEI and NEI.

[27] In all its calculations, EPA assumes a uniform 90% capacity factor for all nuclear power plants, existing and new. Historically, 90% is on the high end of unit performance range. The average lifetime capacity factor of the 100 nuclear plants now operating is 81.6% (through 2013), according to NEI.

the end of the base year used in the BSER analysis of potential nuclear capacity (i.e., 2012).

79 Fed. Reg. at 34923. EPA also indicates that states are given and should exercise flexibility in development of 111(d) plans that incentivize fossil emission reductions (such as those that may be created through nuclear uprates).

The inflexible use of 2012 as a single year baseline for a nuclear uprate (even the "end of the base year") is problematic. For example, Entergy completed the construction portion of a 178 MW uprate of its Grand Gulf Nuclear Station ("GGNS") near Port Gibson, Mississippi in June 2012 at an approximate cost of $874 million. From June until September 2012, GGNS continued to operate at its pre-uprate capacity while finalizing preparations for movement to the higher (post-uprate) capacity. GGNS began operations at its uprated capacity in September 2012; however, as part of the extended power uprate project, Entergy included an operational flexibility power flow mapping design called MELLA+.[28] The inclusion of MELLA+, and operation under the parameters it allows, requires an additional operating license modification approval by the Nuclear Regulatory Commission. Entergy submitted its MELLA+ license request change as a part of the extended power uprate project in the first quarter of 2014 and expects NRC approval in May 2015. These activities have delayed final close-out of this project by Entergy.

There is no basis for disallowing the states that use GGNS's capacity and electricity the benefit of applying 178 new MW of zero-emission electricity toward their compliance demonstrations merely because the construction phase of the extended power uprate project ended in September 2012 rather than in January 2013, or in February 2014, especially since other phases of project approval by the NRC have taken until after January 2014 (the rule proposal date). This is the type of issue that should be left to the discretion of the state in developing its section 111(d) plan and, indeed, in "establish[ing] standards of performance" under section 111(d)(1)(A). The substantial investment-backed decision, made by Entergy and the co-owners

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[28] MELLLA+ expands the "operating domain" for the Grand Gulf power-flow map to 115% percent (4408 MWt) of the originally licensed thermal power (3833 MWt) for core flow as low as 80% percent of the rated value. For core flows less than 80%, percent, the upper boundary of the expanded domain is approximately defined by a power-flow line that extends from 115% percent power at 80% percent flow, down to 80.6% percent power at 55% percent of the rated flow. The MELLLA+ expanded operating domain increases operating flexibility by allowing control of reactivity at maximum power by changing flow rather than rod insertion and withdrawal.

of GGNS and approved by state utility regulators through the issuance of a certificate of public convenience and necessity, likely has avoided or displaced significant fossil emissions and will continue to do so for many years to come. States should be given the flexibility to use a variable baseline year when determining which zero-emission projects can be used for compliance demonstrations.

C. The Proposed Rule gives insufficient or no credit for early action.

Entergy objects to EPA's development of a Proposed Rule under which virtually none of its industry leading early-action investments receives credit toward compliance. The proposal would create significant expenses for Entergy's customers and shareholders while ignoring the gains and commitments that the company - and thereby its customers - has made since at least 2000 in reducing GHG emissions.

We encourage EPA to devise a method that will allow banking and utilization of early action reductions dating back to Entergy's first commitment in 2001 and will allow those credits to be used for compliance in future years (*See* Attachment 1). EPA also should include a mechanism in the rule allowing affected entities to take credit for overall fleet emission rates, including nuclear generation. For example, Entergy Arkansas, Inc.'s utility fleet emission rate in Arkansas (Entergy's largest coal generation state) was 899 lbs CO_2/MWh in 2013, when nuclear generation is included.[29] By comparison, Arkansas' final 2030 emissions rate goal under the Proposed Rule is 910 lbs CO_2/MWh. EPA's 111(d) rule should develop a safe harbor that allows affected entities to show compliance with any state 111(d) plan through the demonstration of an emission rate near or below the state's emission rate goal.

D. The Proposed Rule does not provide either clarity or incentives for states to convert to mass-based standards or to engage in regional compliance.

In part because of the significant cost and reliability implications of the Proposed Rule, it is important that the final rule permit, and even facilitate, regional compliance for states that determine such a path would be appropriate. Although the Proposed Rule would allow regional

[29] Based on ownership share of generation located in Arkansas. The 2013 emission rate for all generation owned by all Entergy companies in Arkansas was 1066.

compliance, EPA does not address the reality of what is required to implement regional compliance, which requires several steps that are unclear under the Proposed Rule. These steps include (a) conversion to a mass-based goal in a manner that does not disadvantage states that choose this option, and (b) the development of state 111(d) plans in states that are "split," with part of their generation in one regional transmission organization ("RTO") and the remainder in a different or no RTO.

1. Mass-based Goal Conversion

Conversion to a mass-based standard is an essential step toward regional planning and compliance. If states want to participate in a regional approach, or continue a regional approach that is already in place (such as the nine-state Regional Greenhouse Gas Initiative), they must be able to convert to a mass-based standard; to attempt regional compliance through an averaging of individual state rates is complex and likely infeasible. The Proposed Rule is not clear on what mass-based conversion protocol would be acceptable to EPA, and, importantly, how it can provide for load growth. When a rate-based standard is used, no explicit provision for load growth is needed; it can be accommodated within the rate-based formula. But load growth must be explicitly accounted for as part of a mass-based conversion formula, or else the mass-based approach would be materially less attractive to pursue. However, the Proposed Rule is not clear on what provisions for load growth in a mass-based conversion would be acceptable to EPA, and it appears that the simple approach to a mass-based approach of multiplying a state's interim or final standard rate by the MWhs from existing generating units in the 2012 base year would make no provision at all for load growth. This ambiguity disadvantages the mass-based conversion option.

Without a clear provision for load-growth, the use of the mass-based conversion option becomes very problematic, and this will in turn discourage regional planning. EPA must remove this disincentive to regional compliance. Regional compliance offers many advantages and, as long as it is a voluntary option, it should be encouraged. In fact, Entergy is concerned that if the disincentives to regional compliance are not removed in the final rule, the results could be highly detrimental to the continued operation of organized electricity markets, which have been a proven source of great efficiency and benefit to customers. That would be a major and unnecessary step backwards. Without mass-based regional compliance, generators that currently participate in regional (multi-state) economic dispatch will have to change their method of participation, reducing dispatch efficiencies and possibly constraining the RTO's ability to redispatch to maintain reliability. In contrast, under a regional mass-based approach, an RTO can factor environmental adders into the economic dispatch, ensuring that the most cost-effective way of meeting the mass-based standard is achieved while maintaining reliability. EPA's supplemental technical support document on rate–to-mass conversion, released November 6, 2014, is not particularly helpful.[30] It provides two examples of an approach to rate-based to mass-based conversion, both of which are complex and difficult to understand.[31] More importantly, the proposed "opt-in" conversion approach appears to require greater emissions reductions in some states than EPA's own IPM modeling indicates that the rate-based standard would require. This inconsistency will likely pose a barrier to regional compliance. For example, EPA's data suggests that the rate-based approach would be less stringent than the mass-based standard for seven of the fifteen MISO states, and the mass-based approach would be less stringent for the remaining eight states. Gaining support for a regional compliance approach will be even more difficult with such conflicting incentives. Such a disincentive for mass-based conversion, and hence for regional compliance, represents a huge flaw that must be

