IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA,
STATE OF TEXAS, *et al.*

Petitioners,
v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, and
REGINA MCCARTHY, Administrator,
United States Environmental Protection Agency,

Respondents.

Case No. 15-1363

On Petition for Review of a Final Action of the
United States Environmental Protection Agency

STATE PETITIONERS' MOTION FOR STAY
AND FOR EXPEDITED CONSIDERATION
ADDENDUM
PART II of II

CONTENTS

Exhibit B

- In announcing the final Clean Power Plan, President Obama will mark another major milestone for his presidency and cement his record in terms of taking historic action on climate change.

- There are few issues that are more important to the President, who sees acting on climate as a moral, economic and national security obligation. That's why he continues to demonstrate true leadership on this issue, in the domestic and international arenas.

- The Clean Power Plan and other policy initiatives, including landmark greenhouse gas emission standards for cars, trucks and heavy-duty vehicles, have established the United States as an international leader on climate as we head toward efforts to secure an ambitious and lasting agreement in Paris. And as we have seen, the Clean Power Plan is changing the international dynamic and leveraging international action – showing that when the U.S. leads, other nations follow.

The Rule

- The final EPA rule to be released on Monday will be more ambitious than the proposed rule by reducing power-sector carbon pollution 32 percent from 2005 levels in 2030, a 9 percent increase over the proposal.

- The final rule will also drive a more aggressive transition to zero-carbon renewable energy sources than the proposed rule. The share of renewable energy generation capacity in 2030 is projected to be over 25 percent higherthan in the proposed rule, at 28 percent, compared to 22 percent.

  - The proposed rule relied on a large, early shift of coal generation to natural gas. For example, the share of natural gas in the generation mix was projected to be significantly higher in 2020 than in the baseline.

  - In the final rule, that early rush to gas is eliminated. Indeed, the share of natural gas is essentially flat compared to business as usual.

  - Instead, the rule drives early reductions from renewable energy and energy efficiency, which will drive a more aggressive transformation in the domestic energy industry.

- An important driver of these outcomes is the Clean Energy Incentive Program, which that will incentivize early deployment of renewable energy and energy efficiency.

  - Under the program, credits for electricity generated from renewables in 2020 and 2021 will be awarded to projects that begin construction after participating state plans are submitted.

  - The program also prioritizes early investment in energy efficiency projects in low-income communities; these projects will be awarded double the number of credits in 2020 and 2021 as compared to qualifying renewable energy projects.

  - Taken together, these incentives will cut energy bills for low-income families, drive faster renewable energy deployment, further reduce technology costs, and lay the foundation for deep long-term cuts in carbon pollution. In addition, the Clean Energy Incentive Plan provide additional flexibility for states, and will lower the overall cost of the Clean Power Plan.

- The final rule keeps the U.S. on track for the goals President Obama has made.

  - In 2020, with full utilization of the incentive program, we would reduce emissions from the power sector at least 27% below 2005 levels by 2020, consistent with the reductions achieved in the proposed rule. Reductions in 2025 are also consistent with the proposed rule.

  - By achieving a more ambitious emissions reduction target in 2030, the rule will drive deeper decarbonization after 2030 than in the proposed rule.

- The final rule will lead to significant savings for consumers and public health benefits across the population. Specifically the final rule will:

  - Save the average American family about $85 annually on their energy bill by 2030. Additionally, costs are projected to decline earlier in the decade than in the proposed rule due to accelerated deployment of renewable energy and efficiency measures.

  - Due to the Clean Power Plan and other policies to increase clean energy, the total burden on public health due to power plant emissions will decline dramatically, including an 88% decline in premature death.

- The final rule also sets standards in a way that better reflects the way the electricity grid operates, resulting in a more level playing field for power sector emissions reductions nationwide.

Administration Push

- The release of the Clean Power Plan is the starting gun for an all-out climate push by the President and his Cabinet.

- In the next several weeks, the President will speak frankly and frequently about how climate change is already harming American lives and livelihoods—and what we can do to address it.

    - He will address the National Clean Energy Summit in Nevada where he will discuss steps the private and public sectors can take to accelerate deployment of renewable energy.
    - He will be the first President to travel to the Alaskan Arctic.
    - He will discuss climate change with Pope Francis on his visit to the US.

- In addition, members of the Cabinet, including Secretaries Foxx, Jewell and Moniz and Administrators McCarthy and Contreras-Sweet, will also spend time during Congress' August recess delivering this clear and direct message in districts throughout the country. The Vice President will also engage on the issues of climate during the recess. Other Cabinet agencies, including Labor, State, HHS, HUD, and Treasury, will reinforce these messages with targeted constituencies through op-eds and social media channels.

Exhibit C

IN THE
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DECLARATION OF KEITH BAUGUES,
ASSISTANT COMMISSIONER, INDIANA DEPARTMENT OF ENVIRONEMNTAL MANAGMEMENT

I, Keith Baugues, declare as follows:

1. I am the Assistant Commissioner of the Office of Air Quality (OAQ) for the Indiana Department of Environmental Management (IDEM). I have been the Assistant Commissioner of OAQ for over five (5) years. I have forty-two (42) years of experience working on air pollution issues, including six (6) years with the Indiana Air Pollution Control Division, nine (9) years with the U.S. Environmental Protection Agency, eight (8) years with the Office of Air Quality Planning and Standards and twenty two (22) years as environmental consultant in Illinois, Texas, Colorado and Indiana. As the Assistant Commissioner of OAQ, I have personal knowledge and experience to understand what steps IDEM has taken and will need to undertake in response to the Environmental Protection Agency's *Carbon Pollution Emission*

Guidelines for Existing Stationary Sources: Electric Utility Generating Units, published on the EPA website on August 3, 2015 (Section 111(d) Rule). EPA-HQ-OAR-2013-0602, available at http://www.epa.gov/airquality/cpp/cpp-final-rule.pdf. The final Section 111(d) Rule sets a deadline of September 6, 2016 for submitting initial plans, with the final deadline for a complete plan, with all legislative authority required to implement the plan, in place by September 6, 2018.

2. I submit this declaration for the purpose of describing the efforts of the State of Indiana to prepare to implement the Section 111(d) Rule since the Declaration of IDEM Commissioner Thomas Easterly was submitted in this case.

3. To date, we have taken the following steps:

a. We have held two (2) stakeholder meetings to update stakeholders regarding the Section 111(d) Rule and gain their input.

b. We have formed a working group consisting of representatives of IDEM, the Governor's Office, the Indiana Office of Energy Development, the Indiana Utility Regulatory Committee, and the Indiana Office of the Utility Consumer Counselor. The purpose of these meetings has been to prepare for the new costs, plans, rules and legislation that are likely to be needed as the result of the Section 111(d) Rule, if it passes judicial muster. We have had three (3) meetings so far.

c. We are preparing modeling analyses to be done by the Indiana State Utility Forecasting Group. The purpose of this work is to determine the potential effects of various strategies that might meet the Section 111(d) Rule, such as increased utility rates, lost jobs, closure of utilities and the cost of new infrastructure.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Executed on this 13th day of October in Indianapolis, Indiana.

Keith Baugues

Keith Baugues
Assistant Commissioner
Office of Air Quality
Indiana Department of Environmental Management

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DECLARATION OF DAVID L. BRACHT, DIRECTOR,
NEBRASKA ENERGY OFFICE

I, David L. Bracht, declare as follows:

1. I am the Director of the Nebraska Energy Office ("NEO"). I have been employed at the NEO since January 2015. I have over 30 years of business, government and legal experience, including as a senior executive in private industry and government agencies and, for the last 10 years, as a private practice attorney working in the energy industry. As part of my duties, I have authority to monitor, track, and interact with stakeholders and regulators on the development

and implementation of state and federal environmental rules impacting public utilities.

2. I have personal knowledge to understand what steps Nebraska has taken and will likely need to take in response to the EPA's Section 111(d) Rule, including future resource planning for system reliability. In general, the Section 111(d) Rule will dramatically transform the way electric power will be generated and transmitted to consumers in Nebraska and throughout the United States. The Rule will, at the very least, require the construction of new power generation and transmission facilities and associated infrastructure, the updating or decommissioning of existing power generation and transmission facilities that are not fully depreciated, and changes to the electric power system that will affect the availability, cost and reliability of electric power for every single current and future consumer. In short, the Section 111(d) Rule will transform the American energy economy.

3. Based on my work experience and position, I have determined that implementing the Section 111(d) Rule will be a complicated, time consuming, and expensive endeavor, which will require the expenditure of substantial State resources, immediately and over the next calendar year.

4. Significant NEO resources have already been invested to understand and evaluate the proposed 111(d) Rule. NEO employees have spent approximately

375 hours understanding the rule and preparing for implementation, including outreach to Nebraska stakeholders, organizing stakeholder meetings and listening sessions, participating in regional collaboratives such as the National Association of State Energy Officials and the Midwest Energy Efficiency Association with other states and industry participants, and in-depth analysis of the impact of the Section 111(d) Rule on the state and regional systems.

5. NEO employees and consultants will be required to spend additional time and resources modeling the changes made from the proposed to the final Section 111(d) rule. The purpose of this model will be to forecast the cost of the changes in the Nebraska utility market that are necessary to comply with the Section 111(d) Rule, and the resulting impact on electric rates and overall economic growth.

6. Based on my knowledge and experience, the Section 111(d) Rule represents an unprecedented infringement by the EPA on the traditional authority of Nebraska to manage energy resources within our jurisdiction because the mandates of the Section 111(d) require NEO to undertake specific changes to how energy is provided to consumers. The Section 111(d) Rule also disrupts the well-settled division of authority over electricity markets under the Federal Power Act, and raises significant uncertainty about the role of the Federal Energy Regulatory Commission to ensure the reliability of electricity through the wholesale market.

7. Because compliance planning must begin immediately, it is important that this Court grant the States' Petition for Review. The system-wide changes necessary for compliance must be gradual to preserve reliability of the electric grid. Because compliance is calculated based on a rolling average, the longer Nebraska waits to begin compliance, the more expensive and difficult it will be to meet the requirements of the Rule.

8. Similarly, evaluation of specific compliance measures, such as new facilities or retirements, must also begin immediately. The lengthy application and approval process for utilities to construct, upgrade, or retire facilities to comply with the Section 111(d) Rule, as well as the in-depth evaluation of public necessity and convenience for each facility, requires utilities to plan and submit applications for upgrades almost immediately after publication of the final Section 111(d) Rule in order to have equipment constructed, upgraded, or decommissioned before the compliance period begins in 2022.

9. The NEO will need to spend approximately 850 hours over the next calendar year as a direct result of the Rule. The expenditure of these resources must begin immediately. This process includes the development of studies required by state statute to evaluate and estimate the impact on rates and reliability, and the resulting impact on economic development caused by potential retirements and replacements of generation and transmission facilities.

10. The Section 111(d) Rule will also severely threaten reliability and increase the cost of electricity by forcing Nebraska to move immediately toward reliance on a limited number of fuel sources. The risks associated with this type of system-wide transformation will occur in the next year, unless the Rule is stayed. The threats posed by this shift in resources and transformation of Nebraska's existing power system are particularly significant in the more sparsely populated rural areas of Nebraska that have limited transmission capabilities. The rural areas will also face a significant economic burden due to more limited tax base and the distributed nature of Nebraska's public power system. Nebraska's relatively small total population will also limit the resources available for implementing this significant change, thereby increasing the impact on ratepayers resulting in a negative impact on the entire state economy.

11. Changes made for the sake of compliance with the Section 111(d) Rule immediately and over the next calendar year will be irreversible and will impact the electric grid for decades. System planning is typically based on the 30-40 year lives of generation and transmission facilities. Building, redesigning, and adjusting power generation facilities takes years, and decisions made in these areas are often irreversible once they are made. For example, the decision to prematurely retire an electric generating unit could have significant consequences for system reliability and may unnecessarily increase costs to ratepayers for

decades to come. This is particularly true because of Nebraska's relatively small total population and the significant areas of the state that are sparsely populated.

12. The implementation of the Section 111(d) Rule will require legislative and constitutional changes on the state level that may permanently alter the daily operation of utilities. In order to meet the significant reductions under the Section 111(d) Rule, Nebraska will likely be forced to implement control measures outside of the physical location and control of electric generating units, such as end-use energy efficiency (reduced energy use by electricity consumers), demand response (usage changes according to instantaneous market and load-profile changes), and increased distributed generation (such as small residential renewable installations). While such "outside" control measures are not expressly required under the Section 111(d) Rule, they appear unavoidable and will require Nebraska to immediately set in motion the chain of events, including statutory changes, larger investment in customer-side behavior, and further rate restructuring, in order for these compliance options to contribute to the Section 111(d) Rule's emission reduction targets.

13. Nebraska is the only state in which 100% of electric power is provided by municipalities, public power districts and electric cooperatives. The 167 independent public power entities in Nebraska have separate boards of directors, in most cases elected by the local ratepayers. Imposing the top-down control will disrupt and undermine Nebraska's commitment to local public control that has

proven valuable over its 80 year history. Undertaking these measures will seriously disrupt the State's sovereign priorities, which would otherwise be devoted to addressing other pressing issues of public concern.

14. If Nebraska chooses to adopt a multi- state approach to complying with the Section 111(d) Rule, changes to rights and responsibilities of entities such as Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs") will be immediately and long lasting. If Nebraska joins in a multi-state compliance approach, it is likely to take the form of credit trading or an induced carbon price through the RTO. The members of these organizations must follow a prescribed stakeholder process to effect the changes, and Nebraska must agree to grant certain enforcement powers to those organizations. The stakeholder process and any necessary institutional changes for these organizations will likely need to be completed before a plan relying on those third parties can be submitted for approval to the EPA. These processes are lengthy, difficult to reverse once established, and will require immediate expenditure of resources over next calendar year.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Executed on October 14, 2015.

David L. Bracht

David L. Bracht
Director, Nebraska Energy Office

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DECLARATION OF WEST VIRGINIA,
DEPARTMENT OF ENVIRONMENTAL PROTECTION

I, William F. Durham, declare as follows:

1. I am the Director of the Division of Air Quality at the West Virginia Department of Environmental Protection (DEP). I have been employed at the DEP for over 23 years. For the most recent 10 years, I have been responsible, in a supervisory capacity, for the development of state plans and revisions thereto submitted to the U.S. Environmental Protection Agency (EPA) pursuant to the Clean Air Act (CAA) as amended. 42 U.S.C.A §§ 7401 - 7671q. These include

revisions to the State Implementation Plan (SIP) pursuant to CAA §110 and plans, or revisions to plans, pursuant to CAA §111. During my tenure, I have overseen the development of a multitude of state plans which were submitted to EPA for approval, including every SIP revision or state plan West Virginia has produced in the last ten years. Some of the more substantial plans include five (5) EPA-approved ozone maintenance plans for areas previously designated as nonattainment under the ozone National Ambient Air Quality Standard (NAAQS); six (6) EPA-Approved fine particulate maintenance plans under the $PM_{2.5}$ NAAQS; a partially approved Regional Haze plan (the deficiency was outside of the state's control); and a fully approved Regional Haze Five-Year Progress Report SIP. Moreover, under my supervision, nine (9) West Virginia Legislative Rules were developed, adopted by the state and approved by EPA for incorporation into the West Virginia SIP. Finally, I supervised the development of four (4) attainment demonstrations for previous fine particulate nonattainment areas, which included highly technical photochemical atmospheric modeling.

2. With my personal knowledge and experience, I understand the steps that DEP has taken and those it will need to undertake in response to the EPA's Section 111(d) Rule. Based on my experience, I have determined that implementing the Section 111(d) Rule will be an extremely complicated and time-consuming endeavor. It will be the most complicated CAA implementation effort

West Virginia has ever undertaken. The Section 111(d) Rule is unlike any other Clean Air Act implementation undertaken by West Virginia. Specifically, the Section 111(d) Rule's reliance on measures outside the affected facilities' boundaries (fence-line)—building blocks 2, and 3—are entirely unprecedented for any state. West Virginia will be required to expend an unprecedented amount of resources to design a State Plan that incorporates emission rate and/or emissions mass reductions related to these building blocks. It is also apparent that other state entities beyond DEP, including, but not necessarily limited to the West Virginia Division of Energy and Public Service Commission will expend significant resources as well. Because of the unprecedented reach of the 111(d) Rule into areas that neither the CAA nor its state law counterpart in West Virginia have ever been extended, authorizing legislation presenting many issues at the highest level of state policy will require the state Senate, the state House of Delegates and the office of the West Virginia Governor to expend significant resources in developing, and guiding the policy for implementation of the 111(d) Rule.

3. Since the rule was proposed in June of 2014, at least five (5) DEP senior staff employees have expended 2,700 hours or more on understanding the Section 111(d) Rule and preparing for its implementation, including: reading the proposed rules and supporting documentation; drafting comments on the proposal; holding meetings with power plant owners/operators, the Division of Energy, the

Public Service Commission, and PJM, the Regional Transmission Organization that serves West Virginia; and, participating in numerous webinars and conference calls in an effort to understand the options available to the state in order to comply with the rule as proposed.

4. Several constraints combine to force the DEP to put a great deal of its resources into the work of developing a state plan immediately. As suggested above, adoption of legislation authorizing the DEP to expand the scope of its regulatory jurisdiction will be required. After that is accomplished, compliance with legislative rulemaking requirements for adoption of implementing regulations requires nearly a year, beginning in May and extending through legislative approval of rules in March of the following year. Drafting the necessary legislation and rules will be a time consuming endeavor. The State Plan DEP must develop is subject to Legislative approval and the constraints contained in the West Virginia Code. Furthermore, EPA's deadlines in the 111(d) Rule make it nearly impossible for DEP to design a State Plan in time to comply.

5. The stringency of the 111(d) Rule's interim goals exacerbates the pressure on the DEP to immediately dedicate a great deal of resources into development of a State Plan. To comply with the interim goals that purportedly provide a "glidepath" from 2022 to the final goals in 2030, affected power producers must begin their efforts well before the interim goals take effect in 2022.

Any delay in expending resources to develop and submit a state plan to EPA will shorten the amount of time power producers will have to begin their compliance efforts, making them less likely to be able to comply. After a Plan is submitted to EPA, whatever additional time is lost in EPA's approval process will further shorten the time power producers have to try to comply with the interim requirements and make them even less likely to be able to comply with them. Days lost in DEP's development and submission of a State Plan and in EPA's approval of it are days the power industry will not have to devote to compliance efforts.

6. Planning and compliance for the Section 111(d) Rule, including designing a State Plan, will require an unprecedented amount of resources, the expenditure of which has already begun. The Section 111(d) Rule gives West Virginia until September 6, 2016 to submit its initial State Plan. Extensions are available for up to two years for submittal of a final plan. In practice, a state has only one year to make the critical decisions that will dramatically affect its citizens and economy for decades to come, requiring careful consideration of all available approaches. EPA has illustrated at least six basic approaches that a state may adopt. Submission of a plan will require the state to consider these and other approaches and choose an approach within little more than a year, so that a timely plan submittal can be made. In addition to describing the approach the initial plan must also: identify

how it applies to affected EGUs; demonstrate that the plan will meet the applicable rate or mass state goal; define monitoring, reporting and recordkeeping requirements for affected EGUs; specify state recordkeeping and reporting requirements; document public participation and public hearing and include any pertinent documentation. Preparing and submitting a timely plan requires several dedicated DEP staff members, as well as significant resources from other state agencies, stakeholders, and the legislature. Activities include: reviewing the final rule to determine whether the data and underlying assumptions used in calculating the goal are correct; educating the regulated entities and other stakeholders regarding provisions of the final rule; coordinating with the PSC and DOE regarding renewable energy standards, demand side management programs and other issues; evaluating different compliance strategies that could be implemented to meet the interim and final goals; determining the statutory and regulatory changes needed for each of the strategies; and taking initial steps to develop support across all stakeholders and policy makers for potential compliance strategies. Concurrently, the DEP will need to review and comment on EPA's proposed "backstop" Federal Plan (FP) to evaluate the consequences if the state is unable to submit an approvable plan in a timely manner. I estimate that DEP will need to engage nine (9) senior staff employees, providing 7,100 hours of effort or more to address these tasks.

7. EPA has recently issued two "SIP Calls" to West Virginia to correct deficiencies in the extant SIP: *Findings of Failure To Submit a Section 110 State Implementation Plan for Interstate Transport for the 2008 National Ambient Air Quality Standards for Ozone* and *State Implementation Plans: Response to Petition for Rulemaking*, 80 Fed.Reg. 39961 (July 13, 2015), and *State Implementation Plans: Response to Petition for Rulemaking; Restatement and Update of EPA's SSM Policy Applicable to SIPs; Findings of Substantial Inadequacy; and SIP Calls To Amend Provisions Applying to Excess Emissions During Periods of Startup, Shutdown and Malfunction; Final Rule*, 80 Fed.Reg. 33840 (June 12, 2015). Moreover the state has outstanding obligations to address two nonattainment areas under the sulfur dioxide standard. The enormous resource drain caused by attempting to understand the requirements of a final rule and develop an approvable 111d plan will severely impact the DEP's ability to fulfill these and other obligations under the CAA.

8. Implementation of the Section 111(d) Rule will require statutory and regulatory changes, all requiring considerable staff time. The Section 111(d) Rule requires a sweeping change to the DEP's authority. In addition to submitting a compliance plan for EPA approval, DEP must have the ability to enforce each portion of the state plan, many elements of which are beyond DEP's current authority. In order to have the ability to enforce components of the plan, such as

energy efficiency and redispatch of electricity on the grid, the West Virginia legislature will have to re-write state law. Consultation to ensure that authorities are clearly delineated among agencies will include additional meetings with PSC and DOE staff, owners/operators of power production and PJM.

9. Importantly, the required changes in West Virginia's law will need to be undone if the Section 111(d) Rule is invalidated.

10. The aforementioned reasons demonstrate that a stay of the final Section 111(d) rule is clearly warranted.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct. Executed on this 10th of August 2015, at Charleston, West Virginia.

William F. Durham

WILLIAM F. DURHAM

OFFICIAL SEAL
NOTARY PUBLIC
STATE OF WEST VIRGINIA
TAMRA L. MOWRER
WV DIVISION OF AIR QUALITY
601 57th STREET, SE
CHARLESTON, WV 25304
My commission expires January 2, 2016

Tamra L. Mowrer

C000019

IN THE UNITED STATES COURT OF APPEALS
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STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ________

DECLARATION OF THOMAS W. EASTERLY, COMMISSIONER, INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

I, Thomas W. Easterly, declare as follows:

1. I am the Commissioner of the Indiana Department of Environmental Management (IDEM). I have been the Commissioner of IDEM for over ten years. As the Commissioner, I have personal knowledge and experience to understand what steps IDEM has taken and will need to undertake in response to the Environmental Protection Agency's *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, published on the EPA website on August 3, 2015 (Section 111(d) Rule). EPA-HQ-OAR-2013-0602, available at http://www.epa.gov/airquality/cpp/cpp-final-rule.pdf. The final Section 111(d) Rule sets a deadline of September 6, 2016 for submitting initial plans, with

the final deadline for a complete plan, with all legislative authority required to implement the plan, in place by September 6, 2018.

2. IDEM has determined that implementing the Section 111(d) Rule will be a complex and time-consuming endeavor. Specifically, creating a plan under the Section 111(d) Rule is complicated by the Rule's unprecedented reliance on outside-the-fence control measures, including increased utilization of renewable energy. IDEM has determined it cannot meet the reduction goals set by the Section 111(d) Rule solely through the implementation of heat rate improvements, and thus will be forced to implement unorthodox outside-the-fence control measures in order to have its plan approved. Such measures will require a coordination effort across multiple state agencies, including the Indiana Utility Regulatory Commission (IURC) and the Indiana Utility Forecasting Group (IUFG). Currently, neither IDEM nor any other Indiana state agency has the authority to implement outside-the-fence controls in the measurable and enforceable fashion required by the Clean Air Act. Therefore, in order to comply with the Rule, the State would have to take legislative action to ensure the appropriate state agencies have the authority needed to create and implement any state plan.

3. Indiana's power supply is also governed by more than one Regional Transmission Organization (RTO), requiring coordination with both the Midcontinent Independent System Operator (MISO) and the Pennsylvania Jersey

Maryland Power Pool (PJM), in attempting to find ways to implement the outside-the-fence building block. The coordination among state agencies and RTOs, as well as the legislative changes required to implement the Rule, make creating a state plan extremely difficult, especially in the limited timeframe contemplated by the Section 111(d) Rule.

4. As a practical matter, in light of the September 6, 2016 and September 6, 2018 deadlines, the State cannot wait until the litigation challenging the Rule is concluded to begin evaluating the Section 111(d) Rule and expending substantial resources to create a state plan. The State has already expended resources and expects to take further steps in the coming years as a direct result of the Section 111(d) Rule. This expenditure of resources will likely include coordinating among state agencies and RTOs, seeking input of interested stakeholders, participating in external modeling and cost analyses, and possibly requesting legislative changes to give IDEM or another state agency the authority needed to implement the outside-the-fence building block required by the Rule. Without a stay of the final rule, IDEM cannot wait until litigation is concluded before expending significant time and resources on formulating a state plan and seeking regulatory and legislative authority to implement the plan. However, even if Indiana begins its work immediately, it is unlikely that it can meet the timeframes for reductions set by the Section 111(d) Rule. The deadline for Indiana state agencies to propose legislative

changes to be considered during the 2016 Indiana Legislative Session has passed, so any legislative changes made in response to the 111(d) Rule will not take effect until at least July of 2017. Indiana's statutory rulemaking process then takes at least eighteen months to complete, meaning Indiana will likely not have an approvable plan in place prior to the final September 6, 2018 deadline. From a resource perspective, the Section 111(d) Rule also detracts from efforts to implement other requirements of the Clean Air Act, and provides no additional revenue or resources to the State.

5. Significant changes have been made in the final Section 111(d) Rule from the version that EPA published for public comment on June 18, 2014. 79 Fed. Reg. 34,830. These changes have negated much of the work IDEM has already performed in trying to formulate a plan based on the draft language, and will now require significant analytical work to formulate an approvable plan in the short timeframe set by the September 6, 2016 deadline. Specifically, the final rule includes a substantial increase in the reductions required by Indiana sources. For example, the proposed rule set a emissions rate of 1,531 CO_2 lbs/Net MWh to be achieved by 2030, while the final rule sets a 2030 rate of 1,242 CO_2 lbs/Net MWh. IDEM has already spent time and resources trying to formulate a plan that would achieve the reductions in the proposed rule; Indiana must now perform new calculations and analysis, and has barely a year to perform this work.

6. Another change in the final Section 111(d) Rule is the option to implement an emissions trading program as part of a state plan. Inclusion of a trading program would require significant coordination with other states to ensure enough credits are available for exchange through approved trade-ready plans. Again, this coordination will be difficult, if not impossible, to perform before the September 6, 2016 deadline. Additionally, on the same day that it published the Section 111(d) Rule on its website, EPA issued a proposed rule, *Federal Plan Requirements for Greenhouse Gas Emissions form Electric Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulation.* EPA-HQ-OAR-2015-0119, available at http://www.epa.gov/airquality/cpp/cpp-proposed-federal-plan.pdf. *Inter alia,* the draft rule purports to offer implementation guidance on trade-ready programs. However, the proposed rule is not final yet, and therefore Indiana and other states cannot rely on its guidance in attempting to develop an approvable state plan that includes emissions trading. It is possible the rule providing guidance on trading programs will not be finalized until after the Section 111(d) Rule's September 6, 2016 deadline for submitting plan proposals, further supporting the need for a stay of the Rule's deadlines.

7. The proposed rule mentioned above also includes a draft federal plan for states that are not able, or choose not to, have a state plan approved by EPA. As stated earlier, the draft rule may not be finalized before the September 6, 2016 deadline for submitting plan proposals. Without a stay of the submittal deadlines in the Section 111(d) Rule, Indiana and other states will be forced to make decisions about whether to attempt to formulate a state plan, or choose to be subject to a federal plan, with incomplete information on what the federal plan would entail.

8. In addition, it is uncertain whether any state plan will be approved by EPA in time for utilities to comply with the Section 111(d) Rule's interim goals. As stated above, the reductions required of Indiana sources in the final rule are significantly greater than the proposed rule, largely because the reliance on zero-emitting renewables increased by threefold. The reductions in the final rule are based on a regional flat rate of 20.5% zero-emitting renewables (RE), or more than 22 million MWh. While the final rule does not mandate that RE be utilized to achieve the required reductions, it is highly unlikely that Indiana will be able to develop an approvable plan that does not rely on a considerable growth in zero-emitting renewable energy. Based on the complexities, required coordination and consultation, it would take Indiana all if not more of the three full years to devise a plan, and, based on my experience as Commissioner, EPA is likely to take at least 2 years to act on it. Therefore, at best, an enforceable plan would not be in place

until mid-2020. Utilities, the state utility regulatory agencies, and the RTOs would likely not take action on measures within a state plan until it is federally approved and enforceable. In order for Indiana and its EGU fleet to comply with the rule's 2022 interim goal, all measures would need to be in place by January 1, 2022. Once the state plan is approved, the utilities would have less than two years to secure utility commission approval of cost for infrastructure improvements necessary to achieve the goal and institute the changes needed. For renewables, time is required to secure capital equipment financing, add the infrastructure necessary to get the energy from the equipment to the grid, acquire property and transmission line right-of-way, and finally construct the equipment and required transmission. For both fossil fuel and renewable projects in Indiana over the course of the past 10 years, a minimum of 5-10 years has been required from utility commission approval to when energy is delivered to the grid. Achievement of the Section 111(d) Rule's interim goals is therefore practically infeasible.

9. Undertaking the required measures will seriously disrupt the State's sovereign priorities, which would otherwise be devoted to addressing other pressing issues of public concern. Importantly, the above-described measures would also involve changes in Indiana regulations and statutes, which will then need to be undone if the Section 111(d) Rule is invalidated. Again, this would seriously disrupt the State's ability to achieve its own sovereign priorities.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct. Executed on this 12TH day of August in Indianapolis, Indiana.

Thomas W. Easterly, Commissioner
Indiana Department of Environmental Management

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ________

DECLARATION OF RONALD W. GORE

I, Ronald W. Gore, hereby declare as follows:

1. I am the Chief of the Air Division within the Alabama Department of Environmental Management (ADEM). I have been employed by ADEM for 41 years. As part of my duties, I am responsible for the Division's development of State plans to implement federal air quality rules and regulations.

2. Based on my position, I have the personal knowledge and experience to understand what steps the State will need to undertake in response to EPA's finalized *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, 79

Fed. Reg. 34,830 (June 18, 2014) ("Section 111(d) Rule" or "Rule"). This includes personal knowledge and experience in preparing a State plan consistent with the Rule. Under that Rule, the State must submit a plan to the Environmental Protection Agency ("EPA") by late summer of 2016, absent special circumstances.

3. Based on my knowledge and experience, I believe that developing Alabama's response to the Section 111(d) Rule will be the most complex air pollution rulemaking undertaken by ADEM in the last 41 years. I have been responsible for and worked on many State plans designed to be submitted to and approved by EPA, including plans for attaining air quality standards, construction and operating permit plans, visibility rules, etc. The Clean Air Act recognizes the time and resources necessary to draft and finalize such plans by providing three to five years, at a minimum, for States to submit them. In the 111(d) Rule, EPA requires that States submit a vastly more complex rule in one to three years.

4. EPA has proposed that GHG reductions can be maximized by viewing the electric utility system in a very broad way, i.e., that States can and should regulate facilities and consumer behavior in ways never before considered to be authorized by the CAA. This broadening of authority means that ADEM will likely have to seek authorization from the State Legislature to implement EPA's proposal. It is likely that other Alabama agencies will need to participate in enforcing parts of Alabama's plan and broad new State Legislative authority will be needed for them as well. ADEM historically has been the agency solely responsible for air quality compliance in the State. Having several other State agencies closely involved in the development and administration of air quality rules presents a daunting challenge for ADEM.

5. Since EPA proposed the Section 111(d) Rule in June of 2014, ADEM has expended considerable resources in attempting to understand the State's necessary response. Two employees have been assigned full-time to analyzing the proposal. I estimate that in addition to the two full time employees mentioned above, an additional three man years[1] of effort are being expended by fifteen other employees who devote part of their work time on 111(d) issues. In total, I estimate that five man-years of effort, (equating to approximately $475,000 in additional personnel costs per year) are being deployed at present responding to the Section 111(d) Rule. Efforts on which resources have been spent include, but are not limited to, the following examples:

- Checking EPA's calculations and assumptions on the emissions reduction goals the State should attain
- Generating possible responses to check whether they are achievable in practice
- Meeting with trade groups, EPA, other states, environmental groups, individual utilities, etc. to consider their input and viewpoints
- Traveling to and speaking at EPA's Regional Public Hearing
- Traveling to and participating in several national workshops on Section 111(d)
- Holding many internal meetings to facilitate information flow up and down the management chain

6. Now that the Section 111(d) Rule has been finalized and adopted, additional man-years of effort will be needed for ADEM to prepare and submit a plan. Assuming ADEM chooses to prepare and submit a plan, my best estimate is that eight man-years of effort (equating to $760,000 per year for several years) would be needed.

[1] The approximate dollar value of a "man year" is estimated to be $95,000, counting salary, fringe benefits, and overhead.

7. Should the Court rule that EPA has overstepped its authority, ADEM's efforts would cease.

I declare under penalty of perjury that the foregoing is correct.

Executed on this 6th day of August 2015, in Montgomery, Alabama.

Ronald W. Gore

Ronald W. Gore

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos.

DECLARATION OF THOMAS GROSS

I, Thomas Gross, hereby declare as follows:

1. I am the Chief of the Monitoring and Planning Section in the Kansas Department of Health and Environment Bureau of Air Quality. I have been employed by the Kansas Department of Health and Environment for 39 years. As part of my duties, I am responsible for managing the group that develops state plans to implement federal air quality rules and regulations.

2. Based on my position, I have the personal knowledge and experience to understand what steps the State will need to undertake in response to EPA's Section 111(d) Rule, including the preparation of a state plan consistent with the Rule.

3. Based on my work, I have deteiiiiined that implementing the Section 111(d) Rule presents a complicated endeavor, including the creation of the state plan. Based on my experience in working in other state plans and state implementation plans (SIPs) such as

mercury, regional haze, ozone and lead, the Section 111(d) plan will likely take from three to five years, with the longer time frame being required if a multi-state plan is prepared.

4. Creating a plan of the type envisioned under Section 111(d) is a complicated endeavor for several reasons. First is the large potential for stranded investments in the State of Kansas. Kansas is in a unique situation due to the proportion of coal-fired units subject to the BART requirements of the regional haze program. The six largest coal-fired units in Kansas made significant investments in criteria pollutant emission reduction equipment in the last three to four years to comply with EPA's regional haze program. More than $3 billion has been earmarked for these projects that have recently been completed. The financing for these improvements to control criteria pollutants will not mature by the time the Clean Power Plan interim deadlines will require closure of some of these plants to meet the state goal. These plants are operating at control efficiencies that are very near to new BACT rates for new facilities. Although not new, the investments made in pollution control equipment are significant and should be allowed to be amortized over a greater time period than allowed under the Rule.

5. The Rule uses three building blocks to develop the CO_2 emissions goals for each state. Building block number one, regarding heat rate improvements, sets a goal that is not achievable across the entire fleet of affected units in Kansas. A major impediment to the type of boiler upgrade projects that could achieve significant heat rate improvements is the fact that they would likely trigger a Best Available Control Technology (BACT) review as part of a Prevention of Significant Deterioration (PSD) permit process. If a plant were not yet equipped with a SCR unit to control NO_x, a heat rate improvement project that might cost $5 million could turn into an SCR project for NO_x reductions with a price tag of $100 million as a result of a BACT review conducted as part of a PSD permit review process. Smaller scale heat rate improvement projects

that would not trigger a BACT review will not be able to achieve the 4.3% goal contained in this building block.

The third building block requires affected units to achieve CO_2 emissions reductions off the footprint of the affected unit. In Kansas, this building block has the greatest potential for CO_2 emission reductions. Building block number three sets a goal for renewable energy generation based on the potential for wind development in Kansas. There are a limited number of viable sites for wind energy development in Kansas. The number is limited by (1) the listing of the lesser prairie chicken as a threatened species under the Endangered Species act; (2) state policy of protection of Flint Hills ecosystem; and (3) lack of adequate transmission lines or transmission bottlenecks. Kansas utilities will have to compete with neighboring states contracting with merchant wind developers for these limited sites.

Additionally, the renewable energy statutory mandate was changed to a goal during the 2015 legislative session. While Kansas utilities currently meet the requirements of the revoked standard and were on a path to meet the 2020 goal, the shortfalls in meeting the goals established in building block one would have to be made up in building block three. There is a large potential for wind energy development in western Kansas when upgraded transmission lines to out-of-state markets are completed. However, the final Rule does not grant any emission reduction credits to Kansas utilities for the zero emissions wind energy produced in Kansas that is sold out-of-state. In the Rule the renewable energy credits follow the electricity to the out-of-state utility with the power purchase agreement.

To capture credit for the renewable energy sold to out-of-state markets, Kansas will have to participate in some form of interstate program that would include states receiving Kansas wind energy. Such a program would require new statutory authority, significant groundwork in determining which states would participate, resources to develop interstate agreements to create the entity that would administer the trading program, and time to create parallel regulations in each state to implement a program that would allow for Kansas to receive benefit from the zero carbon emissions associated with future wind energy development.

6. While the deadline in the final rule for submission of a final state plan has been extended, the timeframe allowed is still substantially shorter than the time period required to develop the state regional haze plans for EPA's Regional Haze Rule. Therefore, the State could not wait until the Rule was finalized to begin evaluating the Section 111(d) Rule and has therefore expended substantial resources to create a State 111(d) Plan. This expenditure of resources has included significant staff time to date and has expanded significantly as we are moving forward in reviewing the final rule to determine its implications for Kansas. Our activities include evaluating the data and underlying assumptions used in calculating the goal to ensure they are correct; educating the regulated entities and other stakeholders regarding provisions of the final Rule; coordinating with the Kansas Corporation Commission ("KCC") regarding modeling alternate dispatch scenarios to comply with the Rule; evaluating the change in Kansas law regarding implementing renewable energy standards and its impact on complying with the Rule; evaluating different compliance strategies that could be implemented to meet the goal in the final Rule; determining what statutory and regulatory changes will be needed for each of the strategies; and taking initial steps to develop support across all stakeholders and policy makers for potential compliance strategies. With the limitations described above regarding building block number one, implementation of a plan with sufficient renewable energy to meet the goal and offset the harm associated with stranded investments will require significant policy shifts by the Kansas legislature and other policymakers.