[30] Entergy notes that this supplemental TSD is the latest in a substantial list of documents released at various times concerning the Proposed Rule since the June 2, 2014 signing of the proposal by the Administrator. This latest TSD was released by EPA fewer than thirty days prior to the December 1, 2014 comment deadline. Both this latest release, and the continual presentation by EPA of additional information on the Proposed Rule, including potential new and different interpretations of the proposal, and the numerous options and alternatives on which comment is sought in the preamble (approximately 195), violate the basic principle of administrative law that a Proposed Rule cannot be a moving target in order for the public to give meaningful comment. This rulemaking method improperly shifts the burden to the public to develop multiple versions of this Proposed Rule for analysis and to determine on which of those variants to comment. Depending on the content of the final rule, this rulemaking process may well violate the requirement of Clean Air Act section 307(d), 42 U.S.C. section 7607(d), concerning the specificity with which a rule must be proposed. Entergy also notes that this rule in many instances requires a reader to consult the Proposed Rule language, the preamble, the TSDs, and then the spreadsheets and calculations underlying the TSDs, before what EPA is actually proposing becomes clear – if then. Entergy also has encountered multiple occasions where conflicting explanations, interpretations, or applications of the Proposed Rule exist among these levels of documentation. One could also include in this list the EPA fact sheets, press releases, and public statements that accompanied the proposal's announcement and that implied a substantially different context for the rule (a baseline of 2005; a target of 30% reductions from that baseline; praise for early-action companies such as Entergy, who then get no credit for early action). Indeed, one can read the actual Proposed Rule language, then read the preamble, and wonder whether this preamble is meant to introduce this Proposed Rule. Many of the most confusing and crucial aspects of the preamble are not mentioned in the actual Proposed Rule language, or are mentioned in the barest of terms. Again, Entergy urges that this Proposed Rule be withdrawn and re-proposed, if at all, in a package that allows the public to understand what EPA is proposing and to comment in a meaningful fashion.

[31] *See* Peter Maloney, "EPA Emission Conversion Formula Not So Simple," *Platts Megawatt Daily* (Nov. 19, 2014) (https://pmc.platts.com/Article.aspx?id=cb51ebf6f-8b84-4fc4-bbc6-2785f7434f9c&nl=Megawatt+Daily&nl2=News&nl3=&nl4=).

remedied. There is no basis for requiring more stringent reductions under a mass-based approach than under a rate-based standard in any state; the mass-based approach should be transparent and of comparable stringency. If the mass-based conversion is disadvantaged, the result is likely to be not just lack of regional compliance, but significant disruptions in regional power markets. *See also* comments on proposed section 60.5770 in Section VII.B, below.

2. States With Multiple Balancing Authority Areas

In the North American electric system, balancing authorities are the entities responsible for ensuring that generation meets load every second. Many balancing authorities cover parts of multiple states, and, importantly, many states are split among different balancing authorities. The RTOs and independent system operators (ISOs) that run large regional power markets are each a separate balancing authority. This is also true for multi-state utilities that are not in RTOs. For example, the Southern Company subsidiaries are a single balancing authority, as were the Entergy operating companies before they joined MISO. In thirteen of MISO's fifteen states, including the four states in which the Entergy utility companies operate, only part of the state's electric facilities are within MISO; the remainder of the electric facilities in the state are in a different RTO or in a non-RTO balancing authority.[32] One balancing authority within a state may pursue regional compliance; another may not. EPA must recognize this reality and provide clear guidance on how 111(d) plans can be structured to accommodate two different parts of a state with two different compliance strategies.

In particular, EPA must provide states with the ability and guidance to split their 111(d) plans, as follows:

1) The ability to split the state into two or more subparts, based on balancing authorities, in the state section 111(d) plan;
2) The ability to establish goals for each subpart, such that the subparts together will meet the state standard in a manner acceptable to EPA; and
3) The ability to allow electric facilities in the state to participate in two or more different regional mass-based compliance plans, and/or the ability for part of the

[32] MISO is not unique in this respect. The Pennsylvania Jersey Maryland Interconnect ("PJM") and the Southwest Power Pool ("SPP") also have split states. Texas, individually, is in three RTOs.

state to comply through a regional mass compliance plan and the rest of the state not to do so.

EPA must make it clear that it is permissible to establish goals for different subparts of the state, and to do so, EPA should only require that the state demonstrate that compliance with the sub-goals for each region will not result in higher CO_2 emissions than would occur through compliance under a statewide rate-based standard. One example of how a state could make this demonstration would be to show that the weighted average of the subpart standards (weighted by the portion of baseline period EGU emissions located in each subpart) equals the state standard. Based on this demonstration, a state would be allowed to establish split state implementation plans ("SIPs") and submit separate compliance plans for the subparts.

As an example, consider a state with two utilities in different balancing authorities, one utility that is part of a multistate RTO and another utility that is not in an RTO and acts as its own balancing authority. Also, assume that the RTO is proposing a regional mass-based compliance plan which the state would like to pursue for that part of the state. As a first step, the state would identify which EGUs are in which subpart of the state and establish emission rate standards for each of the subparts whose weighted average equals the statewide standard. The state then would convert the rate-based standard to a mass-based standard for the RTO part of the state based on the EGUs in that part of the state and the conversion methodology discussed above, including an appropriate provision for load growth. The RTO part of the state would be required to show that actual EGU emissions were less than or equal to the mass-based standard in each year, taking into account any transfers of allowable tons pursuant to the approved regional compliance plan. The non-RTO portion of the state would have a compliance plan for its EGUs to meet the standard for that subpart of the state, using either a rate-based or mass-based approach.

In sum, each of Entergy's four utility states have split operating regimes. It is crucial that these states are provided the flexibility to "split their emissions" among these various structures, as long as they can show that on an integrated basis, they satisfy the state's standard.

For both of these issues (converting to a mass-based approach and splitting the state between balancing authorities), EPA needs to provide clear and definitive guidance on what would be acceptable, so that states are able to reflect that guidance in the submittal of their state plans.

E. Technical and policy errors in the calculation of the proposed standards in the Entergy utility region render the Proposed Rule untenable.

1. Specific Building Block 1 Issues

In setting each state's target goal for CO_2 emissions, EPA uses Building Block 1 to reduce emissions of CO_2 from the 2012 baseline. Building Block 1 assumes an average efficiency increase of 6% for each coal plant by reducing the heat rate (btu/kw) by 6%. EPA bases this assumption on a study conducted by Sargent and Lundy in 2009 to assess available heat rate improvement at coal plants in the United States. EPA further assumes that 2% of the efficiency increase comes from physical changes, such as equipment upgrades, and 4% of the efficiency increase comes from changes in operational practices. These assumptions are flawed.

Where available, many coal units, such as Entergy's Independence Unit 2, already have undertaken efficiency improvements. The turbine for Independence Unit 2 was upgraded prior to the 2012 baseline. Because EPA's proposal uses a certain, single-year baseline, this unit gets no credit for reducing its CO_2 emissions prior to the baseline and is, in fact, penalized, because now the unit must implement additional measures to further reduce CO_2, and these measures likely will have a higher marginal cost than the actions already taken. Similar projects, such as the installation of intelligent soot blowers, the operational improvement of feedwater heaters, the installation of improved fan blades, and the installation of neural networks, frequently took place at coal units across the nation prior to the 2012 baseline.