7. The State will expend significant resources as a direct result of the Section 111(d) Rule. This includes time to read, absorb, and interpret the several thousand pages of white papers, program design documents, preamble, rule and technical support documents, as well as to attend meetings and conference calls with stakeholders, elected officials and the KCC. The State expects to take further steps in the coming months as a direct result of the Section 111(d) Rule. Kansas will likely need statutory and regulatory changes, all requiring considerable staff time. Consultation meetings will include additional meetings with the KCC staff, the Southwest Power Pool, the Kansas Municipal Utilities, and the Kansas Power Pool. KDHE staff will present legislative briefings once the Kansas Legislature is in session. A considerable amount of staff effort will be needed to educate stakeholders and develop a plan. KDHE expects to spend the equivalent of at least four full-time employee positions per year amongst the six to eight staff and managers who are involved in implementing the final Rule (including proposing a state plan) for the next several years.

8. If a stay is entered by this Court, Kansas will halt the above-described expenditures.

9. Absent a stay from this Court, it is not practical for Kansas to wait to continue work on its State 111(d) Plan. It is already doubtful that Kansas can design a Plan in time to comply with EPA's deadlines. Waiting until litigation concludes will make compliance with EPA's deadlines impossible. And any delay in designing a State Plan will risk Kansas's ability to comply with EPA's deadlines. The timeframes available to states are insufficient to allow compliance with the Rule.

10. Absent a stay from this Court, if Kansas chooses to adopt a multi-state approach to complying with the Section 111(d) Rule, Kansas may need to enter into either a memorandum

of understanding or agreement with the other states. Kansas has limited experience in pursuing this type of agreement with other states, and anticipates that a significant amount of time would be required to negotiate and reach consensus on the content of such an agreement with other state agencies.

11. Absent a stay from this Court, implementation of the Section 111(d) Rule will require legislative changes, which will require the substantial expenditure of State resources that must be spent in the next year, and consideration of which must begin immediately. Undertaking these measures will seriously disrupt the State's sovereign priorities, which would otherwise be devoted to addressing other pressing issues of public concern.

12. Since the finalization of the Section 111(d) Rule, my staff and I have spent hundreds of hours on the following: reading the rule, discussing the rule with EPA in various conference calls; discussing the rule with KDHE management; discussing with and explaining the rule to stakeholders, including Kansas' electric generators; going before a joint committee of the Kansas Legislature in an all-day session to provide agency comment and receive feedback; and more. This has diverted my and my staff's attention away from other matters that we would normally be addressing.

I declare under penalty of perjury that the foregoing is correct. Executed on this _______ day of October 14, 2015, at Topeka, Kansas.

Thomas Gross

Thomas Gross

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF TEXAS, et al Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, and REGINA MCCARTHY, Administrator, United States Environmental Protection Agency, Respondents	CASE no. ___________________

DECLARATION OF SOUTH DAKOTA
DEPARTMENT OF ENVIRONMENT AND NATURAL RESOURCES

I, Brian Gustafson, declare as follows:

1. I am the Engineering Manager III for the Air Quality Program at the South Dakota Department of Environment and Natural Resources ("SD DENR"). I have been employed at this position for nearly 15 years. As part of my duties, I am responsible for the development, administration and enforcement of South Dakota's Air Quality Program. I have personal knowledge and experience to

understand what steps that South Dakota has taken and will need to undertake in response to the United States' Environmental Protection Agency ("EPA") final Section 111(d) Clean Power Plan Rule, hereinafter, referred to as Section 111(d) Rule.

2. South Dakota is a rural state covering approximately 77,000 square miles which is in attainment with all of the federal National Ambient Air Quality Standards. I oversee 14 individuals in the implementation of South Dakota's Air Quality Program with the goal of maintaining our attainment status.

3. South Dakota has received delegation or approval of the following federal air programs from the EPA: South Dakota's State Implementation Plan (minor air quality construction permit program, minor air quality operating permit program, Prevention of Significant Deterioration preconstruction permit program, New Source Review preconstruction permit program, Rapid City area fugitive sanding and construction activity program, ambient air monitoring network, and regional haze program), New Source Performance Standards, National Emission Standards for Hazardous Air Pollutants, Title V air quality operating permit program, and the Acid Rain program.

4. I have been involved in the revision and/or development of these delegated or approved regulatory programs, including the development of

necessary legislation, drafting and presentation of rules, and administration and enforcement of the programs.

5. I have also been involved in the development and implementation of South Dakota's 111(d) State Plan for existing Municipal Solid Waste Landfills.

6. Based on my experience, I have determined that implementing the Section 111(d) Rule will be a complicated and time-consuming endeavor. The Section 111(d) Rule is unlike any other Clean Air Act implementation undertaken by South Dakota. Specifically, the Section 111(d) Rule's reliance on the reduction of demand from a particular source of energy—Building Blocks 2 and 3—in determining Best System of Emission Reductions for Electric Generating Units is entirely unprecedented and will require the use of these outside the fence line measures to comply with South Dakota's final goal. Since EPA established the Best System of Emission Reductions on outside the fence line measures and not demonstrated air pollution control technology available to the utilities, South Dakota will be required to expend an unprecedentedly large number of resources to design a State Plan that incorporates these building blocks and still provide affordable and reliable electricity to South Dakota's constituents.

7. Already, two employees have expended hundreds of hours to understand and comment on the proposed Section 111(d) Rule and met with multi

state organizations on multiple occasions to determine the best way(s) to comply with the proposed Section 111(d) Rule. This does not include the amount of time employees of South Dakota's Public Utilities Commission and other state agencies have spent reviewing and commenting on the proposed 111(d) Rule or the amount of time the electrical industry and the public spent reviewing and commenting on the proposed 111(d) Rule.

8. In EPA's final Section 111(d) Rule, EPA specifies that each state must adequately demonstrate it has sufficient funding to implement the 111(d) State Plan. EPA did not provide any additional funding to support a 111(d) State Plan. South Dakota will have to reprioritize its limited financial resources in order to develop and implement the 111(d) State Plan.

9. In EPA's final Section 111(d) Rule, EPA revamped how each state's goal was calculated and the methods in which to comply with the final state goal. Because the final Section 111(d) Rule has drastically changed from the proposal, I estimate it will take a minimum of two employees in the Air Quality Program hundreds of hours to review and understand EPA's final Section 111(d) Rule.

10. In addition, a minimum of two employees in the Air Quality Program will each expend approximately half their time preparing enough of a 111(d) State Plan to qualify for EPA's two year extension by the September 2016 deadline. A

minimum of two employees will each expend approximately half their time preparing the final 111(d) State Plan by the September 2018 deadline.

11. Based on the complexity of the Section 111(d) Rule, the involvement of South Dakota's Public Utilities Commission and other state agencies, the potential enactment of new state legislation necessary to implement the 111(d) State Plan, and development of new administrative rules necessary for an approvable 111(d) State Plan, SD DENR will need EPA's 2 year extension to complete the 111(d) State Plan.

12. Using essentially one full time employee out of 15 employees within South Dakota's Air Quality Program and using limited financial resources to develop the 111(d) State Plan will hamper South Dakota's ability to conduct its other duties. This does not include the amount of time employees of the South Dakota's Public Utilities Commission and other state agencies will spend on ensuring the 111(d) State Plan provides affordable and reliable electricity to South Dakotan's or the amount of time the electrical industry, the public, and environmental groups will spend in working with SD DENR on the development of the 111(d) State Plan.

13. Absent a stay from this Court, planning and compliance for the Section 111(d) Rule, including designing a 111(d) State Plan, will require an

unprecedented amount of SD DENR's resources, which expenditure will begin immediately. In addition, waiting until the litigation concludes will make compliance with EPA's deadlines impractical. Any delay in designing a 111(d) State Plan will risk South Dakota's ability to comply with EPA's deadlines.

14. If South Dakota chooses to adopt a multi-state approach to comply with the Section 111(d) Rule, South Dakota may need to enter into either a memorandum of understanding or agreement with the other states. South Dakota has limited experience in pursuing this type of agreement with other states, and anticipates that a significant amount of time and financial resources would be required to negotiate and reach consensus on the content of such an agreement with other state agencies.

15. Depending on the complexity of the 111(d) State Plan, implementation of the Section 111(d) Rule may require legislative changes, which will require the substantial expenditure of South Dakota resources that must be spent in the next three years, and consideration of which must begin immediately. In order to submit an EPA approvable 111(d) State Plan, SD DENR must have the ability to enforce each portion of the 111(d) State Plan, some of which SD DENR does not currently have the authority to enforce. In order to have the ability to enforce in-state components of the plan, such as renewable portfolio standards,

energy efficiency, etc., the South Dakota legislature will have to re-write state law to provide the SD DENR that authority.

16. The Section 111(d) Rule establishes the Best System of Emission Reduction for Electric Generating Units on three "Building Blocks", which will require South Dakota to use at least those three building blocks to meet the state's goal. Of these three "Building Blocks", only one is directly in the regulatory control of SD DENR's Air Quality Program: Block 1, Efficiency Improvements at Affected Coal-Fired Steam Electric Generating Units. The Air Quality Program has direct regulatory control over such emissions through its Air Quality Permitting programs.

17. Building Block 2 involves the shifting of energy produced from coal-fired power plants to natural gas-fired combined cycle power plants. South Dakota has one coal-fired power plant and one natural gas-fired power plant. These two power plants are not owned by the same entities, do not have common regional transmission operators, and do not have common customer bases. As a result, this alteration may result in some customers of the coal-fired power plant being without a power source. It is my understanding that the state (including the South Dakota Public Utilities Commission) does not have regulatory authority to order a coal-fired power plant to cut its production; or to order the natural-gas fired power plant

to increase its production rate. As a result, utilization of Building Block 2 may not be an option which will require SD DENR to develop other alternatives to achieve EPA's goal for South Dakota some of which may require new state legislation.

18. Building Block 3 requires the shifting of energy from fossil-fuel fired plants to renewable energy sources; in 2012, South Dakota's wind energy was 24% of its power generation and none of this renewable energy is recognized by the final Section 111(d) Rule. South Dakota must determine how to further encourage private businesses to develop wind resources in an area that has already been developed. This may require new state legislation.

19. These changes required in the final Section 111(d) Rule involve the very fundamentals of power supply and development within the State and concern matters that have traditionally been determined not by state government, but by the marketplace. Thus, much of requirements required in the 111(d) State Plan involve major fundamental changes and will potentially be a matter of significant debate before the South Dakota Legislature.

20. Undertaking these measures will seriously disrupt the State's sovereign priorities, which would otherwise be devoted to addressing other pressing issues of public concern. Importantly, the above-described measures may also involve changes in South Dakota's law, which will then need to be undone if

the Section 111(d) Rule is invalidated. Again, this would seriously disrupt the State's ability to achieve its own sovereign priorities.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Dated this 13 day of October, 2015.

Brian Gustafson

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ______

DECLARATION OF KAREN HAYS

STATE OF GEORGIA
COUNTY OF CLAYTON

I, Karen Hays, hereby declare as follows:

1. I am Chief of the Air Protection Branch (APB) of the Georgia Environmental Protection Division (GA EPD). I have been employed by GA EPD for 17 years, holding a number of positions in the APB. As a part of my duties as Chief, I am responsible for overseeing GA EPD's preparation and implementation of state plans to comply with requirements of the federal Clean Air Act (CAA) and the air quality regulations promulgated pursuant thereto by the United States Environmental Protection Agency (EPA).

2. Based on my experience, I have the personal knowledge of and understand the many steps the State will need to undertake in response to EPA's final rule, *Carbon Pollution Emission Guidelines for Existing Stationary sources: Electric Utility Generating Units,* ("111(d) Rule" or "Rule"), including preparing a state plan to implement this Rule. Based on my review of the final Rule, I have determined that development and implementation of the state plan to implement the 111(d) Rule will be the most complex and time consuming rulemaking ever undertaken by GA EPD. The challenge is made even more complicated by the substantial changes in the 111(d) Rule between the proposed and final Rule, and the Rule's unprecedented reliance on control measures that extend beyond the affected fossil fuel-fired electric generating units

3. The utilities that provide electricity in Georgia include: (a) Georgia Power, an investor-owned utility; (b) Oglethorpe Power, owned by 38 electric membership cooperatives (EMCs); (c) the Municipal Electric Authority of Georgia (MEAG), a public power entity created by an Act of the Georgia General Assembly in 1975 that represents 49 municipal utilities; (d) Dalton Utilities and (e) several independent power producers. Additionally, ten counties in north Georgia are served or partially served by the Tennessee Valley Authority (TVA). Georgia Power is regulated by the Georgia Public Service Commission (PSC). The PSC has limited regulatory authority over the EMCs and municipal utilities in the state. There is no single regulatory entity that determines how electricity is generated and distributed in Georgia, which makes developing a state plan applying to all Georgia utilities extremely challenging.

4. The 111(d) Rule is structured to encourage increased reliance on renewable energy sources of electricity in order to achieve significant reductions in carbon dioxide emissions from fossil fuel-fired electric generating units. This has the potential to disproportionally impact smaller utilities in Georgia. Small utilities that serve small municipalities or rural communities may be left with stranded coal assets at the same time that they are required to invest in additional renewable energy capacity. These additional costs will be borne by their small base of rate payers and impede economic development in these areas. Developing a state plan that does not disproportionately impact small communities served by small utilities will be extremely challenging.

5. EPD does not have the regulatory authority to: 1) set state energy policy; 2) require utilities or other entities to use natural gas instead of coal to generate electricity; or 3) require utilities to obtain electricity from renewable energy sources. Action by Georgia's state legislature and other state regulatory entities may be required to fully implement the Rule. Absent a stay from this Court, evaluation of potential legislative changes to statutes GA EPD is unfamiliar with, since we are not typically governed by them, would be very resource intensive. Likewise, coordination with state regulatory entities that GA EPD does not normally work with, and therefore does not have established relationships or an understanding of their existing rules and processes, will take significantly more time than normal Air Quality Rule revisions do in order for GA EPD to meet the state plan submittal deadlines of this Rule.

6. The resources necessary to develop and implement the Rule are unprecedented. Approximately 20 GA EPD staff members are involved in analyzing various aspects of the Rule, expending over 5,000 hours on this effort to date. This work includes but is not limited to understanding the building blocks that constitute EPA's determination of "Best System of Emission Reduction", and participating in conferences, seminars and meetings with EPA, utilities, Georgia Public Service Commission staff, state energy office staff, EMCs, air agency staff from other states, university experts, non-governmental organizations, and other stakeholders. Such an extensive time commitment has been necessary for GA EPD staff to gain even a basic understanding of the Rule and the energy infrastructure. GA EPD staff are in the position of developing a state plan that will have long lasting and profound effects on the energy infrastructure and ultimately what Georgia citizens pay for electricity. Given the sweeping nature of this rule relative to all previous air rules and the significant impact implementation may have on Georgia ratepayers and the state's overall economic competitiveness, GA EPD will be required to devote even more resources to fully understand the final rule, assess the multiple compliance pathways to determine the least costly course, and ultimately develop a state plan. This effort is diverting GA EPD resources from work on other Clean Air Act requirements.

7. Absent a stay from this Court, GA EPD must immediately begin work on developing a state plan due to the complexity of the Rule. 40 CFR 60.5760 and 40 CFR 60.5765 of the Rule require an initial state plan to include a demonstration that the state has evaluated multiple state plan approaches and a demonstration of meaningful engagement with stakeholders, including vulnerable communities. Even a cursory evaluation of multiple approaches and a minimal effort for "meaningful" stakeholder engagement will make preparing and submitting an initial state plan by September 2016 extremely challenging.

8. Absent a stay from this Court, GA EPD will need to request an extension until September 2018 for submittal of a final state plan to EPA. The time required to collect stakeholder input, analyze alternatives and design a workable state plan is much greater for this Rule than for other state air quality rules due to the complex nature of the issues and the necessity to coordinate with other state entities with authority and expertise in energy policy and regulation. The state plan will likely require revisions of the Georgia Rules for Air Quality Control. Revisions of the Georgia Rules for Air Quality Control must be adopted by the Department of Natural Resources Board prior to submittal of the state plan to EPA. Completing all of this work within the prescribed timeframe, given all of the other Clean Air Act requirements already imposed upon GA EPD, will be very challenging.

9. Absent a stay from this Court, any potential changes to the Rule resulting from court decisions, which will most likely take several years to decide, will require additional analysis and modification of the state plan developed by GA EPD. Legislative action or actions by other state regulatory entities may be required to implement changes to the Rule. Additional revisions of the Georgia Rules for Air Quality Control may be required. This will result in significant additional costs and a further expenditure of limited state resources.

Executed under penalty of perjury this the 20 day of October, 2015.

Karen Hays

Karen Hays

This the 20 day of October, 2015.

LouAnn Carmichael

Signature of Notary Public

LOU ANN CARMICHAEL NOTARY EXPIRES GEORGIA SEPT 1st, 2019 PUBLIC SPALDING COUNTY, GA

Lou Ann Carmichael

Print or Type Name of Notary Public

My commissions expires: 09/01/2019

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ________

DECLARATION OF ROBERT HODANBOSI, CHIEF, DIVISION OF AIR POLLUTION CONTROL, OHIO ENVIRONMENTAL PROTECTION AGENCY

I, Robert Hodanbosi, declare as follows:

1. I am the Chief of the Division of Air Pollution Control at the Ohio Environmental Protection Agency ("Ohio EPA"). I have served as Chief of the Division for over 22 years and have been a member of the Division of Air Pollution Control at Ohio EPA for over 40 years. As part of my duties, I am responsible for all aspects of Ohio's air pollution control program—compliance

monitoring, permit issuance, regulatory enforcement, and administering for Ohio the delegated aspects of the federal program under the Clean Air Act, as well as Ohio's own air pollution control laws and rules. Among my duties are attainment/nonattainment planning, SIP calls, state implementation plan development, regulation development, and other matters as necessary. In this capacity, I am familiar with Ohio's electric generating units, their generating capacity, and the regulatory and related issues they face, as well as other industrial and commercial sources of air pollution. It will be my and my staff's responsibility to undertake and implement Ohio's response to the U.S. EPA's Section 111(d) Rule.

2. Based on my experience, I have determined that implementing the Section 111(d) Rule will be a complicated and time-consuming endeavor. The Section 111(d) Rule is unlike any other Clean Air Act implementation undertaken by Ohio. Among other things, the Section 111(d) Rule's reliance on measures that require the reduction of demand for a particular source of energy—the substitution of certain types of energy for others in building blocks 2 and 3—are entirely unprecedented for Ohio. The State would be required to expend an unprecedentedly large number of resources to design a State Plan that incorporates these building blocks. The burden on the State in doing so is further aggravated by the substantial changes between the proposed and final rules. The State's

resources would have to be diverted from work on the State's other air pollution activities. See Appendix A.

3. Already, various employees have expended approximately 3000 hours seeking to understand the Section 111(d) Rule and preparing for its potential implementation. This has included reviewing the proposed and final rules, attending webinars held by U.S. EPA, and participating in stakeholder meetings, among other endeavors.

4. Given the complexity of the issues involved and the comprehensive nature of the unprecedented regulatory program, it would not be practical for Ohio to postpone work on a State Plan absent a stay from this Court. It is not proper to expect that Ohio can design an effective interim State Plan in time to comply with U.S. EPA's deadline, which is now September 2016. Waiting to attempt implementation until after the litigation concludes while still complying with U.S. EPA's 2016 deadline would not be feasible.

5. In addition, it is uncertain whether any State Plan will be approved by U.S. EPA and implemented in time for regulated parties to comply with the Section 111(d) Rule's interim goals, making any delay in expending resources impractical. Waiting until litigation on this unprecedented rulemaking is complete to begin work on a State Plan would make it impossible for Ohio to meet the Section 111(d) Rule's interim compliance goals and U.S. EPA's deadline. Ohio

must now determine and evaluate the mechanisms needed to comply with the rule. This will include an evaluation of any necessary legislative changes to the Ohio Revised Code. It also remains uncertain whether Ohio EPA or any other state agency has authority or jurisdiction to demand an out-of-state entity such as PJM (the electric grid manager for Ohio) to modify their current practice of determining which plants to operate and supply power to the grid that supplies electricity for Ohio citizens and businesses.

6. Absent a stay from this Court, planning and compliance for the Section 111(d) Rule, including designing a State Plan, would require an enormous ongoing amount of human resources. Preparing and submitting a timely plan would require various dedicated Ohio EPA staff members, as well as significant resources from other state agencies, stakeholders, and potentially the legislature. As the new 40 C.F.R. § 60.5760 and 40 C.F.R § 60.5765 make clear, any possible extension from the September 6, 2016, deadline would require Ohio to provide a submittal that identifies and describes the final plan approach under consideration and the opportunity that Ohio provided for comment from relevant stakeholders on this approach.

7. Absent a stay from this Court, if Ohio endeavors to adopt a multi-state approach to comply with the Section 111(d) Rule, Ohio would need to enter into either a memorandum of understanding or agreement with the other states. Ohio

has limited experience in pursuing this type of agreement with other states under the Clean Air Act, and anticipates that a significant amount of time would be required to negotiate and reach consensus on the content of such an agreement with other state agencies such that the final agreement meets U.S. EPA approval.

8. Absent a stay from this Court, implementation of the Section 111(d) Rule could require legislative changes, which are uncertain and would require the substantial expenditure of Ohio resources that must be spent in the next year. Consideration of which legislative changes might be necessary must begin immediately. The Section 111(d) Rule could require a sweeping change to the Ohio EPA's authority beyond any other previous requirements under the Clean Air Act.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Executed on August 11, 2015 Robert Hodanbosi

Appendix A
Upcoming Clean Air Act State Implementation Plan Activities

1. Sulfur dioxide Consent Decree designations for certain unclassifiable area sources.
    a. Required under March 2, 2015 Northern district of California, enforceable agreement order between EPA and Sierra Club/NRDC.
    b. In a May 20, 2015 letter to the Governor, U.S. EPA provided a schedule for completing designations for these areas around these sources. The letter provides it as an option for States to submit recommendations, but CAA Section 107(d)(1)(A) requires governors to submit initial designations. Ohio has yet to submit designations for these areas.
    c. State recommendations are due September 18, 2015.

2. Remaining sulfur dioxide unclassifiable area source designations.
    a. Required under 79 FR 27446 – Proposed Data Requirements Rule and May 20, 2015 Memo (Stephen Page to Regional Air Division Directors, "Updated Guidance for Area Designations for the 2010 Primary Sulfur Dioxide National Ambient Air Quality Standards").
    b. Schedule and process for designating unclassifiable areas.
        i. January 1, 2016: provide lists of sources to be modeled or monitored.
        ii. July 1, 2016: Submit monitoring plan for monitored sources.
        iii. January 1, 2017: Begin operation of monitors.
        iv. January 13, 2017: Submit modeling analysis and recommended designations for modeled sources.
        v. December 2017: USEPA will finalize designations with additional input from States during the 120-day letter notification.
        vi. August 2019: Attainment demonstrations due for modeled areas.
        vii. Mid 2020: Designations for monitored areas. States will be required to provide recommendations prior to this.
        viii. August 2022: Attainment demonstrations due for monitored areas.

3. Completion of sulfur dioxide attainment demonstration and revisions to federally enforceable regulations.
    a. Due April 4, 2015 but was delayed due to significant resource allocation during Clean Power Plan proposal. Submittal by October 4, 2015 necessary or Ohio's submittal can be found incomplete and a Federal Implementation Plan clock can be initiated.

4. Particulate Matter (PM2.5) infrastructure SIP for the 2012 PM2.5 standard.
    a. Required under CAA Section 110(a)(1)
    b. Due December 13, 2015

5. PM2.5 attainment demonstration for the 2012 PM2.5 standard.
    a. Required under CAA Section 110(a)(1) and Section 189.
    b. Due October 15, 2016

6. Redesignation and maintenance plans for two areas under the 2008 ozone standard
    a. Requirements contained in CAA Section 107(d)(3)(E)
    b. Areas should be redesignations as soon as practicable after attaining the standard. These areas attained at the end of 2014. Typically takes 6-9 months to prepare a redesignation request for submittal that fulfills the CAA requirements.

7. Redesignation and maintenance plan or extension request for one remaining area under the 2008 ozone standard.
    a. If this area attains at the end of the 2015 calendar year, a redesignation request will need prepared (see item 6 above), or if the area qualifies, an additional extension request will need prepared. If the area does not qualify, more extensive attainment planning may be necessitated.

8. Redesignation and maintenance plans for two areas under the 2008 lead standard.
    a. Requirements contained in CAA Section 107(d)(3)(E)
    b. Areas should be redesignations as soon as practicable after attaining the standard. These areas attained at the end of 2014. Typically takes 6-9 months to prepare a redesignation request for submittal that fulfills the CAA requirements.

9. 2015 ozone standard.
    a. Designations required under CAA Section 107(d)(1)(A) and attainment plans required under Section 110(a)(1) and Section 182.
    b. Projected to be finalized in October 2015. State recommendations on nonattainment will be due within 1 year. Designations complete within the following year. And state attainment plans would be due within 2 years of designations.

10. Transport SIPs for 2008 ozone standard.
    a. Required under CAA Section 110(a)(1) and Section 110(a)(2).
    b. Notice of Data Availability signed on July 23, 2015. States must submit comments by September 23, 2015.
    c. Transport SIP requirements expected to be proposed in 2015. States will need to prepare comments on the proposal and then be required to prepare SIPs to address requirements in this rule once final.

11. Appendix W comments.

a. On July 14, 2015, the Administrator signed a proposal to revise the *Guideline on Air Quality Models*. (Appendix W)
b. States must submit comments by October 27, 2015.

12. Corrections to older 2008 infrastructure SIPs.
    a. Infrastructure SIPs are required under CAA Section 110(a)(1). On May 15, 2015, EPA entered into a consent decree with Sierra Club requiring certain elements of these SIPs be addressed by March 31 and August 31, 2015 and also June 7, 2016. States must prepare submittals to address these elements and provide those to USEPA in time for them to act on these submittals by the consent decree deadlines.

13. Regional Haze 5-year review analysis.
    a. Required under CAA Section 169 and the Regional Haze Rule (64 FRCAA Section 169 and the Regional Haze Rule (64 FR 35714).
    b. Due by March 11, 2016.

14. NOx SIP Call/CAIR non-EGU/CSAPR Corrections.
    a. U.S. EPA's new Cross State Air Pollution Rule (CSAPR) applied to different sources than were covered under both the NOx SIP Call requirements and the Clean Air Interstate Rule (CAIR). States are required to address this discrepancy since U.S. EPA no longer administers the programs that applied to the sources no longer covered under CSAPR.

15. Startup, Shutdown, and Malfunction SIP Call

    a. On June 12, 2015 (80 FR 33840), U.S. EPA issued a SIP Call that requires Ohio to revise rules on emissions from startup, shutdown, malfunction and scheduled maintenance
    b. Revised rules to U.S. EPA are due within 18 months.

16. Cincinnati Area PM2.5 RACT/RACM Study

    a. As a result of the recent U.S. Sixth Circuit Court of Appeals July 14, 2015 decision to stay the Cincinnati area redesignation of the 1997 PM2.5 standard, Ohio will need to prepare a study of Reasonable Available Control Technology/Reasonably Available Control Measures (RACT/RACM).

    b. The RACT/RACM study requires that Ohio EPA examine all major sources of PM2.5 and determine if the control of the sources are RACT/RACM. An additional redesignation request will have to be submitted with the RACT/RACM analysis.

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. _____

DECLARATION OF RICHARD A. HYDE, P.E., EXECUTIVE DIRECTOR, TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

I, Richard A. Hyde, P.E., declare as follows:

1. I am the Executive Director of the Texas Commission on Environmental Quality ("TCEQ" or "agency"), a position I have held since January, 2014.

2. The TCEQ is one of the largest environmental agencies in the United States. My agency has primary authority for implementing and enforcing air quality planning and permitting, water quality, water supply, water availability, remediation, municipal solid waste, radioactive waste, and hazardous waste programs in the State of Texas. TCEQ has approval to administer every major federal environmental program in Texas.

3. In Texas, Executive Agencies under the direction of the Governor have responsibility to implement their specific legislative directives. The TCEQ is the Executive Agency in the state of Texas with responsibility for air quality, including the submittal of state plans to the United States Environmental Protection Agency ("EPA"). The Public Utility Commission of Texas ("PUCT") is the Executive Agency responsible for ensuring the provision of reliable, low cost electricity to consumers.

4. As Executive Director, I am the Agency's chief executive, reporting to the Governor-appointed Commissioners.

5. Among my responsibilities are recommending to the Commission any revisions to the state implementation plan ("SIP") required under §110 of the federal Clean Air Act ("FCAA") in order to demonstrate attainment and maintenance of the federally promulgated National Ambient Air Quality Standards ("NAAQS") and to protect visibility. I am also responsible for directing the enforcement of new source performance standards ("NSPS") adopted under §111(b) and for overseeing the development of state plans as required by §111(d) of the federal Act. I have followed EPA's proposed and final rules to implement §§111(b) and (d) as applied to carbon dioxide emissions ("CO_2") from new and existing electric generating units ("EGUs"), respectively. I also supervised staff that developed TCEQ's detailed comments on those rules as proposed. Accordingly, I have personal knowledge and experience to understand what steps the State of Texas has taken and would need to take in developing its response to the final rules for existing EGUs, titled, "Carbon Pollution

Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" rule (the "Rule"), as signed by the EPA Administrator and published on the EPA website on August 3, 2015. These steps include providing commission and legislative briefings on the Rule requirements, consulting with other state agencies, providing draft legislation and further legislative support if requested, and developing rules as necessary.

6. My opinions in this declaration have been informed by briefings from the TCEQ professional engineering, legal, and technical staff, in addition to meetings with other stakeholders concerning the proposed and final Rule, and discussions with the TCEQ commissioners. I believe that the opinions and statements offered herein are consistent with the opinions and statements of the Commissioners, Dr. Bryan Shaw, P.E., Mr. Toby Baker, and Mr. Jon Niermann.

Summary

7. The Rule establishes stringent limits on CO_2 emissions from fossil fuel-fired existing electric utility steam generating units and stationary combustion turbines, referred to in this declaration as either "boilers" and "turbines," "affected units," or "EGUs" generally. Because TCEQ is not aware of any proven, existing technology that will permit existing EGUs to meet these emission limits, it is my understanding that the ways in which electricity is generated, transmitted, and consumed in Texas will need to change.

8. The Rule requires that Texas file a State Plan (or participate in a multi-state plan) or be subject to a yet to be finalized Federal Plan. Any State Plan submittal

will require unprecedented coordination between the TCEQ, the Governor of Texas, the PUCT, the entities with responsibilities concerning electric generation, transmission, and distribution within Texas (Electric Reliability Council of Texas ("ERCOT"), Southwest Power Pool ("SPP"), the Midcontinent Independent System Operator ("MISO"), and the Western Electricity Coordinating Council ("WECC")), the State Energy Conservation Office ("SECO"), the Railroad Commission of Texas ("RRC"), lawmakers, and stakeholders, including owners and operators of affected units, local government officials and the public. Any State Plan developed through this coordinated effort would then be submitted by the Governor of Texas or his designee to the EPA.

9. The Rule requires that a State Plan be filed by September 6, 2016, less than one year from final publication of the Rule. Though the Rule does provide for up to a two year extension for the submittal of a final State Plan, the application for an extension is still due on September 6, 2016 and requires significant work and decisions that must still be made by the state. Regardless of whether Texas plans to submit its State Plan or ask for an extension, TCEQ, and other State agencies, must begin planning how to comply with the Rule immediately.

10. The possibility of a federal plan does not relieve the pressure on Texas to develop a State Plan. EPA's proposed rule for a Federal Plan (which would be effective if the State does not submit its own plan that is approved by EPA) is only in the comment stage and will not be finalized any sooner than Summer 2016. ("Federal Plan

Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or before January 8, 2014, Model Trading Rules; Amendments to Framework Regulations") ("proposed Federal Plan"), as signed by the EPA Administrator and published on the EPA website on August 3, 2015.) Because Texas does not know what the final Federal Plan will require, and cannot properly evaluate its effects, Texas must begin working on a potential State Plan immediately.

11. Therefore, the Rule is placing an immediate, significant resource burden on the TCEQ. Among other things, the Rule requires the agency, in coordination with the PUCT and other state agencies, to make immediate, fundamental decisions about Texas's environmental and energy policy within a year, with repercussions that could affect Texas's citizens, government, and economy for decades to come. The Rule requires the TCEQ and other state agencies to devote myriad staff to consider, formulate, and implement a State Plan, if the state chooses not to accept the Federal Plan.

Background about the Rule

12. The Rule establishes stringent limits on CO_2 emissions from *existing* EGUs. These limits are expressed as "performance rates" in Table 1 of the Rule. The limits for boilers also apply to integrated gasification combined cycle ("IGCC") units, which gasify coal to "syngas," and then burn that syngas in a conventional combustion turbine, although there are no such units operating in Texas; in fact, there are only a few around the U.S., all in the demonstration stage. The limits for existing stationary

combustion turbines apply to natural gas combined cycle ("NGCC") turbines and combined heat and power combustion turbines; simple cycle combustion turbines are exempt from the final rule.

13. The Table 1 performance rates are expressed as pounds of CO_2 per net megawatt-hour, or "lb/MWh." EPA imposed two limits for each of the two source categories, with an interim to be phased in over 2022 – 2029 and the final by 2030. The interim and final rates for boilers (and IGCC) are 1534 and 1305 lb/MWh, respectively. The corresponding interim and final limits for turbines are 832 and 771 lb/MWh, respectively. Because these are rates of emissions expressed as lb/MWh, if the rates are applied to an individual EGU, that EGU cannot merely run less often to meet the standard.

14. It is noteworthy that under the Rule, CO_2 emission performance rates for *existing* EGUs (boilers and stationary combustion turbines) are *more stringent* than the emission performance standards adopted by the EPA for *new or reconstructed* units of the exact same type. This is contrary to how EPA has implemented §111(d) in the past.

15. As a practical matter these standards are not achievable at any individual existing EGU through the traditional application of retrofit control technology considering technological and economic feasibility. I have come to this conclusion by consideration of several factors, including (a) consultation with other engineering experts on my staff, who regularly review the performance capabilities of power plants for purposes of undertaking best available control technology analyses in support of

the agency's permitting functions; and (b) EPA's establishment of a NSPS that sets emission rates significantly higher than those listed in Table 1 for existing sources.

16. In the absence of a practical retrofit control technology option, the only option remaining for the State of Texas to meet either the individual emission performance rates or the optional statewide goals is through requiring shifts in electricity generation—the same means assumed by the EPA in establishing those limits—likely also coupled with some form of emissions- or generation-based trading program.

17. EPA established its emission standard under the Rule not by using the traditional method of examining the best system of emission reductions "(BSER") that can be applied to each EGU as contemplated by Section 111, but rather established emission performance rates for existing units based largely on EPA's projections of shifting generation from steam generating units to natural gas combined cycle units and increased renewable energy generation—effectively defining BSER as the electric grid as a whole. It has been the TCEQ's understanding that BSER is supposed to be technology based, with due consideration of cost and other factors, when setting the emission rates under Section 111. Moreover, it has been the TCEQ's understanding that under Section 111(d), the states set the standards for sources within their jurisdiction, with EPA's role to issue emission guidelines for states.

18. The Rule includes alternative compliance options, expressed as separate and individualized mass-based or rate-based goals for each state. EPA derived these

goals by applying the performance rates in Table 1 to the generating mix of the affected units in each state. Table 2 of the Rule expresses these goals as pounds per net MWh, and Table 3 expresses them as total tons.

19. Because no EGU can practically meet the Rule's emission performance rate established in Table 1 (regardless of whether a State Plan or the proposed Federal Plan is utilized), the only way to meet these emission levels will be to reorganize the state's electric grid by reducing generation from certain facilities, increasing generation from others, and investing in and constructing new generation facilities. But this will likely not be achievable without also implementing an emissions- or generation-based trading system.

Absent a Stay, the Rule Will Cause Texas to Forfeit Sovereignty Over its Environmental and Energy Regulatory Programs.

20. In order to make an informed decision about whether to file a State Plan or submit to the yet to be finalized Federal Plan, the TCEQ and other state agencies, such as PUCT, must begin allocating, time, effort and resources to determine how to comply with the Rule. This due diligence work must begin immediately.

21. The Rule allows the Governor of Texas only until September 6, 2016, to submit Texas's State Plan. EPA may grant states a 2-year extension provided the requesting state explains why it needs more time, identifies the final plan options it is considering and progress made to date, and it has planned for and engaged with stakeholders, including "vulnerable communities," in the preparation of the initial and

final plans. In practice, however, Texas has less than one year to make the critical decisions that will dramatically affect its citizens, government, and economy for decades to come.

22. A threshold decision Texas must make, first and foremost, is whether to submit a State Plan. Under the Rule, if Texas chooses to not submit a State Plan, EPA will impose a Federal Plan. Importantly, as of today, EPA has only issued a proposed Federal Plan, which will not be made final according to EPA until summer 2016. This means that Texas will have virtually no time to review the final Federal Plan to decide whether to accept EPA's Federal Plan or to begin developing, documenting, and adopting its own State Plan by the deadline for either a final plan or a request for extension (September 2016). This situation leaves Texas little choice but to begin allocating, time, effort and resources immediately.

23. Based on my knowledge and experience, the generation, transmission and reliability of electric power is not governed by the FCAA, but instead is governed by the Federal Power Act and the Federal Energy Policy Act of 2005, which reserve specific authority to states, instead of the federal government. While the TCEQ has authority for air, water and waste issues arising from the construction and operation of EGUs, the PUCT is the state agency in Texas that is responsible for ensuring the provision of reliable, low cost electricity to consumers.

24. As discussed above, since no proven, existing technology will allow an EGU to meet the emission levels established in the Rule, it is likely that electric

generation will have to be shut-down, curtailed and shifted to other resources. Moreover, it is likely that an emission-trading program will need to be developed in order to meet the statewide emissions levels. In fact, the proposed Federal Plan would implement such an emissions trading system. Under an emissions trading system, non-emitting renewable generation would produce emissions credits, which could presumably be used to offset fossil fuel generation, or sold to fossil fuel generators.

25. The TCEQ currently has no regulatory program or mechanism to inventory or track generation and/or CO_2 emissions, including for renewable sources that do not emit CO_2 or other pollutants. There also is no regulatory program to make allocations and/or assign and enforce emission limits for CO_2 in a manner that will comply with the Rule. It will require unprecedented coordination between the Governor of Texas, the TCEQ, the PUCT, the ERCOT, SPP, MISO, WECC, the SECO, the RRC, lawmakers, and stakeholders, including owners and operators of affected units and renewable energy sources, local government officials and the public.

26. Compliance with the Rule (or even the Federal Plan) will have to take into account the way Texas' electric market is structured. My understanding is that Texas has adopted a competitive generation system, in which the most cost-competitive (cheapest) source available at any time is the generator allowed to provide the power where and when needed. Because EPA has finalized emission performance rates that can only be achieved by prioritizing generation from sources that do not use fossil fuels, any Plan—whether State or federal—will require those who produce electricity using

fossil fuels to subsidize renewable generation to compete with it. Therefore, in order to achieve the final emission performance goals, Texas will be required to make fundamental changes in its energy policy to force shifts in the generation of electricity from coal-fired EGUs to NGCC and carbon-neutral generation resources.