Not all of the measures identified by the Sargent and Lundy report are available to every coal unit, and the installation of some measures would be mutually exclusive of others for some units. Entergy performed a high-level assessment of the possible efficiency improvements that could be realized at Entergy's coal units from all of the measures outlined in the 2009 Sargent and Lundy report. Some of the improvements are not practical for Entergy units (such as installing variable fan drives for induced draft fans and lowering air heater outlet temperatures). Some would not result in efficiency gains at Entergy units (such as changing the bottom ash sluicing systems). Entergy's assessment determined that if all of the items identified by Sargent and Lundy's report that could be implemented at Entergy coal units were implemented successfully, the average heat rate improvement would be 2% to 4%.

Additionally, EPA included efficiency improvements for R. S. Nelson Units 1A and 2A (Westlake, Louisiana) in setting the state goal for Louisiana in Building Block 1. These units are operated by Entergy, but are owned by Nelson Industrial Steam Company. The units were constructed for the purpose of supplying electrical power and steam to chemical plants and refineries owned by Nelson Industrial Steam Company, and the units do not supply one-third or more of their potential electric output to a utility distribution system on a three-year rolling average basis. These units, therefore, are not "affected units," as defined by the Proposed Rule, and should be removed from the state's calculation.

2. Building Block 2

a) Nameplate Capacity/Net Capacity

A major error occurs in Building Block 2 when EPA uses the nameplate capacity to determine the generating capacity of each NGCC. Nameplate capacity is gross capacity and does not account for generation that is used to power equipment at the plant, such as fan and pump motors. Since in this context the generation from an NGCC is being used to offset net generation from other units (coal, oil/gas steam), only net NGCC capacity should be counted. Net capacity is the capacity available from a generating unit to be supplied to a utility transmission/distribution system. The best source for net capacity is the National Electric Energy Data System (NEEDS), and in fact this is what EPA used when conducting the IPM modeling runs for the Proposed Rule (NEEDS v 5.13). Entergy suggests that EPA use this source for NGCC net capacity information. For Arkansas, Louisiana, Mississippi, and Texas, peak power consumption occurs in the summer months; therefore, net summer capacity from NEEDS v 5.13 should be used in goal setting. Examples of these summer net capacity ratings are shown in Attachment 4.

b) Specific Building Block 2 Issues

There are several errors in EPA's data used in Building Block 2 for Entergy's utility states. Examples follow.[33] Louisiana Station 1 is a co-generation facility that was constructed for the purpose of supplying electricity and steam to the Exxon refinery. The units do not supply

[33] Entergy expects additional Building Block 2 calculation and assessment errors to be detailed in comments submitted by the States of Arkansas, Louisiana, Mississippi, and Texas. For example, Building Block 2 for Louisiana also includes the Washington Parish Energy Center. This unit was once planned, but was never constructed, so it should be removed from the goal-setting calculation for Louisiana.

one-third or more of their potential electric output to a utility distribution system on a three-year rolling average basis, and thus are not defined as "affected units" by the Proposed Rule and should be removed from the state's goal-setting calculation. Additionally, Louisiana Station 1 Units 1A, 2A, and 3A are steam units, not NGCC units.

Perryville Unit 2-CT is listed in the goal-setting calculation as an NGCC unit. This is a low-use simple cycle turbine and should be removed from the state's goal-setting calculation.

Louisiana has two NGCC units under construction that should be included in the goal-setting calculation for the state. Entergy's Ninemile Unit 6 has a nameplate capacity of 640 MWs and a summer net capacity of 550 MWs. Louisiana Energy and Power Authority's unit 14-01 has a nameplate capacity of 84 MWs and a summer net capacity of 64.5 MWs.

In Mississippi, EPA calculation for setting the state goal includes 150 MWs of NGCC under construction. To the best of our knowledge, there is no NGCC under construction in Mississippi.

c) The Uncertain Displacement of Existing Generation by Additional NGCC Generation

As discussed in other comments filed on this topic, there is a fundamental question concerning the ability of existing NGCC to ramp up to a 70% capacity factor to offset existing coal and oil/gas steam generation. Most of the concern centers around the infrastructure needs for this increased capacity, such as transmission and natural gas pipeline infrastructure.

However, in other areas, NGCCs with the technical ability to meet such capacity factors already are being utilized to a high degree. EPA quoted a 2012 average NGCC utilization rate of 35% across the United States in the Proposed Rule. However, the table below showing January through October 2014 capacity factors for Entergy units demonstrates that, for these units, the national average does not apply. The average NGCC capacity factor is 57.7%, and the average coal plant capacity factor is 71.1%.

January – October 2014

Entergy Utility Capacity Factors

Coal Units:	
Nelson Unit 6	59.8
Independence	76.6
White Bluff	76.9
Average Coal	**71.1**
NGCC Units:	
Acadia 2	63.75
Hot Spring	17.9
Hinds	69.7
Attala	73.6
Ouachita	52.8
Perryville	68.4
Average NGCC	**57.7**

Two problems arise in this situation from EPA's reliance on Building Block 2. First, there may be less delta in current and future (up to 70%) capacity factor that should be factored into Building Block 2. Second, if an NGCC unit already is being used at a high-capacity factor, such as for load following or even baseload generation, the unit's flexibility to take on additional generation responsibilities within the system likely is limited.

d) Interstate Disparities

Interstate disparities in goal setting under the Proposed Rule have been exacerbated by EPA's treatment of existing NGCC capacity in Building Block 2. Unlike renewables in Building Block 3, where EPA has taken a semi-regional approach, existing NGCC potential is viewed under a strictly "within the state" approach. The service territories of the Entergy operating companies (utilities) have a higher percentage of existing NGCC capacity (relative to load) than most other regions. Under the Proposed Rule, Entergy's utility states (Arkansas, Louisiana, Mississippi, and Texas) are required to reduce emissions significantly even though its utility fossil average emissions/MWh already is below the standard for new NGCCs. This approach also ignores the fact that Entergy is in an interstate power pool balancing authority, MISO. As noted above, Entergy states' MISO load represents approximately 24% of MISO TWh, but they include approximately 45% of the NGCC redispatch potential within MISO (*see* chart below).

As demonstrated in the table below, allocating this potential more broadly across a larger region would reduce the collective compliance obligation of the Entergy states without weakening the overall standard.

Allocating NGCC redispatch responsibility among MISO states by load ratio share would reduce the collective obligation in MISO South by 19.4 TWH or 47%.