27. Developing a State Plan will be complicated and will require the TCEQ, along with other agencies, to apply significant time, effort and resources. If Texas chooses to submit a State Plan, at a minimum, the State Plan will likely need to:

- Identify all EGUs and affected units;
- Impose (and demonstrate that) emission standards for each affected unit cumulatively will achieve the state emission goals;
- Provide a commitment to include corrective measures that will ensure compliance with state emission goals if necessary to achieve the emission goals;
- Establish appropriate triggers to ensure compliance;
- Establish schedules for compliance; identify all applicable monitoring, recordkeeping, and reporting requirements for each affected unit; set requirements for state reporting to EPA;
- Demonstrate that each affected unit's emission standard is quantifiable, non-duplicative, permanent, verifiable and enforceable; and
- Identify other specific requirements for rate-based, mass-based, or other state measures-based plans.

28. If the State wishes to or needs to establish rate-based standards on individual affected units different from those in Table 1 or the Texas specific limit in

Table 2 or the Rule, the Plan will also be required to include a projection of future CO_2 emission rates and information for each affected unit concerning:

- Annual generation;
- CO_2 emissions;
- Fuel use;
- Fuel prices;
- Fuel carbon content;
- Fixed and variable operations and maintenance costs;
- Heat rates;
- Electric generation capacity and capacity factors;
- Any planned new electric generating capacity;
- Potential for unplanned new electric generating capacity;
- Implementation timelines for EGU-specific actions;
- All wholesale electricity prices;
- Geographic representations appropriate for capturing impacts and/or changes to the electric system;
- Anticipated electricity demand forecasts at the state or regional level;
- Emission rate credit or emission allowance prices, if applicable;
- Identification of state-enforceable measures with electricity savings and renewable energy generation in MWh, expected for all individual and collective measures;

- Planning reserve margins; and
- Any other assumptions used in the demonstration to project that the emission goal will be achieved.

29. If the state decides to implement a rate-based program, then the state must create a new accreditation program for independent verifiers to review emission reduction credit ("ERC") applications and reports from eligible resources wanting to receive an ERC.

30. In short, a State Plan will need to identify and apply emission standards for all EGUs and affected units and create a program to implement and enforce those standards; and it must include a demonstration that the reliability of the electrical grid has been considered, which will require coordination with multiple entities due to Texas' unique grid structure. All of this will require immediate work, effort and use of resources by the TCEQ and other state agencies in order to develop a potential State Plan. And because the Federal Plan will not be finalized until 2016, the State of Texas cannot wait to start working on the potential State Plan.

Absent a Stay, Texas Must Begin Working Significant Statutory and Regulatory Changes.

31. As a practical matter, in light of the September 6, 2016 and September 6, 2018 deadlines established by the Rule, the TCEQ cannot wait until the litigation challenging the Rule is concluded to create and implement a State Plan.

32. EPA is proposing that Texas can and should regulate facilities in ways never before considered, contemplated, or authorized by the federal or Texas Clean Air Acts. Instead, because the Rule requires Texas to make policy choices about the manner in which electricity is generated, transmitted, and consumed, the State Plan necessarily will be a coordinated effort between the TCEQ and other state agencies and entities with responsibilities concerning electric generation, transmission, and distribution. Therefore, implementation of the Rule will likely require fundamental statutory and regulatory changes that will require the immediate, substantial expenditure of unrecoverable Texas resources.

33. The coordination made necessary by the Rule will likely require changes to the TCEQ's statutory authority to ensure that all required elements of the State Plan could be met in coordination with legislative direction for the TCEQ and other state agencies. The TCEQ, or some combination of state agencies, must have the legal authority to require the emission reductions necessary to meet the state emission performance goal, monitor compliance, enforce each component of the State Plan, and provide required reports to EPA.

34. The Texas Legislature meets on a biennial schedule. The next regular session of the Texas Legislature is scheduled for January through May 2017. While the Governor of Texas has authority under the Texas Constitution to call a special session, this will result in a significant nonrefundable cost to the State of Texas. There is no guarantee that one special session will successfully lead to an agreement to reorder

Texas's longstanding competitive market scheme for generation, especially with the very substantial prospect of the command to do so being undone on judicial review. Due to the complex policy and legal issues arising from the directives of the Rule, multiple or longer special sessions may be necessary.

35. Once the Texas Legislature and the Governor determine the manner in which the State of Texas would change its legal structure for electricity generation, transmission and related regulation, the TCEQ and other state agencies, such as the PUCT, would need to adopt rules, as well as adopt and implement a State Plan. It typically takes 12-24 months for a complex rule to be developed, proposed and adopted by the TCEQ, and additional time may be necessary for this rule given the additional requirements (such as the environmental justice assessment) and the potential for legislative changes. For complex rulemakings, senior staff from each TCEQ office participate as part of the rulemaking team to ensure that applicable federal and state requirements are met, as well as to ensure that potential implementation issues are addressed. Rulemaking team members are responsible for drafting preamble and rule language, preparing for and participating in public meetings, legislative support, reviewing and responding to public comment, and assuring that all administrative rule requirements of the Texas Administrative Procedures Act are met, such as required analysis regarding potential legal takings and major environmental rule analysis. In an attempt to remedy the economic and emission impacts to vulnerable communities created by the massive electric-generation shifts required by the Plan, EPA also requires

states to conduct a poorly defined environmental justice analysis. Because the requirement is so poorly defined, it is difficult to determine the possible resource burden with any certainty, but the Rule's preamble indicates that the analysis and outreach efforts would be extensive.

Conclusion

36. In conclusion, it is my opinion that implementing the Rule will require TCEQ and other state agencies to immediately invest time, effort and resources to develop a State Plan. In my experience, the Rule is unlike any other FCAA rule promulgated by the EPA that states must implement. It is truly unprecedented in both scope and complexity and will require Texas to change the way it regulates emissions and the generation of electricity. In order to submit a State Plan or even ask for an extension by September 6, 2016, TCEQ and other Texas agencies must begin work immediately. Because the Federal Plan is not yet finalized, Texas cannot wait to begin developing its potential State Plan. Developing a State Plan will require significant time, effort and resources and will likely require that existing laws and regulations of the State of Texas will need to be enacted, amended or modified. Texas will not be able to recover these costs.

37. I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

38. Executed on 10-13, 2015.

Richard A. Hyde, P.E.

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. _____

DECLARATION OF BRIAN H. LLOYD, EXECUTIVE DIRECTOR, PUBLIC UTILITY COMMISSION OF TEXAS

I, Brian H. Lloyd, declare as follows:

1. I am the Executive Director of the Public Utility Commission of Texas ("PUCT"). As Executive Director, I am responsible for the daily operations of the PUCT and the management of the PUCT's employees.

2. The PUCT is composed of three commissioners, appointed by the Governor, with the advice and consent of the Texas Senate, for staggered six-year terms. The commissioners are the policymaking part of the agency and issue final decisions on contested cases and rulemakings. The Executive Director is hired by the

commissioners and is responsible for the day to day operations and management of the agency.

3. As explained more fully herein, the PUCT is the principal regulatory authority over electricity markets in Texas. The PUCT's jurisdiction over electricity markets is outlined in the Texas Utilities Code. The PUCT's authority includes comprehensive regulation over the retail and wholesale electricity markets within the Electric Reliability Council of Texas ("ERCOT") and retail electric utilities in parts of the state outside of ERCOT.

4. I earned a Bachelor's of Arts Degree in economics at Louisiana State University and graduated from the University of Texas at Austin with a Master of Science in Economics Degree. I have extensive experience in both the electric and energy industries, and I have extensive experience testifying on electricity regulatory and policy issues before various Texas legislative committees, the Federal Energy Regulatory Commission ("FERC") and the PUCT.

5. As stated by the Environmental Protection Agency ("EPA"), the Rule "establishes final emission guidelines for states to follow in developing plans to reduce greenhouse gas ("GHG") emissions from existing fossil fuel-fired electric generating units ("EGUs"). Specifically, EPA is establishing: 1) carbon dioxide ("CO_2") emission performance rates representing the best system of emission reduction ("BSER") for two subcategories of existing fossil fuel-fired EGUs—fossil fuel-fired electric utility steam generating units and stationary combustion turbines." The term "EGU" is a

term used by EPA that is not defined in the Texas Utilities Code. Power plant owners and operators under Texas law as well as under the Federal Power Act ("FPA") are defined in various ways, depending on the context in which a particular term is used. For purposes of this declaration, I use the terms "EGU" and "power plant" interchangeably and do not use other terms unless it is necessary to explain a specific, relevant aspect of Texas or federal law. I also use the terms "natural gas-fired EGU" and "coal-fired EGU" when necessary to distinguish between generating units fueled by natural gas and coal, respectively.

6. For the reasons outlined below, it is my professional judgment based on my knowledge, experience, and expertise, that the "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" rule (the "Rule") signed by the EPA Administrator and published on the EPA website on August 3, 2015, will cause irreparable injuries to the PUCT and the State of Texas that can be redressed by this Court by staying the Rule during litigation. These irreparable injuries include:

- Expenditure of significant resources, beginning immediately, for unprecedented levels of coordination and planning between the PUCT, Texas Commission on Environmental Quality ("TCEQ"), other Texas state agencies, ERCOT, and other Independent System Operators ("ISOs"). These activities will also divert the resources of each of these entities from their respective core missions;

- Increased risk of electric reliability problems and necessitation of extensive work for the PUCT related to transmission planning and approval of generation plants, due to retirements of coal-fired EGUs that will likely occur well in advance of 2022;

- Seizure of control from state public utility commissions and state legislatures over planning, operations and resource decisions in electricity markets; and

- Insufficient time for the State of Texas to develop a State Plan, given that the Texas Legislature, the PUCT and ERCOT will be required to consider, design and implement extensive modifications to the existing market design for the ERCOT market and take other actions necessary to insure electric system reliability.

7. In the Rule, EPA is attempting to seize control from state public utility commissions and state legislatures regarding the planning, operation, and resource decisions made in electricity markets. It has long been the law of the land that authority over retail electricity markets nationwide (and wholesale markets within the ERCOT power region) are the sole province of state public utility commissions, except where the FPA[1] authorizes FERC regulation. Under the FPA, FERC has jurisdiction over "the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce . . . such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States."[2] Regulation of intrastate electricity markets is clearly the province of the States. As noted by the Supreme Court, "[w]ith the exception of the broad authority of the Federal Power Commission, now the Federal Energy Regulatory Commission, over the need for and

[1] 16 U.S.C. § 824 *et. seq*.

[2] 16 U.S.C. § 824(a).

pricing of electrical power transmitted in interstate commerce…these economic aspects of electrical generation have been regulated for many years and in great detail by the states."[3]

8. Environmental regulation has been limited to specific requirements on specific power plants, and has never been interpreted to grant EPA broad authority to dictate the operation of the entire electricity system in the United States including restrictions on the mix of power plants and other resources operated by utilities. The manner in which power markets are dispatched and directives concerning how much renewable energy should be integrated has never been under the purview of EPA. Rather, these decisions have been and are best left to states and the FERC as experts in these areas. The policies that EPA seeks to force through the Rule—namely renewable energy portfolio standards and cap-and-trade carbon emissions systems—have heretofore always and only been implemented through deliberation in state legislatures and state public utility commissions.

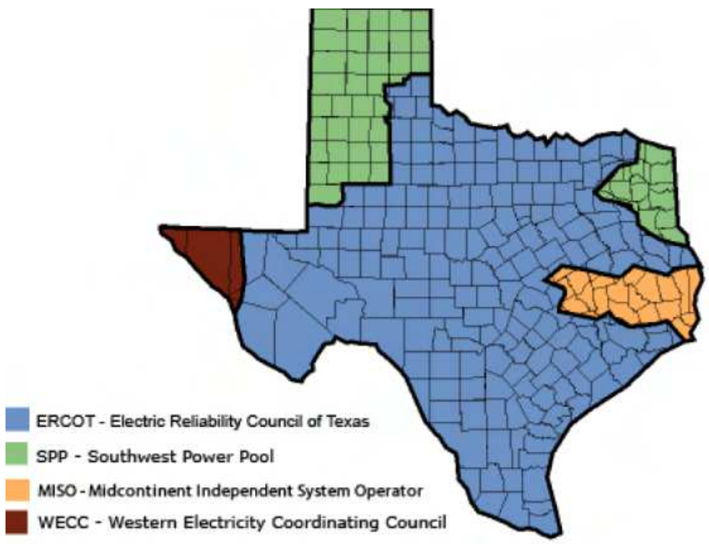
A. Overview of Texas's Unique Electricity Markets

9. Texas is unique among all states in that the majority of the state operates in a vibrant and extremely successful competitive wholesale and retail electricity market (the ERCOT power region), while other portions of the state operate within three distinct competitive wholesale markets that are overseen by the FERC. Texas utilities

[3] *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205 (1983) (citations omitted).

operating in these FERC-regulated markets remain subject to extensive PUCT jurisdiction regarding their retail utility service, as well as their power generation and transmission investments. Texas is also the only state that has utilities that operate in each of the three electrical interconnections in the United States. The map below illustrates the electric power regions in Texas.

Electric Power Regions in Texas



10. For the remainder of this declaration, I will use the term "ERCOT power region" or "ERCOT power grid" to describe the geographic area that exists solely within Texas for which the PUCT is solely responsible for overseeing the operation of wholesale and retail electricity markets. I will use the term "ERCOT, Inc." to describe the membership-based 501(c)(4) nonprofit corporation that has been designated by the PUCT as the ISO that administers the markets in this region.

11. Approximately 90% of Texas electricity consumption occurs within the ERCOT power region. ERCOT, Inc. is the only ISO in the continental United States that operates an electricity market that is wholly contained within one state and is not synchronously interconnected to the remainder of the country. The remaining 10% of electric consumption in Texas takes place in areas outside of the ERCOT power region.

12. ERCOT, Inc. is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the PUCT and the Texas Legislature. ERCOT, Inc.'s mission is to serve the public by ensuring a reliable grid, efficient electricity markets, open access, and retail choice. ERCOT, Inc. is responsible for overseeing the reliable operation of the electric grid for the ERCOT power region of Texas. ERCOT, Inc. manages the flow of electric power to approximately 24 million Texas customers—representing approximately 90 percent of Texas's electric load (i.e., demand for electricity) and approximately 75 percent of Texas's land area. As the ISO for the ERCOT power region, ERCOT, Inc. schedules and dispatches power on a grid that connects approximately 43,000 miles of transmission lines and more than 550 power generation units. ERCOT, Inc. also administers and maintains a forward-looking open market to provide affordable and reliable electricity to consumers in Texas. It manages financial settlement for the competitive wholesale bulk-power market and administers customer switching for seven million premises in competitive choice areas. Existing market policies and investments in transmission in the ERCOT power region have incentivized market participants to maximize the efficiency of the

generation fleet and develop new technologies including renewable generation. With recent investments in transmission, more than 14,000 megawatts of wind capacity have been integrated into the ERCOT power grid, and that number is projected to grow to at least 17,500 megawatts by 2016.[4] By way of comparison, ERCOT's most recent forecast of total capacity in ERCOT for 2016 is approximately 76,000 megawatts of non-wind generation capacity.[5] However, it is important to note that only a fraction of this installed wind capacity, because of its intermittent and seasonal characteristics, is assumed to be available to meet peak demand in the summer months. Specifically, ERCOT's forecast assumes that only 3,000 of the projected 17,500 megawatts of wind capacity—approximately 17%—will be generating energy at the time of peak demand. As will be discussed below, actual production of wind energy during peak demand periods can fall substantially below even this discounted number.

13. Ensuring reliable electrical power is critical to economic stability as well as human health and safety. The Federal Energy Policy Act of 2005 recognized the importance of ensuring reliability of electric grids by creating an Electric Reliability Organization ("ERO"). The ERO function for North America is performed by the North American Electric Reliability Corporation ("NERC"), which oversees a vast set

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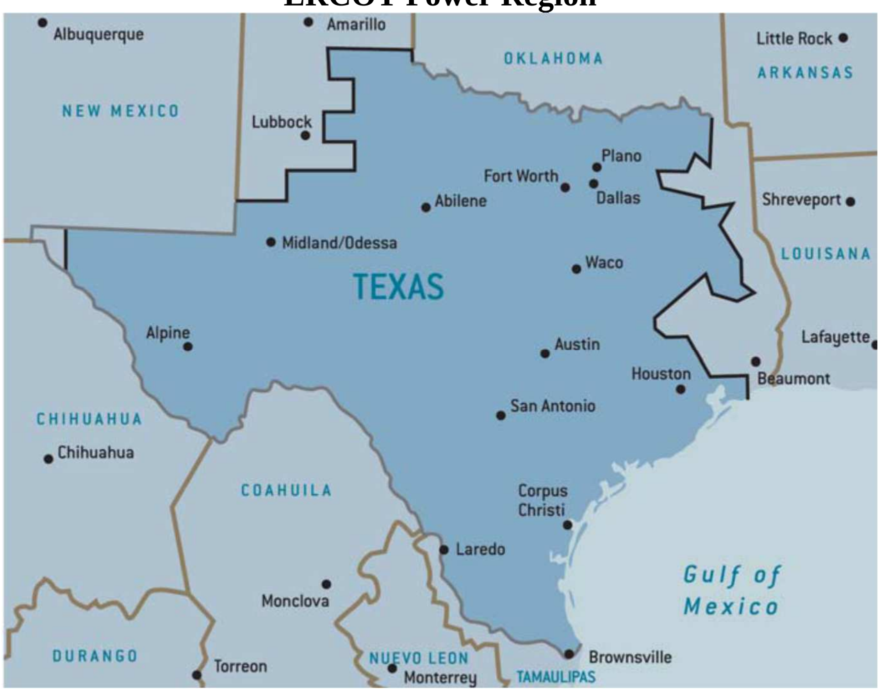
[4] *See* ERCOT, *GIS Report September 2015*, *available at* http://www.ercot.com/content/gridinfo/resource/2015/generation/GIS_REPORT__September_2015_FINAL.xls.

[5] *See* ERCOT, *Capacity, Demand & Reserves Report – May 2015*, *available at* http://www.ercot.com/content/gridinfo/resource/2015/adequacy/cdr/CapacityDemandandReserveReport-May2015.xls.

of reliability standards that are designed to ensure the reliability of the bulk power system. NERC has delegated portions of its oversight to regional reliability monitors; this delegation is approved by FERC. FERC has delegated this oversight to the Texas Reliability Entity ("TRE") as the reliability monitor for the ERCOT power region. ERCOT, Inc. is thus subject to TRE, NERC, and FERC for federal reliability standards. As explained in more detail below, ERCOT, Inc. is also accountable to the PUCT for state reliability standards.

14. The ERCOT power region, identified in the map below, covers most of Texas and includes the major load centers of Houston, Dallas, Fort Worth, San Antonio, Austin, Corpus Christi, and the Rio Grande Valley.

ERCOT Power Region



15. The ERCOT power region is unique in the United States in that it is wholly intra-state and is not directly (also referred to as synchronously) connected to

the two other U.S. grid interconnections (the Western and the Eastern Interconnections). Import and export of power from the ERCOT power region is limited to the capacity of five asynchronous ties linking ERCOT and other interconnections: two between the ERCOT power region and the Eastern Interconnection (with a combined capacity of 820 megawatts), and three between the ERCOT power region and the electrical grid in Mexico (with a combined capacity of 430 megawatts). Flows on these asynchronous ties are scheduled in advance of real-time operations by market participants; however, support from neighboring power regions can be received across these ties during grid emergency events. Aside from these limited asynchronous ties, from an electrical standpoint, the ERCOT power region is an island that must independently ensure its own electric reliability.