State	Assumed NGCC Redispatch (TWh)			2012 Load in MISO (TWh)	NGCC Redispatch Reallocated to MISO States by Load Ratio Share (TWh)	Delta	
	State Total	State Load in MISO	MISO Share of Redispatch			TWH	%
Arkansas	18.7	66.7%	12.5	31.2	4.5	(8.0)	(64%)
Illinois	13.0	33.9%	4.4	48.7	7.0	2.6	59%
Indiana	4.2	78.0%	3.3	83.2	12.0	8.7	268%
Iowa	6.3	93.0%	5.9	42.5	6.1	0.2	4%
Kentucky	0.8	12.1%	0.1	10.8	1.6	1.5	1427%
Louisiana	20.2	89.6%	18.1	75.9	10.9	(7.2)	(40%)
Michigan	12.3	95.5%	11.7	100.1	14.4	2.7	23%
Minnesota	11.3	96.1%	10.9	65.3	9.4	(1.5)	(13%)
Mississippi	11.9	43.1%	5.1	20.9	3.0	(2.1)	(41%)
Missouri	7.9	50.3%	4.0	41.5	6.0	2.0	50%
Montana	0.0	5.4%	0.0	0.8	0.1	0.1	N/A
North Dakota	0.0	58.6%	0.0	8.7	1.3	1.3	N/A
South Dakota	2.0	26.2%	0.5	3.1	0.4	(0.1)	(14%)
Texas	82.9	6.8%	5.6	24.8	3.6	(2.1)	(37%)
Wisconsin	8.1	99.7%	8.0	68.6	9.9	1.9	23%
ETR States	**133.7**	**30.9%**	**41.4**	**152.8**	**22.0**	**(19.4)**	**(47%)**
MISO Total	**199.6**	**45.2%**	**90.2**	**626.1**	**90.2**	--	--

Sources: EPA Clean Power Plan Goal Development TSD; "MISO ISO Allocation Factors: State Level and MISO Local Resource Zone" using 2012 EIA Form 861 data

3. Building Block 3

a) Realistic Renewable Energy Potential and State Goals

The method used to calculate state-specific renewable energy ("RE") is flawed and unworkable for many of the states in which Entergy operates. Under the proposed method, EPA averages the individual state 2020 Renewable Energy Standard requirements within each of six EPA-determined regions and then sets a regional renewable target for 2029 equal to this average. EPA then calculates a regional annual growth rate for RE generation that is required for the state to reach the regional target. EPA then applies that growth rate to each state's level of 2012 RE generation. EPA's state-specific RE goals assume states start increasing RE generation in 2017 and continue increasing RE generation every year through 2029.

(i) The regions were formed arbitrarily, and EPA did not group states with comparable renewable energy resources.

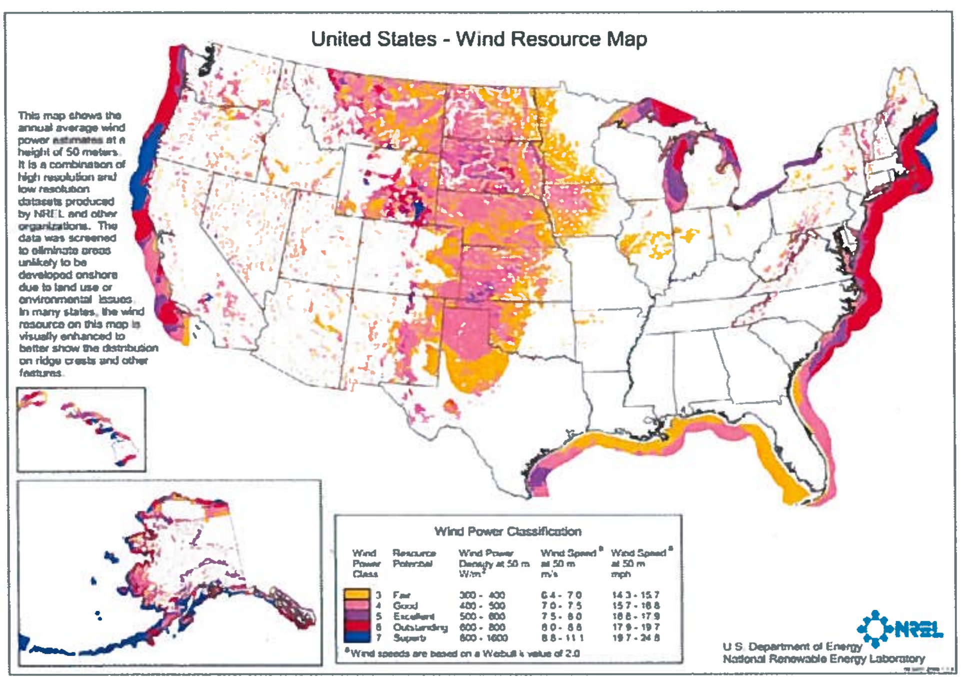
For the purposes of setting the RE goals, Louisiana and Arkansas were grouped within the South Central region, along with Nebraska, Kansas, Oklahoma, and Texas. EPA's regional approach, described above, essentially imposes the same fixed regional target percentage to all states in a given region regardless of the existing mix of RE resources in a state. The South Central regional benchmark growth rate was set by EPA at 8%, using the Kansas renewable portfolio standard ("RPS") established in 2010. It does not appear that EPA considered whether or not a particular state within the region possessed the same renewable resources as the benchmark state, which is a crucial oversimplification.

The U.S. Department of Energy's National Renewable Energy Lab ("NREL") estimates that Kansas ranks number two in the country for wind energy potential based upon potentially developable wind capacity, Texas ranks number one, and Nebraska ranks number four. By comparison, Arkansas ranks 28 and Louisiana ranks 39.[34] The amount of windy land area available for development within a state is vitally important for determining the economic potential for developing wind capacity and generation. Areas with annual average wind speeds around 6.5 meters per second and greater at an 80-meter height and showing capacity factors of 30% or greater are generally considered to be a resource suitable for wind development. Utility-scale, land-based wind turbines typically are installed between 80 and 100 meters high. The table below shows for each of the states in the South Central region the total windy land area with a 30% capacity factor at 80 meters, the percentage of that windy land excluded due to being protected lands (national parks, wilderness, etc.), and the estimated "available" windy land suitable for development. As shown in the table below, Arkansas and Louisiana *combined* have only 1% of the available windy land of the benchmark state Kansas.

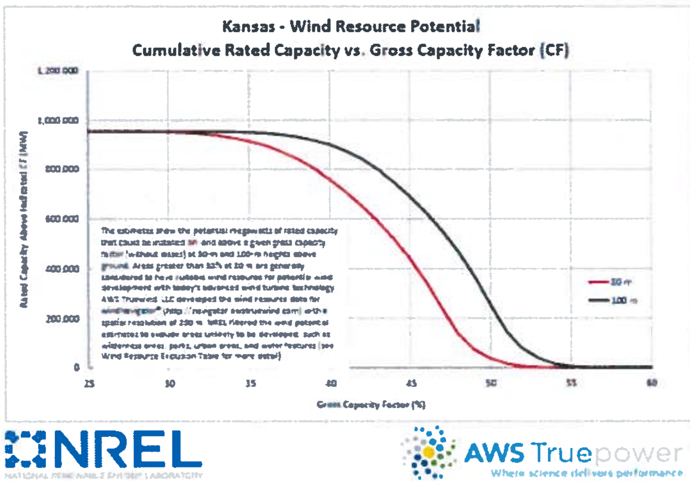
[34] NREL, *Estimates of Windy Land Area and Wind Energy Potential, by State*, (April 2011).

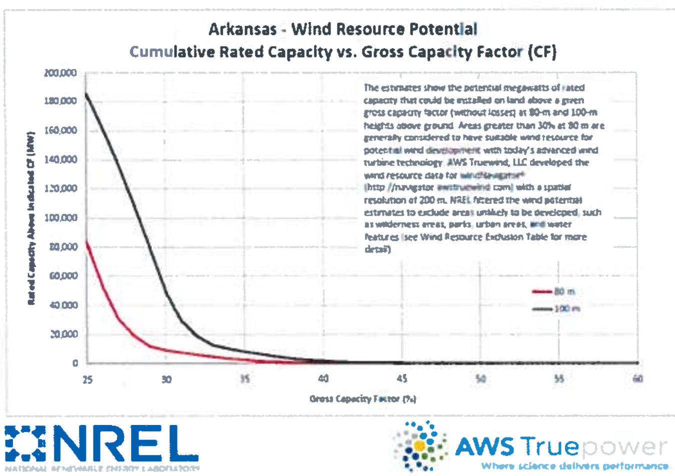
	Total Windy Land Area >30% CF @ 80 m (km_2)	Windy Land Area Excluded (%)	Available Windy Land Area (km^2)
Texas (1)	435,639	12.7%	380,306
Kansas (2)	211,861	10.1%	190,474
Nebraska (4)	199,628	8.0%	183,600
Oklahoma (9)	123,245	16.1%	103,364
Arkansas (28)	4,663	60.5%	1,840
Louisiana (39)	125	34.7%	82.0

The NREL Wind Resource Map below shows dramatically that Louisiana, Arkansas, and even most of Texas have very different wind resources than Kansas, Nebraska, Oklahoma, and northwest Texas.

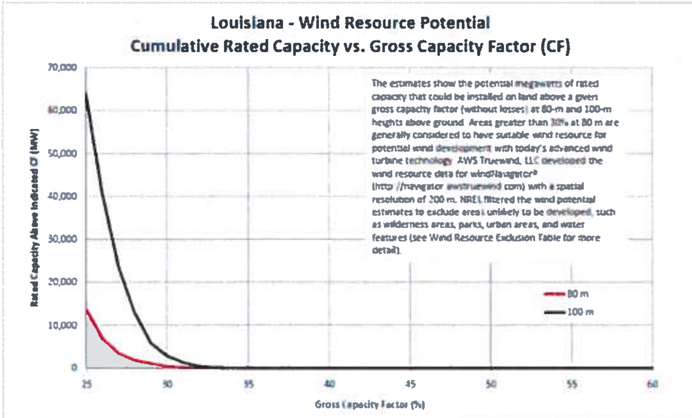


As shown in the charts below, NREL estimates that Kansas has more than 950,000 MW of potential wind resources with ≥ 30% capacity factor. By comparison, Arkansas and Louisiana have 9,000 MW and 410 MW of potential wind resources with ≥ 30% capacity factor, respectively.[35]





[35] Entergy uses this NREL information as a basis of commenting on the Building Block 3 regions, but does not, by doing so, endorse as correct all NREL information presented.



NREL

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The basic problem with placing Louisiana and Arkansas in the same renewable (Building Block 3) region as Kansas is discussed pointedly by NERC in its November 2014 report on the Proposed Rule titled *Potential Reliability Impacts of EPA's Proposed Clean Power Plan* (included as Attachment 5). NERC discusses several problems with the Building Block 3 methodology in general, and in particular states:

> Given the combination of a low population, large land area, and very high wind resource availability, Kansas has relatively low costs to meet its RPS. However, Louisiana (ranked #48 in wind resources and double the retail sales) is assigned the same non-hydro renewable target. To put these two states in the same region sets unattainable targets for Louisiana.

NERC at 12.

The inequity is demonstrated further by a study DOE conducted in 2008 showing projected wind capacity development from a 20% national RPS scenario.[36] The report noted that some states, such as Louisiana and Mississippi, have lower quality wind resources, and that, even under the modeled "20% RPS policy scenario," there would be virtually no wind capacity development in Louisiana by 2030. Yet EPA projects that Louisiana will be able to nearly triple its current non-hydro RE production of roughly 2,430,000 MWh per year to 7,572,000 MWhs by 2030. Realistically, the lack of a wind resource leaves only woody biomass, waste heat recovery, geothermal, off-shore wind, and solar photovoltaic ("PV") as RE alternatives. It

[36] United States Dept. of Energy, *20% Wind Energy by 2030* (July 2008), (http://www.nrel.gov/docs/fy08osti/41869.pdf).

should be noted that virtually all of Louisiana's current RE production is from pulp and paper plant "black liquor" waste that is not scalable like wind.

The tables below show that biomass, waste heat recovery, geothermal, offshore wind, and solar PV all have a higher levelized cost of energy ("LCOE") than the on-shore wind that is so prevalent in the region against which Louisiana and Arkansas were benchmarked (but not in Louisiana and Arkansas).

Louisiana – NREL Renewable Energy Technical Potential & Cost Estimates

	GW[1]	GWh[1]	$/MWh[2]	$/KW[2]
Onshore Wind	<1	935	58	2,094
Bio Power	2	14,873	73	3,500
Hydrothermal	<1	<1	76	5,628
Enhanced Geothermal	61	484,271	92	5,579
Small Hydro	<1	2,423	140	2,971
Off Shore Wind	341	1,200,699	157	5,437
Roof Top Solar PV	12	14,368	161	4,000
Utility Scale Rural PV	2,394	4,114,605	201	3,220
Utility Scale Urban PV	32	55,669	201	3,220
Concentrated Solar PV	0	0	239	9,374
CCGT			40	1,200

1. "U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis", NREL, July, 2012 - Technical potential provides estimates of energy generation potential based on renewable resource availability and quality, technical system performance, topographic limitations, environmental, and land-use constraints only. The estimates do not consider economic or market constraints, and therefore do not represent a level of renewable generation that might actually be deployed. http://www.nrel.gov/docs/fy12osti/51946.pdf
2. NREL Levelized Cost of Energy Calculator http://www.nrel.gov/analysis/tech_lcoe.html

Arkansas – NREL Renewable Energy Technical Potential & Cost Estimates

	GW[1]	GWh[1]	$/MWh[2]	$/KW[2]
Onshore Wind	9	22,892	58	2,094
Bio Power	2	15,444	73	3,500
Hydrothermal	<1	<1	76	5,628
Enhanced Geothermal	80	628,622	92	5,579
Small Hydro	1	6,093	140	2,971
Off Shore Wind	0	0	157	5,437
Roof Top Solar PV	7	8,485	161	4,000
Utility Scale Rural PV	2,747	4,986,389	201	3,220
Utility Scale Urban PV	16	28,961	201	3,220
Concentrated Solar PV	0	0	239	9,374
CCGT			40	1,200

1. "U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis", NREL, July, 2012 - Technical potential provides estimates of energy generation potential based on renewable resource availability and quality, technical system performance, topographic limitations, environmental, and land-use constraints only. The estimates do not consider economic or market constraints, and therefore do not represent a level of renewable generation that might actually be deployed. http://www.nrel.gov/docs/fy12osti/51946.pdf
2. NREL Levelized Cost of Energy Calculator http://www.nrel.gov/analysis/tech_lcoe.html

(ii) EPA applied the Kansas RPS incorrectly.

EPA set the South Central regional growth rate at 8%, using the Kansas RPS established in 2010 as the benchmark. While the RPS requirements of most other states are based on retail electric sales, Kansas' standard is based on generation capacity. EPA mistakenly applied the Kansas RPS requirements as if they were 20% of retail electricity sales instead of 20% of generating capacity.[37] Entergy estimates that this overstates the benchmark growth rate for the region by approximately 9%.