16. The power grids operating in Texas that exist outside of the ERCOT power region are located in far-west Texas (part of the Western Electricity Coordinating Council ("WECC")), North Texas and Northeast Texas (part of the Southwest Power Pool ("SPP")), and far-east Texas (part of the Midcontinent Independent System Operator ("MISO")). The non-ERCOT areas of Texas, other than far-west Texas which is in WECC, operate in multi-state competitive wholesale electricity markets that are overseen by FERC. MISO and SPP serve as Regional Transmission Organizations ("RTOs") in these areas and generally perform a role similar to that performed by ERCOT, Inc. within the ERCOT power region. The PUCT has been an active participant in MISO and SPP stakeholder processes encouraging the development of

advanced wholesale electricity market design features, such as ancillary services markets, development of real time and day ahead markets, and active transmission planning.

17. ERCOT, Inc. and the ERCOT power region are also unique among the nation's ISOs and RTOs and electricity markets in that they are subject to very limited and specific jurisdiction by FERC under the FPA. The transmission of electric energy occurring wholly within the ERCOT power region is not subject to FERC's rate setting authority under FPA Sections 205 or 206, nor is it subject to FERC's sale, transfer and merger authority under Section 203 of the FPA.[6] ERCOT, Inc.'s market rules and protocols are also not subject to FERC approval or oversight. Pursuant to Section 215 of the FPA, FERC does have jurisdiction to establish and enforce reliability standards for users of the bulk power system within the ERCOT power region. Finally, under FPA Sections 210, 211 and 212, FERC has limited jurisdiction to order certain entities within the ERCOT power region to interconnect and provide transmission service. Historically, FERC orders issued under FPA Section 212 that are applicable to entities operating in the ERCOT power region have expressly stated that the utilities in the ERCOT power region that are not currently considered public utilities under the FPA will not become public utilities and therefore subject to FERC jurisdiction for any purpose other than carrying out the provisions of FPA sections 210, 211 and 212. See e.g., Kiowa Power Partners, LLC, 99 FERC ¶ 61,251 (May 31, 2002).

[6] *See* FERC, *ERCOT*, http://www.ferc.gov/industries/electric/indus-act/rto/ercot.asp (last visited Oct. 12, 2015).

18. Under Tex. Util. Code Ann. § 39.001, as added in 1999, the Texas Legislature concluded "that the production and sale of electricity is not a monopoly warranting regulation of rates, operations, and services and that the public interest in competitive electric markets requires that, except for transmission and distribution services and for the recovery of stranded costs, electric services and their prices should be determined by customer choices and the normal forces of competition." Thus the Texas Legislature has declared that competitive wholesale and retail electricity markets are the preferred mode of operating electricity markets in the state, and state policy has conformed to this goal since 1999.

19. Under Tex. Util. Code Ann. § 39.151, the PUCT is required to certify an independent organization[7] to ensure the reliability and adequacy of the regional electrical network to ensure a reliable supply of electricity to Texas consumers. The PUCT certified ERCOT, Inc. as the independent organization responsible for overseeing the reliable operation of the electric grid for the ERCOT power region of Texas.

20. Under Tex. Util. Code Ann. §39.151(d), the PUCT is required to adopt and enforce rules relating to the reliability of the ERCOT power region. The PUCT may delegate to ERCOT, Inc. the responsibility for adopting and enforcing such rules, but any rules adopted by ERCOT, Inc. are subject to PUCT oversight and review.

[7] The terms "Independent Organization" and "ISO" are often used interchangeably within the Texas Utilities Code.

While power plants in Texas are also subject to reliability standards promulgated under § 215 of the FPA, the PUCT's authority to promulgate rules related to reliability within the ERCOT power region is independent of those authorities.

21. Under Tex. Util. Code Ann. § 39.151(d), the PUCT has complete authority to oversee and investigate ERCOT, Inc.'s organization to ensure that the organization adequately performs its functions and responsibilities.

22. The policy goals of the Texas Legislature outlined in Tex. Util. Code Ann. § 39.001 have been implemented through the development of a comprehensive framework for wholesale and retail competition for the ERCOT power region including the designation of ERCOT, Inc. as the independent organization responsible for the operation of the wholesale electricity market and as the entity responsible for ensuring the reliability and adequacy of the ERCOT power grid.

23. Inside the ERCOT power region, investor-owned electric utilities were required to separate into generation, transmission and distribution, and retail services companies as part of the transition to retail electric choice. The only service which is still subject to traditional regulation is the transmission and distribution function. The companies providing transmission and distribution service within the ERCOT power grid are known as transmission and distribution utilities ("TDUs"). Notably, as a result of this separation, EGUs within the ERCOT power region now bear the entirety of the risk of owning and operating their assets without guaranteed recovery of their costs or profit through regulated utility rates.

24. In areas of Texas outside the ERCOT power region, retail competition has been delayed indefinitely. In these areas of the state where competition has not begun, electric utilities are still vertically integrated, i.e., they have not separated into generation, transmission, and retail service companies, and are still subject to traditional cost-of-service regulation by the PUCT for their retail rates.

25. Neither an electric utility outside of the ERCOT power region nor a TDU operating inside the ERCOT power region may provide service to the public without a certificate of convenience and necessity ("CCN"). An electric utility or TDU that wishes to construct a transmission line must obtain a CCN from the PUCT before constructing the facility. The PUCT is also authorized to require utilities to construct new transmission facilities if needed to ensure safe and reliable service for the state's electric markets and consumers. Electric transmission CCN regulation by the PUCT is governed by Chapter 37 of the Texas Utilities Code.

26. Electric utilities and TDUs are also subject to cost of service rate regulation by the PUCT under Chapter 36 of the Texas Utilities Code and service quality regulation under Chapter 38 of the Texas Utilities Code.

27. Within the ERCOT power region, ERCOT, Inc. is responsible for ensuring open access to the transmission system, including managing the dispatch of power plants. ERCOT, Inc. largely performs this task through the operation of real-time and day-ahead markets that provide for security constrained economic dispatch.

28. Security constrained economic dispatch operates through ERCOT, Inc., dispatching power plants based upon their bids into ERCOT, Inc.'s administered markets, subject to transmission constraints. Thus, the inherent design of the markets motivates EGUs to bid at a level reflective of their short-run marginal costs, ensuring that in every interval that the power plant operates, its costs are at or below the market clearing price.

29. Tex. Util. Code Ann. § 39.001(c) provides:

> Regulatory authorities, excluding the governing body of a municipally owned electric utility that has not opted for customer choice or the body vested with the power to manage and operate a municipally owned electric utility that has not opted for customer choice, may not make rules or issue orders regulating competitive electric services, prices, or competitors or restricting or conditioning competition except as authorized in this title and may not discriminate against any participant or type of participant during the transition to a competitive market and in the competitive market.[8]

30. Under Tex. Util. Code Ann. § 11.003(18), "regulatory authorities" including the PUCT, may not make rules or issue orders regulating prices or competitors, or restricting or conditioning competition in the ERCOT power region's market except as authorized by Texas law.

B. Absent a Stay, the Rule Will Upend Texas's Competitive Electricity Markets

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[8] TEX. UTIL. CODE ANN. § 39.001(c) (emphasis added).

31. The Rule represents a severe intrusion into the competitive wholesale and retail electricity markets that have operated in Texas since 2002 and is contrary to state policy requirements that, except in very limited instances dictated by the Texas Legislature, competitive forces, not governmental mandates, dictate the power generation mix within Texas. By seeking to mandate severe reductions in the output of EGUs fueled by coal and natural gas and force broader deployment of renewable energy at the expense of this fossil-fuel-based generation, the Rule upends Texas's carefully constructed competitive electricity markets and will prevent power plants that are otherwise economic and functional from generating electricity during many hours of the year. In some cases, the Rule will cause EGUs to completely shut down not because of market forces, but because of the regulatory fiat imposed by EPA that rations the amount of electricity the EGUs are permitted to produce. This lack of power generation will include periods when the operation of those plants is critical to maintaining the reliability of Texas's power grids, leading to a greater risk of blackouts. Absent a stay, the Rule will force EGUs to make irreversible decisions in the next one to three years that will have been unnecessary if the Rule is ultimately overturned on appeal. As discussed in more detail below, I believe the Rule will likely cause some EGUs to retire coal plants before 2022, which increases the risk of electric reliability problems for Texas before 2022 and beyond.

32. The Rule requires a substantial reduction in state-wide CO_2 emissions, and concordantly, generation from EGUs operating within Texas, and will have impacts

within each of the power regions within Texas. EPA's supporting documents indicate that Texas must reduce CO_2 emissions from a 2012 adjusted baseline of approximately 251 million tons to 221 million tons by the first interim period of 2022–2024, and, ultimately, to 189 million tons by 2030. Contrary to the purported "flexibility" that EPA claims exists in the Rule's compliance options, these emission limits absolutely necessitate a substantial reduction in electricity generation from fossil fueled power plants. Expressed as an emissions rate, EPA is requiring a one-third reduction in emissions, which implies substantially reduced output from coal and natural gas plants. EPA's baseline severely understates the reductions EPA is imposing on Texas because many coal plants in Texas had abnormally low output in 2012. Specifically, Energy Information Agency data shows that annual megawatt-hours produced from Texas coal EGUs in 2014 were approximately 10 million megawatt-hours higher than in 2012. The baseline also does not account for continued load growth in Texas that necessitates more electricity generation to meet consumer demand and preserve reliability.

33. The Rule calculates the emissions limitations and corresponding generation reductions through assumptions about heat rate improvements that can be made at existing coal plants, as well as assumptions about the ability of utilities operating in the three electrical interconnections across the country to collectively shift from coal generation to natural gas generation and install additional renewable energy. As discussed by the PUCT in its comments to the proposed version of the Rule, each of these assumptions is incongruent in relation to all three markets operating in Texas, but

especially in relation to the ERCOT power region. In particular, coal-fired EGUs in highly competitive electricity markets are well-motivated already to have made the efficiency improvements implied by the heat rate improvement building block. EPA's assumptions about the re-dispatch of power plants from coal-fired EGUs to natural gas-fired EGUs have been made arbitrarily and are not grounded in power system or pipeline network modeling or meaningful analyses regarding the reliability threats that would materialize from such a shift. The Rule also cavalierly assumes that the natural gas pipeline system has adequate capacity to reliably serve natural gas power plants operating at much higher rates and that such increases in natural gas combined cycle ("NGCC") operation can be authorized without excessive air-quality impacts. It also incorrectly presumes that the transmission grid can readily and quickly accommodate such a shift. Finally, assumptions about the ability of power markets to reliably incorporate large amounts of incremental renewable energy fail to recognize the operational modifications that must result in such markets and, within the ERCOT power market, the existing substantial penetration of these technologies and the unique reliability issues that already exist in the ERCOT power region at the current levels of renewable energy that are unprecedented elsewhere in the country. ERCOT, Inc. has already found a need to procure additional "ancillary services" or back-up fossil fueled capacity in order to reliably integrate the large amounts of wind generation that has connected to the ERCOT power grid.[9]

34. The Rule is fundamentally different from other environmental regulations affecting the electricity industry in that it goes far beyond requiring EGUs to make improvements at a particular plant to lower emissions, but instead mainly seeks to reduce output from fossil-fuel plants and replace it with other sources of electricity that exist elsewhere from the plant itself. Put another way, the primary "emissions control" contemplated by the rule is to not operate high CO_2-emitting power plants and to instead operate other sources of electricity more frequently.

35. Because the emissions performance rates are expressed as a lbs/MWh requirement, an EGU, if that rate were applied to the EGU, could not reach compliance by merely operating the plant less. As discussed by Mr. Richard Hyde in his declaration, these emissions standards are not achievable through traditional retrofit control technology. In fact, carbon-capture technology remains prohibitively expensive for either existing or new power plants to install. For example, in documents submitted to EPA in its permit application, FGE Energy estimated that the addition of carbon capture and sequestration technology would add $1.5 billion to the cost of a new 1,600-megawatt natural gas combined cycle power plant, and *would have been more expensive than*

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[9] *See* ERCOT, *ERCOT Planning and System Costs Associated with Renewable Resources and New Large DC Ties, ERCOT's Response to the Request for Comments issued on August 13, 2014 (Sept. 12, 2014), available at* http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/42647_19_811674.pdf.

the power plant itself.[10] Notably, EPA is not requiring new combustion turbines to install carbon capture equipment.

36. Thus, for an EGU that operates, for example, a single natural gas fired power plant, if the performance rate of 771 lbs CO_2/MWh were applied to that EGU, the EGU would have no choice but to build—or pay others to build—non-emitting renewable generation to substitute for a portion of the output of the plant.[11]

37. For EGU owners that own a diverse mix of power plants, the Rule presumes that these owners will simply change the dispatch of the plants that they own. That assumption represents a fundamental misunderstanding of how organized electricity markets operate. Advanced wholesale electricity markets like the markets operating in Texas operate through unit-specific bidding and dispatch. Dispatch decisions on particular units are made by ISOs on the basis of bids made by the EGUs that, as discussed above, are generally made reflecting the short-run marginal cost of the units.

38. As discussed by Mr. Richard Hyde in his declaration, compliance with the Rule is likely not achievable without the implementation of an emissions or generation-

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[10] *See* Letter from Emerson G. Farrell, CEO & President, FGE Power, to Aimee Wilson, Air Permits Section, EPA Region 6 (March 9, 2014), *available at* http://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/fge-power-cost-estimates030914.pdf.

[11] For example, a 1,000-MW natural gas power plant that operates at a 50% annual capacity factor and has an emissions rate of 1,000 lbs. CO_2/ MWh, would need to build or pay others to build renewable energy capacity sufficient to generate 1.3 million megawatt hours per year to achieve the 771 lbsCO_2/MWh rate. This equates to 425 MW of wind generation operating at a 35% annual capacity factor or 675 MW of solar generation operating at a 22% annual capacity factor.

based trading system. In fact, the proposed Federal Plan would implement such a trading—or cap-and-trade—system. Such systems are intended to produce the same result as if the emissions performance rate is applied to each individual EGU—that is, high emitting EGUs will operate less (or completely shut down) and other sources of generation will operate more frequently. These systems require the purchases of economically valuable permits for emissions that raise the marginal cost of production of the plant and therefore make the power plant less economic compared to other sources. From the PUCT's perspective, either of these compliance options—application of the emissions performance rate to EGUs, or the imposition of a cap and trade system—create the same result: electric generation that would otherwise operate will be restricted from doing so, creating increased costs to consumers and an increased risk to system reliability.

39. The Rule's direction to EGUs not to operate assets that would otherwise be economic with all required environmental controls is in conflict with Texas laws and regulations that prohibit market power abuses, including the withholding of power.[12] As a result, absent a stay, the Texas Legislature, PUCT, and market operators such as ERCOT, Inc., will be required to expend significant resources revising Texas laws and regulations, as well as market rules and procedures.

[12] The PUCT's market power abuse regulations are primarily outlined in PUCT Rule § 25.504.

40. The ERCOT power region also has robust growth in consumer demand compared to other parts of the country, with an expectation of an average of 1.4% annual demand growth between now and 2022. Peak demand growth forecasts suggest a need for a minimum of an additional 850 MW of new power plant capacity each year simply to maintain existing reserve margins.

41. Even though the ERCOT power region is summer-peaking, there are also occasionally winter-weather related reliability strains given the prevalence of electric heating systems in portions of the state. Because of constraints on the natural gas pipeline system that limit the ability of natural gas-fired power plants to maximize output, the operation of Texas's coal-fired power plants are vital during these periods to ensure reliability.

C. Absent a Stay, the Rule Will Likely Cause Degraded Reliability

42. While the Rule does not require actual emissions reductions until 2022, the implied reductions that coal-fired power plants will be expected to make will drastically impact the expected economics of these power plants over their remaining life. As the owners of these power plants are required to make decisions about capital expenditures and the ongoing operation of these plants in planning horizons measured in decades, they likely will now be required to severely discount future cash flows due to this required reduction in operation. It is also important to note that other rules already promulgated (Mercury and Air Toxics Rule) or proposed by EPA (Regional Haze Rule), if they are ultimately upheld by the courts are a significant driver of these

capital expenditure needs. As such, absent a stay of the Rule, owners of these power plants will be more likely to decide to retire power plants rather than make additional capital expenditures that they would not be able to recoup under the restricted operation required by the Rule. These decisions are likely to occur far in advance of 2022, in some cases may occur imminently, and may threaten reliability of the Texas power grid if large retirements are announced in a time period that would not allow adequate time for the construction of replacement power plants or the transmission infrastructure to facilitate power transfers from new sources.

43. For example, the CO_2 reduction required by the Rule, when expressed as a mass reduction requirement, would be greater than the 2012 CO_2 emissions of the six largest coal-fired EGUs in the ERCOT power region, representing nearly 5,000 megawatts of summer capacity. This calculation of the amount of capacity at risk for early retirement is consistent with a study released by ERCOT, Inc. on October 16, 2015 (referred to hereafter as "the ERCOT Study") that analyzed the potential impacts of the Rule on the ERCOT power market. Specifically, the ERCOT study found that the Rule is likely to result in the retirement of at least 4,000-4,700 MW of coal-fired EGUs within the ERCOT region. Importantly, ERCOT, Inc. notes that this result likely represents "a lower bound on the number of potential coal unit retirements" because their model does not require a market rate of return for upgrades that investors

in EGUs operating in a competitive market require.[13] The ERCOT study also notes that model results indicate that in addition to these retirements, several additional coal EGUs operate at extremely low capacity factors (less than 20%) during off-peak months and would likely suspend their operations during these months, increasing the reliability risks during cold weather events that I discussed above. The ERCOT study also found that, consistent with the above discussion regarding investment decisions by power plant owners, many of the units would be retired before 2022 due to the timing of the requirements of other environmental regulations.[14] In some cases, these retirements will occur as early as 2016.[15]

44. The ERCOT power region is a summer-peaking region, with peak demands that have reached a record of 69,783 megawatts in August 2015. During peak periods of the summer of 2015, the ERCOT power region had less than 5,000 MW of excess capacity available to serve customers without resorting to emergency actions on numerous occasions, including periods on seven days during July and August 2015. During portions of those days, the emergency actions would have included implementing emergency demand response programs, and, if those actions were not sufficient to preserve reliability, ERCOT, Inc. would have been required to order the

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[13] ERCOT, *ERCOT Analysis of the Impacts of the Clean Power Plan: Final Rule Update* at 11 (October 16, 2015).

[14] *Id* at 7.

[15] *Id*. at 3.

rotating outages of customers. This illustrates the real potential for degraded reliability that will occur in the ERCOT power region if the Rule results in substantial early retirements of power plants. Plant retirements of this magnitude would have caused a need for emergency actions to maintain reliability in 2015, and in upcoming years would be likely to result in even more severe impacts given the electricity demand growth that Texas is experiencing.

45. While EPA claims that there are numerous "reliability safety valves" in the Rule, these mechanisms do not ameliorate the impacts of the near-term plant retirements that are likely to occur prior to the compliance period in 2022. Additionally, once the compliance period begins in 2022, the reliability safety valve mechanism in the Rule will be of little value because power plants will, at that point, have been closed for a significant duration of time.