(iii) EPA's alternative approach corrects some of these issues for Entergy utility states.

EPA has asked for comments on an alternative approach to setting renewable energy targets that is based on each state's renewable energy technical potential and realistic development rates and that takes into consideration market and economic factors. The alternate method for Building Block 3 is a two-step process. The method uses each state's "technical potential" for utility scale solar, on-shore wind, geothermal, and hydro renewable, as determined

[37] *See* Kansas Renewable Portfolio Standard, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=KS07R&re=0&ee=0.

by the 2012 NREL study, multiplied by a benchmark development rate percentage equal to the average development rate for each renewable technology in the top one-third performing states. Then, the method conducts an IPM model run to identify how much renewable generation would be built with a defined savings or avoided cost of $30/MWh. The target is then set as the lesser of the two.

EPA's alternate proposed approach addresses some of the key flaws in the proposed approach for Entergy utility states, at least in concept. Entergy supports a state-by-state assessment of RE technical and market potential, but the current alternative proposed by EPA includes problems of its own [*See* CICS comments], such as requiring some states that have already invested heavily in RE to do much more.

4. Building Block 4 – Demand Side Energy Efficiency

The fourth Building Block in the Proposed Rule is energy efficiency/demand side management ("EE/DSM") that is intended to reduce demand for generation by end-users. Conceptually, a reduction in demand would result in a reduction in generation, which in turn would result in a reduction in emissions. EPA estimated energy efficiency in the twelve leading states to achieve annual incremental electricity savings of at least 1.5% per year. EPA's concept of BSER assumes that many states increase their current annual savings rate by 0.2% starting in 2017 and continuing until reaching a maximum rate of 1.5%, which then continues through 2030. "States already at or above the 1.5% annual incremental savings rate. . .realize a 1.5% rate in 2017 and maintain that rate through 2029." 79 Fed. Reg. 34872-73.

After explaining that EPA's estimates of potential energy efficiency savings are "potentially overstated" for several reasons, NERC adds that EPA's theory that even these overly optimistic predictions will counteract normal load growth is counter to the predictions of other electric system experts. NERC states:

> With potentially overstated expectations for energy efficiency savings, the EPA's demand forecast results in a decline in electricity use between 2020 and 2030. While other major power market forecasters' electricity sales compounded annual growth rates (CAGRs) for the period between 2020 and 2030 are strictly positive (AEO 2013: 0.7 percent, EPRI: (achievable potential) 0.4 percent, NERC average of assessment studies: 1.5 percent), the EPA assumes a CAGR of -0.2 percent for the same time period. Between 2020 and 2030, the EPA assumes incremental year-over year reductions from energy efficiency to be almost 41 TWh nationally on average, outpacing year-over-year national electricity sales growth of 31.6 TWh, on average. The main reason for this result is the EPA's

assumption of states being able to sustain an annual incremental growth rate in energy efficiency savings of 1.5 percent once achieved. As mentioned above, this sustainability is not supported by any peer-reviewed or technical studies of energy efficiency potential.

NERC at 15 (Attachment 5, below).

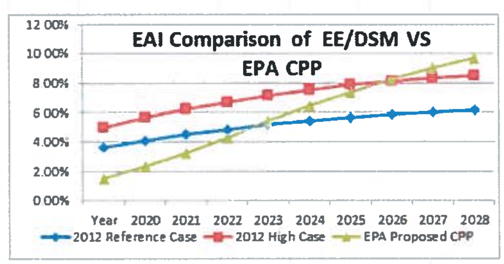
Entergy's utility companies operate reflecting varying levels of implementation of energy efficiency programs within their respective jurisdictions. Entergy Texas began implementation in 2000; Entergy Arkansas in 2007; Entergy New Orleans in 2011; and Entergy Mississippi has begun its implementation in 2014. Entergy Louisiana and Entergy Gulf States Louisiana are awaiting an implementation order. These programs are specific to and dependent upon the approval of the state utility regulators.

EPA estimated potential EE/DSM outcomes by state. Below is a comparison of the estimated potential EE/DSM available as included in the Integrated Resource Plans ("IRP") for each of the Entergy utility companies. When one considers the internal estimates prepared for inclusion in the IRP cases, it is clear that EPA's estimates for EE/DSM are overly optimistic. This is especially apparent for the Arkansas and Texas utility companies, which have the most experience with the EE/DSM efforts. With the exception of Entergy Mississippi, EPA estimates exceed the reference cases included in the IRPs. For the two Entergy companies that have the most robust history (Entergy Arkansas and Entergy Texas), EPA's estimates exceed the IRP high cases. For the Entergy Louisiana companies (Entergy Gulf States Louisiana, Entergy Louisiana, and Entergy New Orleans), EPA's terminal values are higher than the reference case, but lower than the expected high cases.

EAI

Year	2012 Reference Case	2012 High Case	EPA Proposed CPP
2020	3.62%	4.98%	1.52%
2021	4.08%	5.63%	2.31%
2022	4.50%	6.22%	3.24%
2023	4.86%	6.72%	4.28%
2024	5.17%	7.16%	5.42%
2025	5.44%	7.54%	6.46%
2026	5.69%	7.89%	7.41%
2027	5.87%	8.16%	8.26%
2028	6.02%	8.37%	9.03%
2029	6.15%	8.54%	9.71%

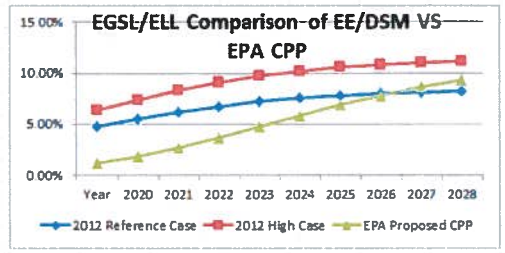
*Based on 2012 EAI IRP



EGSL & ELL

Year	2012 Reference Case	2012 High Case	EPA Proposed CPP
2020	4.76%	6.40%	1.14%
2021	5.46%	7.36%	1.85%
2022	6.14%	8.28%	2.71%
2023	6.72%	9.08%	3.69%
2024	7.19%	9.73%	4.78%
2025	7.55%	10.22%	5.88%
2026	7.80%	10.57%	6.88%
2027	7.98%	10.82%	7.78%
2028	8.12%	11.02%	8.60%
2029	8.23%	11.18%	9.33%

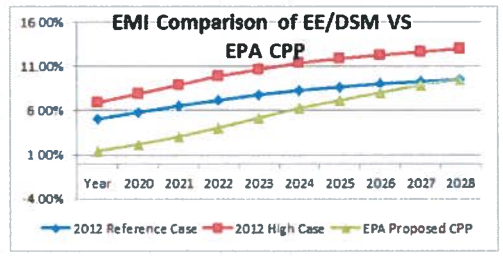
*Based on 2012 System IRP



EMI

Year	2012 Reference Case	2012 High Case	EPA Proposed CPP
2020	5.10%	6.91%	1.40%
2021	5.85%	7.94%	2.17%
2022	6.57%	8.94%	3.07%
2023	7.24%	9.88%	4.09%
2024	7.81%	10.68%	5.22%
2025	8.30%	11.36%	6.28%
2026	8.71%	11.91%	7.24%
2027	9.04%	12.35%	8.11%
2028	9.32%	12.71%	8.89%
2029	9.57%	13.02%	9.59%

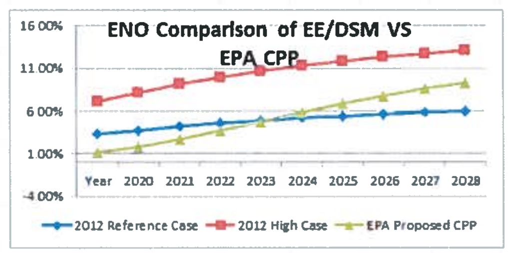
*Based on 2013 EMI IRP



ENO

Year	2012 Reference Case	2012 High Case	EPA Proposed CPP
2020	3.29%	7.20%	1.14%
2021	3.74%	8.19%	1.85%
2022	4.18%	9.12%	2.71%
2023	4.56%	9.94%	3.69%
2024	4.89%	10.66%	4.78%
2025	5.17%	11.28%	5.88%
2026	5.41%	11.83%	6.88%
2027	5.63%	12.32%	7.78%
2028	5.82%	12.75%	8.60%
2029	6.01%	13.16%	9.33%

*Based on 2012 ENO IRP

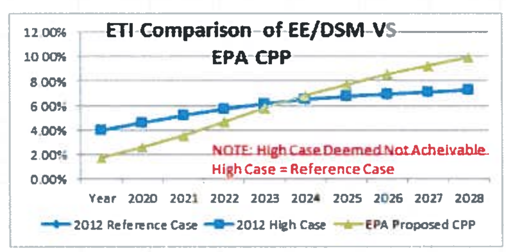


ETI

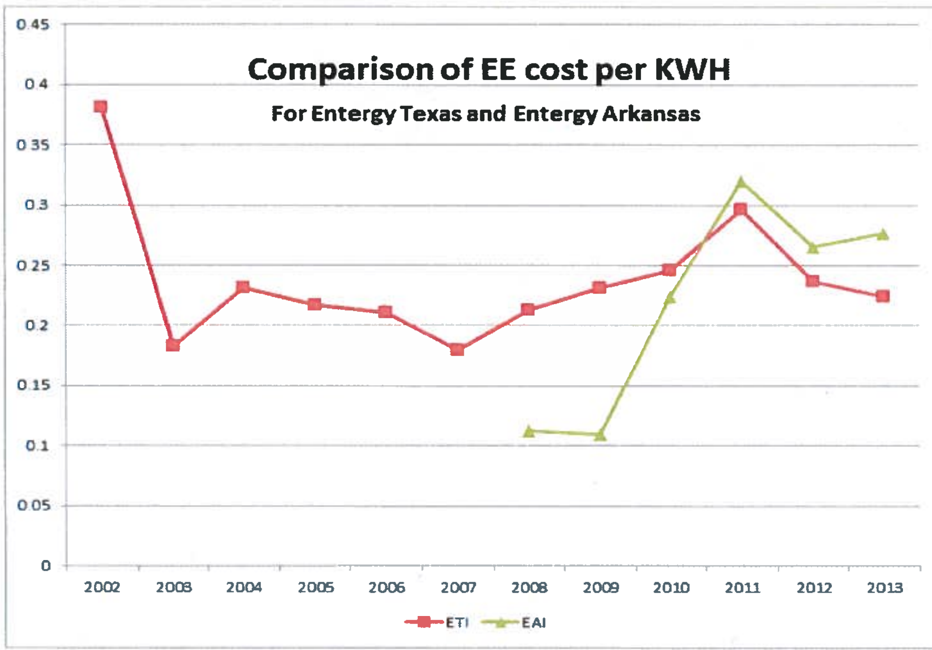
*High Case Results Deemed Not Acheivable - -High Case = Ref. Case Here

Year	2012 Reference Case	2012 High Case	EPA Proposed CPP
2020	4.02%	4.02%	1.78%
2021	4.63%	4.63%	2.62%
2022	5.18%	5.18%	3.59%
2023	5.68%	5.68%	4.68%
2024	6.11%	6.11%	5.78%
2025	6.46%	6.46%	6.79%
2026	6.73%	6.73%	7.70%
2027	6.93%	6.93%	8.52%
2028	7.09%	7.09%	9.26%
2029	7.23%	7.23%	9.91%

*Based on 2012 System IRP



While EPA's estimates may be achievable theoretically, the cost for this level of EE/DSM would be prohibitive. The experience garnered from Texas and Arkansas indicates that the most cost-effective "low hanging fruit" of efficiency measures already has been harvested. Additional EE/DSM "harvests" are expected to come at a much higher cost. For each additional KWh saved, the costs per KWh for these savings are increasing. Included below is a graphic that shows the experience from Entergy Arkansas and Entergy Texas, demonstrating how the cost of EE/DSM has escalated over time. The Entergy utility companies in Louisiana and Mississippi have had only limited experience with the programs to date and, therefore, do not have sufficient history for comparison.



Entergy's primary concern regarding the Building Block 4 implementation (as opposed to goal-setting, discussed above) is the ambiguity of regulatory authority. The primary responsibility for implementation of and compliance with the 111(d) plan for a state falls to the environmental regulatory bodies, such as, in Entergy's utility states, the Arkansas Department of Environmental Quality, the Louisiana Department of Environmental Quality, the Mississippi Department of Environmental Quality, and the Texas Commission on Environmental Quality. Each of these environmental regulatory agencies has authority only for "inside the fence" environmental operations and lacks the authority for the "outside the fence" obligations of Building Block 4 (EE/DSM).

In contrast, the authority for establishing and providing recovery mechanisms for traditional utility costs, as well as the costs associated with Building Block 4 and the other proposed Building Blocks, belongs to the utility regulatory commissions (e.g., the Arkansas Public Service Commission, the Louisiana Public Service Commission, the Mississippi Public Service Commission, the New Orleans City Council Utility Committee, and the Public Utility Commission of Texas).

The ambiguity of responsibilities among the various agencies will be difficult to manage. The "beyond the fence" regulation has the potential to require generators to answer to two (or more) masters. The utility regulatory bodies will be responsible for the cost recovery and goal setting and administration, while compliance with the statewide emissions rate falls to the environmental regulatory bodies. Of course, this concern applies not only to Building Block 4, but to the entire proposed regulatory scheme.

Ultimately, the responsibility for developing and implementing the 111(d) state plan will need to align with the program design, implementation, and cost recovery responsibility of the utility regulators for EE/DSM programs. The success or failure of the SIPs that implement Building Block 4 must be measured consistently. Lack of a consistent tool and assumptions will be problematic. Evaluation, measurement, and verification ("EMV") of EE/DSM is an important component of the effectiveness of Building Block 4. EPA should work with the states to develop a consistent tool to estimate the success or failure of the program, using the cost and benefit impacts for energy efficiency on the statewide emission rate as one of the metrics. Otherwise, there is the potential for estimates to be a patchwork of methodologies, assumptions, and outcomes that cannot be compared easily between and among states. Participants (generators, regulators, customers, and others) must have a useful metric to measure the success of the programs.

In addition, the impacts to the generators and utilities will be difficult to discern in regions where there is not a match of service boundaries to political boundaries (i.e., state borders). The regulators likely will require a common approach with which all participants comply to allow for the summation of the results for the entire state.