46. Decisions to retire coal-fired power plants and associated mining activities are irreversible due to the labor and other resource needs associated with those plants. Power plant and mine operations rely on a labor force with specialized skill sets and expertise and often require site-specific, on-the-job training. Once power plant and mine operations are ceased and workers are laid off, experienced personnel cannot be readily rehired or new personnel quickly trained. Thus, Texas and its power markets will be irreversibly harmed through higher prices and degraded reliability when EGUs are forced to make premature retirement decisions due to the Rule. Decisions by power plant owners to retire these plants early in light of the Rule will require the PUCT,

market operators such as ERCOT, Inc., and transmission owners to immediately start planning and constructing additional transmission in these areas, and/or execute Reliability Must-Run ("RMR")[16] agreements with these power plants to keep them online. The RMR arrangement provides compensation schemes that will impose costs upon consumers. Thus, even if a power plant could reopen following the overturning of the Rule, there will still be costs and infrastructure investment that cannot be recouped. Therefore, these harms will be irreparable.

D. Absent a Stay, the Rule Will Impose Substantial Cost, Time, and Labor Burdens on the PUCT.

47. The threat to reliability resulting from the Rule will impose tremendous burdens on the PUCT and ordinary Texans. Absent a stay of the Rule, the Texas Legislature, the PUCT, and ERCOT, Inc. will be required to consider, design and implement extensive modifications to the existing market design for the ERCOT power region and engage in other activities to ensure that reliability within ERCOT is maintained. These efforts will be extremely costly in time, money, and labor, and but for the Rule, these efforts would not be necessary. If the Rule is not stayed it will be impossible for Texas to undo the changes to its electricity markets that are mandated

[16] RMR agreements are rare, temporary arrangements used by ERCOT, Inc. to provide out-of-market compensation to an EGU that would otherwise exit the market if ERCOT, Inc. determines that the continued operation of the EGU is necessary for voltage support, stability, or management of transmission constraints. RMR agreements are generally short term arrangements to provide time for ERCOT, Inc. and market participants to find alternatives to solve the reliability issues caused by the EGU's closure. Notably, under current regulations, EGUs cannot be compelled to enter into RMR arrangements.

by the Rule, which will result in irreparable harm to the PUCT, ERCOT, Inc., Texas's electric markets and Texas electric customers.

48. EPA has argued in court pleadings that states retain the option to do nothing and await whatever Federal Plan is imposed on a state by EPA. While that may be true for environmental regulators, it is not an option for the PUCT to simply sit by and hope the lights stay on while the validity of the Rule is being litigated. Whether Texas develops a State Plan, or EPA issues a Federal Plan, the impacts and irreparable harm to the PUCT are the same. The PUCT's responsibility to ensure reliable electric service dictates that the PUCT will be forced to address and mitigate the impacts of power plant closures caused by the Rule independent of Texas' decision regarding the filing of a State Plan. The PUCT will be forced to act precisely because EPA does not have jurisdiction to address electricity market design, ensure reliability or engage in transmission planning. The Rule therefore presents two equally untenable options for the PUCT. The PUCT is required to either engage in substantial work that conflicts with Texas law and policy decisions of the Texas Legislature in order to mitigate the impacts of the Federal Plan to protect reliability, or expend substantial resources to assist in the crafting of a State Plan that attempts to mitigate the destructive impacts of the Rule. In either event, only a stay of the Rule can prevent irreparable harm to the PUCT.

49. EPA's attempt to force reductions in the output of coal and natural gas-fired EGUs is inconsistent with Texas's approach to electricity regulation which relies

on the forces of competition to incentivize market efficient development and operation of power plants. In doing so, the Rule effectively requires Texas to fundamentally reorganize its electric grid in the way it generates, transmits, and consumes power. By rationing the amount of electricity that can be produced by fossil-fueled generation assets and forcing expenditures on transmission infrastructure that would otherwise not be necessary, the Rule will result in increased prices and reduced reliability. The ERCOT Study finds that, by 2030, wholesale market prices in the ERCOT power region will rise by up to 44% due to the loss of EGUs that would otherwise continue to operate, and that estimate does not include the costs of adding transmission infrastructure, additional ancillary services, or potential reliability must-run contracts. I discuss why each of these additional costs are likely below.

50. These dynamics exist even in the areas of Texas that are not within the ERCOT power region. The majority of Texas's electricity customers outside of the ERCOT power region are served by investor-owned utilities ("IOUs") subject to the oversight of the PUCT for their retail rates, service quality, and operations. The non-ERCOT IOUs operating in Texas are each part of multi-state utility systems. The non-ERCOT areas of Texas are located in far-west Texas, North Texas, and far-east Texas.

51. El Paso Electric Company ("El Paso"), which is part of WECC, serves far-west Texas. WECC is a non-profit corporation whose primary function, as a Regional Entity through delegated authority by NERC, is to assure bulk electric system reliability in the geographic area known as the Western Interconnection, which is

comprised of fourteen states in the western U.S. as well as two Canadian provinces and Northern Baja Mexico. Peak Reliability is a 501(c)(4) entity that retains registration for, and fulfills the duties of, the Reliability Coordinator, as defined by NERC, and as delegated by the WECC, for its Reliability Coordinator Area in the Western Interconnection. Peak Reliability's Reliability Coordinator Area includes all or parts of fourteen western states including Texas, British Columbia, and the northern portion of Baja California, Mexico.

52. The Panhandle portion of Texas, including the city of Amarillo and areas around Lubbock, is served primarily by Southwestern Public Service Company ("SPS"), which operates within the SPP. SPP is a not-for-profit organization that operates as an RTO with members in nine states that is subject to oversight by FERC and a Regional Entity through delegated authority from NERC. Far-northeast Texas is served by Southwestern Electric Power Company ("SWEPCO"), which also operates within SPP.

53. Finally, in far-east Texas, Entergy Texas, Inc. ("ETI"), operates in MISO, which is a not-for-profit organization that operates as an RTO with members in fifteen states and the Canadian province of Manitoba and is also subject to oversight by FERC.

54. Both MISO and SPP are required by FERC to ensure reliable supplies of power, adequate transmission infrastructure, and competitive wholesale prices of electricity.

55. SPP operates regional security-constrained, economically dispatched markets. This model considers both reliability and economics. Reliability actions and

generation dispatch provide regional solutions to needs over a multi-state area. These solutions are not limited to state boundaries. SPP performs regional transmission planning and directs transmission construction for its member companies. All generator interconnection requests and transmission service requests are directed to and processed by SPP. Transmission planning is a significant function of SPP and the other RTOs. Transmission planning, design, permitting and construction are very time-intensive. In SPP, planning, designing and construction of transmission lines can take up to eight and a half years.

56. Notably, Texas utilities operating in WECC, MISO, and SPP are all on the end of their respective interconnections. Thus, each of the utilities tend to be transmission-constrained, meaning that the existing transmission grid has limitations on how much power can be imported into Texas from other states.

57. Each of the utilities operating in the non-ERCOT power regions of Texas operates fossil-fueled electricity generation units that will be impacted by the Rule. These utilities are required to request and obtain approval from the PUCT to construct new generation plants or transmission facilities.

58. Two of these utilities—namely SPS and SWEPCO—each have large amounts of coal-fired generation. The Rule will require these utilities to develop plans to reduce or replace the output of these plants with new power plants and develop other infrastructure in order to ameliorate the reliability impacts of the Rule. Due to the time

it takes to plan, permit, and construct new transmission and generation resources, these efforts will have to begin well in advance of 2022.

59. However, these efforts are unlikely to be concluded even by 2022. For example, if SWEPCO does not have sufficient capacity in Texas to make up for the forced retirement of some of its coal units, SWEPCO would likely be forced to purchase capacity (assuming such capacity were even available) from outside Texas to serve its customers. Because SWEPCO is located on the western seam between SPP and the ERCOT power region, there is currently insufficient transmission from which to import the capacity that would be needed to replace its retired coal units. As noted above, transmission planning in SPP is a multi-state effort and can take as long as eight and a half years and require approvals from both the SPP and a number of states. EPA has failed to recognize the significant investment in new capacity and new transmission that SWEPCO would likely be required to make under the Rule. This problem would be exacerbated in the winter months when natural gas curtailment issues due to weather are most likely to arise.

60. Additionally, because the SWEPCO system spans multiple states, it is probable that any additional transmission improvements will require approvals from states other than Texas. Should any of the impacted states deny applications to build new transmission lines into Texas, SWEPCO, and ultimately the PUCT, will be unable to ensure reliability to its Texas customers.

61. Because the PUCT will be required to process requests for new power plants and transmission lines even if they are ultimately deemed unnecessary because the Rule is overturned, the PUCT will be irrevocably harmed by having to dedicate and divert resources to these efforts to the detriment of other regulatory work and state policy goals. As discussed below, planning, permitting and construction of transmission in the non-ERCOT areas of Texas will be especially difficult for Texas and will require an unprecedented level of coordination among multiple states within the SPP and MISO markets.

62. While the PUCT generally does not have regulatory jurisdiction over the operations of electric cooperatives and municipally owned utilities, I am aware that a number of cooperatives within Texas receive power from predominately coal EGUs, and thus have similar concerns to those I have discussed with respect to SWEPCO's generation planning. Because the PUCT is required to approve new transmission lines constructed by electric cooperatives and municipally owned utilities, the PUCT will be impacted by the need to dedicate resources to processing these requests in a manner similar to that discussed for other Texas utilities.

E. Absent a Stay, the Rule will have Substantial Impacts on the PUCT's Activities Related to Transmission Planning and Reliability

63. The Rule further contemplates that electric generation unit owners or states will take steps to incentivize or otherwise install large additional amounts of

renewable energy to replace the production from coal and natural gas-fired power plants that will be unable to operate under the emissions limits established in the rule.

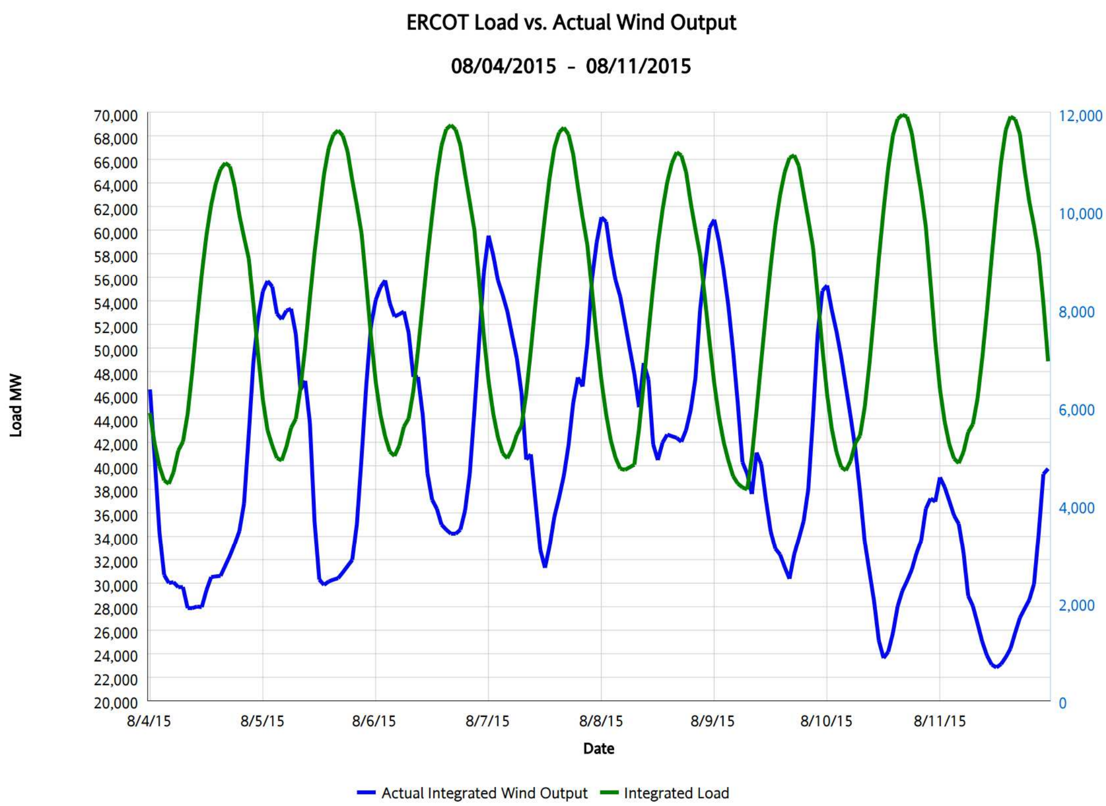
64. The Rule is fundamentally flawed in its assumption that all sources of electricity production are always substitutable. In many cases they are not. Fossil-fueled generation plants often provide services to power grids that intermittent renewable energy sources cannot. The location of power plants also has dramatic impacts on the ability to reliably meet power demand. Thus, it is simply not the case that megawatt hours produced in East Texas at a coal plant can always be replaced one-for-one with renewable energy from a wind farm in West Texas. As ERCOT, Inc. puts it, "[c]oal resources provide essential reliability services necessary to maintain the reliability of the grid. The retirement of coal resources will require studies to determine if there are resulting reliability issues, including whether there are localized voltage/reactive power control issues and the necessity of potential transmission upgrades . . . ."[17]

65. Wind generation in Texas also tends to produce only a fraction of its output during the times of peak demand. For purposes of planning, ERCOT, Inc. presumes that only 12% of wind capacity in West Texas and only 56% of wind capacity along the Texas coast will generate electricity during the summer peak. However, on many peak summer days, actual wind production can be substantially below these

[17] ERCOT, *ERCOT Analysis of the Impacts of the Clean Power Plan: Final Rule Update* at 11 (October 16, 2015).

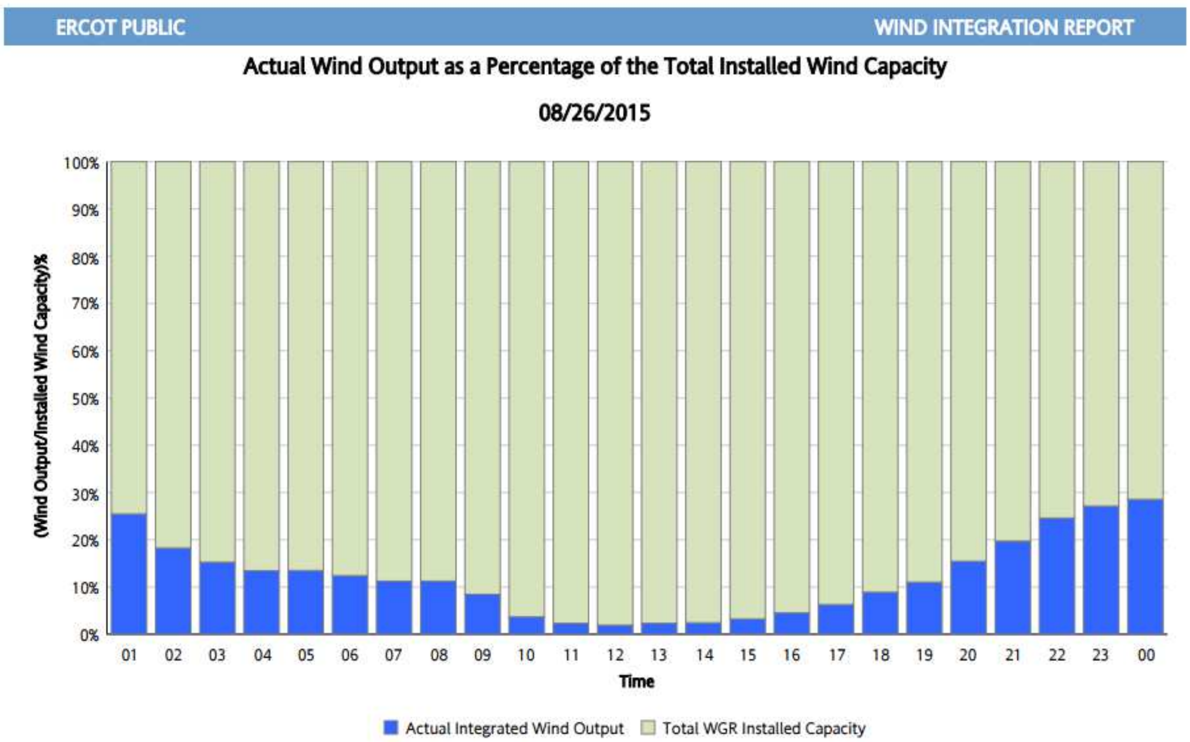
planning estimates. On such days, the availability of fossil generation is critical to maintaining reliability.

66. The following chart[18] illustrates the pattern of wind energy production together with electricity demand in the ERCOT power region on typical summer weeks. Wind energy production (the green line) is generally at its maximum (though still less than 100% of capacity) around midnight, and is generally at its minimum during afternoon hours when demand (the blue line) is at its highest.



[18] *See* ERCOT, *Wind Integration Report: 08/11/2015, available at* http://www.ercot.com/content/gridinfo/generation/windintegration/2015/08/Wind%20Integration%20Report%2008-11-2015.pdf.

67. Illustrated a different way, the following chart[19] shows actual wind production as a percentage of overall wind capacity during a day in August 2015. As can be seen, actual wind production varies throughout the day, never exceeds 30% of installed capacity, and approaches zero percent during the early afternoon hours when demand is rising the fastest.

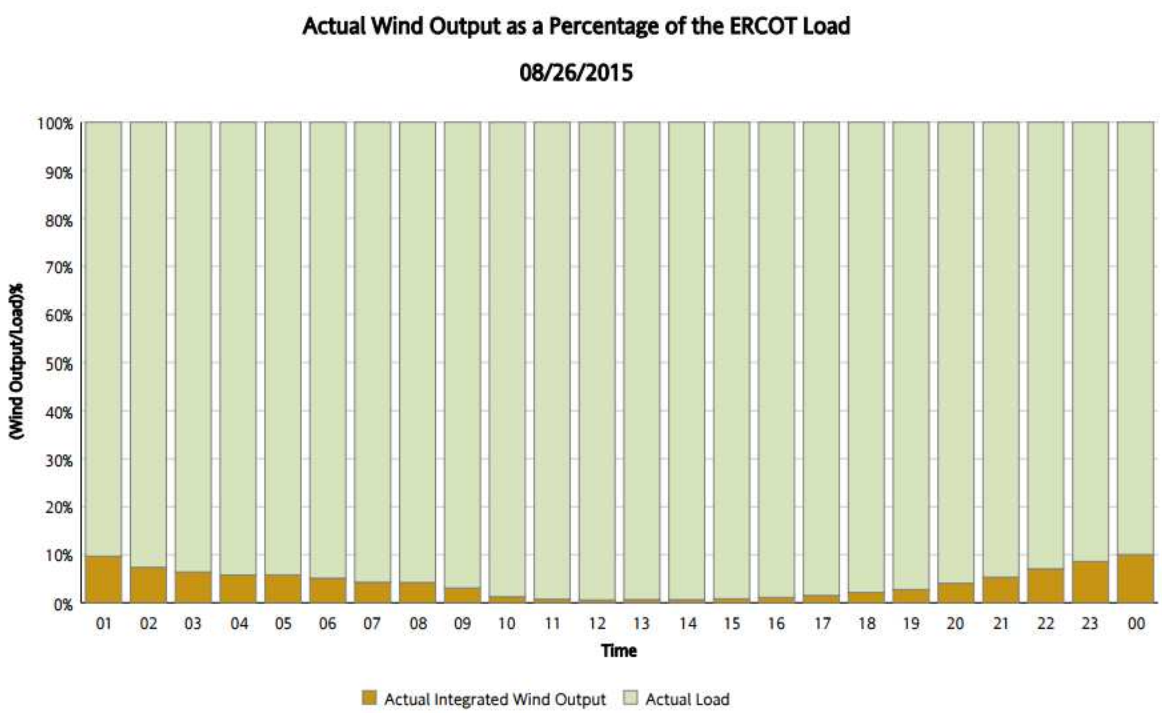


68. Finally, to demonstrate the reliability aspects of this variability, the following chart[20] illustrates actual wind generation as a percentage of total customer

[19] *See* ERCOT, *Wind Integration Report: 08/26/2015, available at* http://www.ercot.com/content/gridinfo/generation/windintegration/2015/08/ERCOT%20Wind%20Integration%20Report%2008-26-15.pdf.