VII. Additional Technical and Miscellaneous Comments

A. Use of a Single vs. Multiple Source Categories and Sub-categorization

EPA proposes emission guidelines for the two existing categories of existing affected EGUs (Da and KKKK) and solicits comment on combining them into a single category (UUUU) (which would contain all the proposed requirements for GHG from existing affected EGUs). EPA solicits comment on this proposal and on whether combining the two categories would offer additional flexibility, for example, by facilitating implementation of CO_2 mitigation measures, such as shifting generation from higher to lower-carbon intensity generation among existing sources (e.g., shifting from boilers to NGCC units) or emissions trading among sources. 79 Fed. Reg. 34855. Entergy supports the creation of a voluntary combined source category structure that is available for affected entities participating in an emissions market, as this would facilitate flexibility in compliance, including regional approaches and trading.

B. Comments on Specific Proposed Rule Language

1. 60.5770

Section 60.5770(a)(3) is confusing and unclear as to what is required in a state plan that converts from a rate-based standard to a mass-based standard. The subsection appears to require that the conversion impose the entirety of state emission reductions on affected EGUs, although the goal would have been developed through the application of all four Building Blocks. The conversion is required to represent emissions from affected EGUs as if "the affected EGUs were to perform at an average lb CO_2/MWh rate equal to the rate-based goal for the state," in other words, after the application of all four Building Blocks. Reading from (a) of the subsection, this appears to be the identification of the "mass-based goal, [solely reflected] in tons of CO_2 emitted by affected EGUs over the plan performance period." How this "beyond the fence" Building Block calculation would be included in emission limits imposed, through air permits, on the "inside the fence" operations of an affected unit is quite unclear.

Section 60.5740(a)(3), concerning the required elements of a state plan, requires the "identification of the state *emissions performance level* from *affected entities*." The definitions of "emissions performance level" and of "affected entities" given in 60.5820 indicate that this performance level does not apply only to EGUs, but to any entity "with obligations under this subpart for the purpose of meeting the emissions performance goal requirements." Section

60.5740(a)(3)(ii) also indicates that emission performance levels are for "affected entities," and refers back to the possibility of a conversion to mass under 60.5770. Section 60.5740(3)(ii)(B) then states that a mass-based conversion is to "represent the total tons of CO_2 that will be emitted by affected entities," not solely as reflected by affected EGUs, in contradiction to 60.5770.

If the language of 60.5770 is intended to create an enforceable emission rate for affected units that implements the reductions from all four Building Blocks, then the section is unrealistic, arbitrary and capricious, and would create a strong disincentive for conversion to a mass-based standard. At best, it is extremely unclear.

2. 60.5795

Subsection 60.5795(b)(2), concerning which EGUs must be addressed in a state plan, includes only a subset of stationary combustion turbines. The subsection includes only combustion turbines of a certain size, that supply a certain amount of electricity to a utility distribution system, and that "combust[s] over 90% natural gas on a heat input basis on a 3-year rolling average basis." This provision would exclude from consideration in state plans combustion turbines that use oil as fuel more than 10% of the time. This distinction is contrary to the discussion of the definition of "affected units" in the preamble, 79 Fed. Reg. 34854, where EPA describes the unit combustion type, size, and generation for distribution percentage elements of the definition but does not mention an exemption for oil-fired units. If combustion turbines are included in the final rule as affected sources (*see* CICS comments regarding additional comments on why combustion turbines should be excluded from the final rule), then combustion turbines that fire oil should be included just as those that fire natural gas are included, especially since emission rates for oil-fired units are likely to be higher than those for gas-fired units. EPA states no basis for the disparate treatment of oil-fired and gas-fired combustion turbines.

C. EPA's Recent NODA Regarding Additional Rulemaking Options

On October 30, 2014, EPA published a NODA related to the Proposed Rule. The NODA identifies several additional issues on which EPA solicits comments regarding its process for setting state-specific CO_2 emission rate goals utilizing the four Building Blocks created in the proposed CPP Rule. One of the areas on which EPA seeks comment is how Building Blocks 3 and 4 are treated in setting the state emission goals.

As stated above, Building Block 3 involves EPA's treatment and assumptions regarding RE and nuclear energy generation. In particular, EPA projects that states can achieve a certain level of RE over the 2020-2030 time frame. In the Proposed Rule, electricity generated by RE is added to a state's baseline (2012) generation level. This number is then divided into the state's GHG emissions to produce an emission rate goal, expressed in lbs CO_2/MWh. As more RE generation is added to the generation (denominator), with no change to the emissions (numerator), the effect is to make the emission rate goal more stringent. Under Building Block 4, EE is treated similarly. As energy efficiency measures are installed, EPA projects that the measures reduce electric consumption by some amount. That reduced consumption (MWh) similarly is added to the denominator, making the emission rate goal more stringent.

EPA notes that it had received comment from some stakeholders suggesting that EPA should adjust the numerator and denominator downward based on the assumption that the proposed RE and EE activities will result in a decrease in generation and emissions from existing fossil units. EPA also seeks comment on whether EPA should (1) presume that coal-fired generation is displaced first, or (2) use an average emission level based on all fossil generation. The effect of either would be to make both interim and final state emission rate goals substantially more stringent.

Entergy objects to this approach. The approach simply is not based in reality, over-estimates the effect of EE and RE on emissions, and completely ignores load growth on electric systems. First, EPA has set unrealistic RE goals for the Entergy system, which is a separate but very important problem discussed above. EPA projects an RE growth rate for Mississippi, Louisiana, and Arkansas based on a regional average that ignores the lack of RE potential in these states. Second, in the Proposed Rule, EPA incorrectly has stated that it expects there to be no increase in electric demand as a result of the EE programs that EPA effectively is mandating. As outlined above, Entergy has been implementing EE programs in some of its states for many years and, contrary to EPA's assumption, load and electric demand continue to increase. Assuming that the EE programs will reduce existing fossil generation is simply wrong. At most, EE will slow the growth in electricity demand over the next decades. As for RE, EPA's projections of RE potential in Entergy's states are dramatically overstated. Entergy's utility states simply do not have such RE potential. Thus, for EPA to presume that hypothetical (but unattainable) RE generation will reduce existing fossil generation would be arbitrary and capricious.

Finally, EPA seeks comment on whether it should presume that emissions from coal-fired generation should be preferentially used when adjusting the numerator or whether some weighted average of all fossil emissions should be used. As discussed above, EPA should do neither. However, if EPA elects to adjust the numerator, EPA must recognize that electric systems (whether a utility, ISO, or other balancing authority) will reduce generation from the highest variable cost units first and not, as EPA suggests, based on the fact that "because fossil steam generation has higher carbon intensity, it should be replaced before NGCC generation." 79 Fed. Reg. at 64553. Thus, as RE comes online, the units that will be backed off generally will be legacy oil and gas steam units, peaking combustion turbine units, NGCCs, and then baseload coal units. In some cases, where few peaking and NGCC units are available, load-following coal units may be used to reduce generation.

VIII. Conclusion

For the reasons stated above, Entergy urges EPA to withdraw the current Proposed Rule and to reissue the rule, if at all, with modifications addressing the issues and concerns raised by these comments.

Respectfully submitted,

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