[20] *Id.*

demand on the same day. As can be seen, even though installed wind capacity was approximately 12,000 MW, actual wind production never served more than 10% of total customer demand, and provided virtually none of the energy consumed by customers in the afternoon hours. As discussed earlier, if the Rule forces early retirements of fossil-fueled generation, Texas will experience adverse reliability impacts and challenges on days like this when the intermittent wind generation is unavailable.[21]



69. In Texas, renewable energy sources have generally been developed in remote areas in West Texas due to higher wind speeds. This has required substantial

[21] While solar energy generation has the potential to produce electricity more in line with consumer demand at peak periods, there is currently less than 200 MW of large scale solar energy installed on the ERCOT power grid. Additionally, I have reviewed studies that suggest that maximum solar energy production in Texas is likely to occur around the noon hours, with declines in production occurring in late afternoon, which is the time electricity production peaks.

new transmission investment in order to move electric energy generated by these sources to the major demand centers in the eastern and central parts of the state. This area of the state is also characterized by low customer demand and little dispatchable fossil fuel generation. As such, Texas is currently expending significant effort to address unique reliability needs related to voltage support, system inertia, and stability issues that can arise in such circumstances. It is simply not the case that additional intermittent renewable generation can in all cases interchangeably replace the fossil generation that the Rule will prevent from operating.

70. Tex. Util. Code Ann. § 39.155(b) requires ERCOT, Inc. to submit an annual report to the PUCT identifying existing and potential transmission system constraints and system needs within the ERCOT power region. In support of this and other requirements, ERCOT, Inc. conducts a comprehensive, ongoing transmission planning process to identify the need for additional transmission in the ERCOT power region. In the most recent ERCOT, Inc. report to the PUCT, ERCOT, Inc. identified substantial transmission system improvements needed to accommodate demand growth in the Houston, Dallas Fort-Worth, San Antonio and Rio Grande Valley regions, including needs related to large new industrial projects.

71. Beginning in 2005, Texas embarked on a multi-year plan to dramatically expand transmission infrastructure to support renewable energy known as the Competitive Renewable Energy Zone ("CREZ") transmission project. The CREZ project adopted by the PUCT provided for a total of approximately 18,500 MW of

transfer capacity from West Texas to the rest of the state. This was the maximum amount that the PUCT was willing to approve given concerns about the reliability impacts of renewable energy capacity beyond that amount.

72. From the time the Texas Legislature enacted legislation in 2005 directing the PUCT to designate areas of the state as CREZ's until the final CREZ transmission lines were completed in 2014 was approximately nine years. From May 2005 to December 2013, the PUCT designated CREZ zones, selected transmission providers to build the transmission, and decided 37 contested transmission CCN applications which authorized the construction of 3,589 miles of transmission lines at a cost of approximately $6.9 billion.

73. Thus, even with the advantages described above, the final CREZ transmission line project took nine years from the enactment of Legislative authority, comprehensive planning efforts at ERCOT, PUCT consideration and approval of the lines, to final construction.

74. For generation interconnection requests, ERCOT, Inc. conducts a screening study to determine the proposed generator's impacts on the system. Once the full interconnection studies are performed by the transmission service provider and accepted by all parties, the market participant and transmission service provider may enter into a Standard Generation Interconnection Agreement ("SGIA"). The duration of the interconnection process can vary greatly, generally ranging from one to four years from the start of the process to commercial operations.

75. Again, it is important to note that the PUCT will be forced to expend resources related to this transmission planning unless the Rule is stayed. Even if Texas declines to file a State Plan, the PUCT remains charged with ensuring reliable electric service across the state. Given that the Rule will likely result in potential early retirements of power plants or the early deployment of additional renewable energy, the PUCT will have no choice but to expend resources as EGUs, electric utilities, and ERCOT, Inc. are forced to begin planning for compliance with the Rule. The ERCOT Study highlights that the coal EGU retirements forced by the Rule will result in the overloading of 10 circuits and 143 miles of 345 kilovolt (kV) transmission lines; 31 circuits and 147 miles of 138 kV transmission lines; 6 circuits and 39 miles of 69 kV transmission lines; and almost a dozen transformers. The addition of a similar amount of transmission to relieve these overloads is likely to cost in excess of $600 million (financed by Texas ratepayers) and take at least five years to plan, route, approve, and construct. The ERCOT Study also finds a likely growth in renewable generation comparable to that facilitated by the CREZ project, creating the specter of a need for billions of dollars of additional transmission to fully integrate these resources. The dedication of resources to ameliorate this impact of the Rule will mean the PUCT will be irrevocably harmed by having fewer resources to appropriately deal with other priorities of the state, such as planning for demand growth and conducting our normal regulatory activities.

76. Texas is generally regarded as a jurisdiction where transmission is built relatively expeditiously. This is due to the centralized transmission planning function at ERCOT, Inc. and the PUCT as the sole regulator needed to approve new transmission lines. Even with these advantages, the final CREZ transmission line project took nine years from the enactment of Legislative authority, comprehensive planning efforts at ERCOT, Inc., PUCT consideration and approval of the lines, to final construction. Because the Rule requires the initial reductions in carbon dioxide output in 2022, EPA has not provided sufficient time for Texas to perform a similar analysis and transmission planning related to the reliability impacts of the Rule.

77. Additionally, while the CREZ transmission upgrades provided substantial new transmission capacity to accommodate renewable energy, these new circuits will not provide sufficient capacity to reliably integrate the large additional amount of renewables necessary to meet the requirements of the Rule. EPA's assumed incremental renewable energy generation levels by 2030 for the ERCOT power region is three times the level estimated for 2012 and none of the renewable energy installed prior to 2012 can be used by EGUs or the state to demonstrate compliance. Also, if the locations of new renewable generation do not coincide with CREZ infrastructure, significant further transmission improvements will be required. Given the need to increase the amount of renewable resources in order to achieve compliance with the requirements of the Rule, it is likely that significant new transmission infrastructure would be required to connect new renewable resources.

F. Absent a Stay, the Rule will Usurp Texas's Authority Over Renewable Energy Policy

78. The Texas Legislature adopted a renewable energy portfolio standard ("RPS") in 1999, and increased it in 2005. Under the RPS adopted by the Texas Legislature, all entities in ERCOT that sell electricity are required to either directly own or purchase renewable energy capacity. Entities that do not own or purchase renewable energy capacity are required to purchase renewable energy credits ("RECs") to satisfy the RPS. The PUCT has adopted a rule establishing a REC trading program. Under the REC trading program, RECs may be generated, transferred, and retired by renewable energy power generators certified under the rule, as well as retail entities and certain other market participants. Through the RPS, the Texas Legislature mandated a minimum amount of electric generation capacity from renewable energy sources be installed in the state. Texas has met its existing mandates. In light of this, the Texas Legislature has not indicated a preference to increase these mandates, and considered legislation to repeal Texas's RPS law in the last legislative session.

79. The Rule seeks to usurp the roles of the Texas Legislature and PUCT in determining renewable energy policy in Texas. As discussed in paragraph 36, if the emissions performance rate is applied to EGUs, many EGUs will have no choice but to build new renewable energy capacity, or pay for others to build it on their behalf. The end result is identical to state RPS regulations, except the requirements are dictated

by EPA and not the Texas Legislature and also do not consider other important factors, including cost and reliability, that have been considered by the Legislature.

80. Should Texas elect to file a State Plan, neither the PUCT nor Texas can guarantee that renewable energy resources will grow at a rate sufficient to meet the requirements of the rule without amendments to Texas' RPS, particularly in light of the fact that the Rule only permits states to count new renewable energy resources installed after 2012 for compliance purposes. In fact, EPA makes it clear that voluntary or market driven renewable energy goals will not be considered "state enforceable measures."[22] Thus, in order to provide guarantees that the renewable energy required by the rule will be installed, the Texas Legislature must first decide whether to amend Texas law to impose a new RPS requirement in Texas. The Texas Legislature is next scheduled to meet beginning in January 2017, and I agree with the logistical, financial, and practical challenges that this presents the State of Texas as explained in Mr. Hyde's declaration.

81. The ERCOT Study also highlights a critical factor that EPA has failed to consider. Regardless of whether Texas files a State Plan or has a Federal Plan imposed upon it, there is a limit to the amount of intermittent renewable energy that the ERCOT grid can accommodate. In 2014, 10.6% of the ERCOT power region's annual

[22] EPA, *"Incorporating RE and Demand-Side EE Impacts Into State Plan Demonstrations"*, Technical Support Document, Docket ID No. EPA-HQ-OAR-2013-0601 (July 31, 2015) at p. 16 n. 17.

generation came from wind, and at its highest level of penetration, wind energy served approximately 41% of all customer demand. The ERCOT Study forecasts that the Rule will force significant growth in additional wind and solar resources, which together may comprise 27% of total generation by 2030. "Significant ramping capability and operational reserves" from fossil EGUs is required to maintain grid reliability during these periods of high renewable energy production, but at a high enough level of production, ERCOT, Inc. will likely be forced to curtail renewable energy output to keep the grid stable.[23] As renewable resources are curtailed, production is reduced, and it is more likely that compliance with the Rule cannot be achieved—a scenario that the Rule does not contemplate. These issues are among the factors that the Texas Legislature has been deliberating as it has discusses Texas's existing RPS law and precisely why these issues are properly left to state legislatures and electricity regulators to decide.

G. Absent a Stay, the Rule will Require Unprecedented Coordination Between the PUCT, other Texas State Agencies, ERCOT, Inc., and other ISOs

82. The additional state laws required to implement the Rule in Texas would in turn almost certainly require the adoption of new or amended rules by each affected state agency, including the TCEQ, PUCT, and possibly the Railroad Commission of Texas ("RRC") and would also require interagency contracts or agreements between

[23] ERCOT, *ERCOT Analysis of the Impacts of the Clean Power Plan: Final Rule Update* at 13 (October 16, 2015).

these agencies. The Rule would also likely require changes in operating procedures for all markets operating in Texas and the establishment of carbon dioxide emissions trading regimes—both of which would also be costly and time-consuming processes. If the Rule is not stayed, its will require the expenditure of significant time and resources by Texas state agencies and market operators in Texas.

83. The Rule will require unprecedented coordination among multiple Texas state agencies, including the PUCT, TCEQ, and the RRC. The TCEQ is the Administrator of Texas's air quality program under the Clean Air Act. The RRC is a Texas state agency that serves as the primary regulator of the oil and gas industry in Texas. The RRC: 1) oversees all aspects of oil and natural gas production, including permitting, monitoring, and inspecting oil and natural gas operations; 2) permits, monitors, and inspects surface coal and uranium exploration, mining, and reclamation; 3) inspects intrastate pipelines to ensure the safety of the public and the environment; 4) oversees gas utility rates and ensures compliance with rates and tax regulations; and 5) promotes the use of propane and licenses all propane distributors.

84. The Rule clearly intermingles matters within the jurisdiction and expertise of the TCEQ, PUCT, and the RRC. While TCEQ would likely be the agency delegated authority to submit and monitor compliance with a State Plan, it will need myriad assistance from the PUCT, RRC, and other State agencies in formulating the State Plan. Further, it will be necessary for these agencies to coordinate with the ISOs and RTOs operating in Texas (ERCOT, SPP, and MISO), the WECC and Peak Reliability

regarding the reliability impacts of the Rule. The level of coordination among Texas state agencies and the ISOs and RTOs required under the Rule is significant and will involve the immediate expenditure of considerable time, effort and money in order to meet either the September 2016 or September 2018 deadline for submission of a State Plan. The cost and expense of this coordination effort will cause Texas irreparable harm if the Rule is not stayed.

85. Texas's unique composition of fully-competitive service territories adds an additional layer of complexity and potential for irreparable harm if the Rule is not stayed. Particularly with respect to Texas utilities operating outside of the ERCOT power region, consideration of any State Plan will necessarily involve the PUCT consulting with states in the MISO, SPP, and WECC regions, along with the respective grid operators, to assure that actions taken regarding the State Plan respect reliability concerns and other applicable regulatory requirements and authorities in each of those jurisdictions.

86. Such consultation will need to occur even if Texas ultimately decides to file a Texas-only State Plan because Texas, as well as all of the other states and applicable regulatory authorities such as FERC and NERC, will need to understand the other states' plans in order to properly assess the reliability impacts of those plans. The Rule requires a staggeringly complex level of interaction that involves several state agencies including the PUCT and TCEQ, three distinct RTOs, and all the states within the footprints of those RTOs, the end result of which is that Texas has to accomplish not

only significant intrastate agency coordination but also significant coordination with almost half of the states in the country. In order to meet the deadline for filing a State Plan (September 2016 or September 2018 if an extension is granted) this extremely complex and resource intensive coordination process would have to begin immediately. Obviously, Texas would be irreparably harmed by the expenditure of considerable time and resources needed for this coordinated effort if the Rule is ultimately overturned on appeal.

87. EPA has put Texas in a no-win situation. Texas must either submit a State Plan—and thereby cede its authority over the state policy regarding electricity markets in the state—or risk imposition of a Federal Plan by EPA, which would at a minimum introduce severe distortions into the State's electricity markets, and further, could effectively usurp Texas's authority over its electricity markets with respect to the State's preference for competitive market outcomes. Both are untenable outcomes for Texans.

H. Absent a Stay, Texas will not have Sufficient Time to Develop a State Plan

88. In order to implement the Rule, the PUCT also would be required to amend a significant number of its rules. Some of the rule changes would also require changes in Texas law before they could be adopted by the PUCT. Possible PUCT rule changes resulting from the Rule that have been identified to date include:

- 16 Tex. Admin. Code § 25.51 (Power Quality);
- 16 Tex. Admin. Code § 25.53 (Electric Service Emergency Operations Plans);

- 16 Tex. Admin. Code § 25.54 (Cease and Desist Orders to PGCs);
- 16 Tex. Admin. Code § 25.93 (Wholesale Electricity Transaction Information);
- 16 Tex. Admin. Code § 25.91 (Generating Capacity Reports);
- 16 Tex. Admin. Code § 25.109 (Registration of Power Generation Companies and Self Generators);
- 16 Tex. Admin. Code § 25.172 (Goal for Natural Gas);
- 16 Tex. Admin. Code § 25.173 (Goal for Renewables);
- 16 Tex. Admin. Code § 25.174 (Competitive Renewable Energy Zones);
- 16 Tex. Admin. Code § 25.181 (Energy Efficiency Goal);
- 16 Tex. Admin. Code § 25.183 (Reporting and Evaluation of Energy Efficiency Programs);
- 16 Tex. Admin. Code § 25.200 (Load shedding, Curtailments and Redispatch);
- 16 Tex. Admin. Code § 25.211-213 (Rules related to Distributed Generation);
- 16 Tex. Admin. Code § 25.217 (Distributed Renewable Generation);
- 16 Tex. Admin. Code § 25.235 (Fuel Costs);
- 16 Tex. Admin. Code § 25.236 (Recovery of Fuel Costs);
- 16 Tex. Admin. Code § 25.237 (Fuel Factors);
- 16 Tex. Admin. Code § 25.238 (Purchased Power Capacity Cost Recovery Factor);

- 16 Tex. Admin. Code § 25.251 (Renewable Energy Tariff);
- 16 Tex. Admin. Code § 25.261 (Stranded Cost Recovery of Environmental Cleanup Costs);
- 16 Tex. Admin. Code § 25.361 (ERCOT);
- 16 Tex. Admin. Code § 25.365 (Independent Market Monitor);
- 16 Tex. Admin. Code § 25.421 (Transition to Competition for a Certain Area Outside the ERCOT power region);
- 16 Tex. Admin. Code § 25.422 (Transition to Competition for Certain Areas in the Southwest Power Pool); and
- 16 Tex. Admin. Code §§ 25.501-508 (ERCOT wholesale market design rules).

89. Even if the Texas Legislature passed laws giving the PUCT the authority to adopt or amend existing rules necessary to carry out the mandates of the Rule, the sheer number of rule amendments to PUCT regulations will be a costly, time-consuming, and resource-intensive task. I believe that amending this many rules is an undertaking similar in scope to the rules adoption required in response to the implementation of retail electric competition in the ERCOT power region. Implementing all the rules needed for retail competition in the ERCOT power region took three years, from 1999-2002, and many of the rules required subsequent revisions. Given the complexity and scope of the Rule, I believe that completion of only the regulatory amendments necessary to implement the Rule will take several years.

90. A separate but related implementation issue will be the amending of existing market rules and adoption of new market rules by market operators like ERCOT, Inc. Because the Rule requires fundamental changes to the way electricity markets operate, ERCOT, Inc. will need to adopt or amend numerous market rules to mitigate the impacts resulting from the Rule. Additionally, ERCOT, Inc. will also need to adopt significant and costly information technology system changes to comply with the Rule.

91. Development and approval of a new market rule or an amendment to an existing market rule typically takes 5 to 12 months on a normal timeline or 2 to 4 months on an urgent timeline. Market rule changes may require changes to ERCOT, Inc. and market participant systems. Implementation of any necessary system changes resulting from a rule change typically takes an additional 9 to 18 months on a normal timeline or 8 to 12 months on an urgent timeline. However, depending on the complexity of the change, the timelines for both rule development and system implementation can vary. The above-discussed timelines do not include market participant appeals of protocol changes to the PUCT, which is permitted under PUCT rules. The appeal to the PUCT of a protocol adopted by ERCOT, Inc. can take anywhere from 5 to 15 months, depending on the complexity of the protocol that is being challenged. The above-discussed timelines also do not include the appeal of a PUCT decision in court, which can take several years.

92. Since compliance with the Rule will likely require substantial changes to ERCOT, Inc. market rules, development and approval of the rule changes and implementation of the necessary system changes will likely take a minimum of 14 months and could take significantly longer. These changes will be irreversible.

93. In sum, EPA has vastly underestimated the regulatory and electricity system changes needed to comply with the mandates of the Rule. Even if Texas begins implementing these changes immediately, there will not be enough time to thoughtfully determine the feasibility of these changes in time for the submission of a State Plan in either September 2016 or September 2018. The Rule requires Texas to fundamentally overhaul laws and regulations governing electricity in the State, and it mandates hasty changes to the ways Texas generates, transmits, and consumes electricity. Absent a stay, Texas will have no choice but to immediately undertake actions that will cause harm to its citizens and sovereignty. These harms will be permanent and irreversible, and they can be easily prevented with a stay pending litigation.

94. I declare, under penalty of perjury, that the foregoing is true and correct.

Executed on October 19, 2015.

Brian H. Lloyd

Brian H. Lloyd

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos.________

DECLARATION OF JIM MACY, DIRECTOR, NEBRASKA DEPARTMENT OF ENVIRONMENTAL QUALITY

I, Jim Macy, declare as follows:

1. I am the Director at the Nebraska Department of Environmental Quality ("NDEQ"). I have over 30 years of experience in the environmental field as a regulatory official in the State of Missouri, as a consultant, and now as the head of the State of Nebraska's environmental agency. As part of my duties, I am responsible for overseeing and supervising the agency in Nebraska with exclusive jurisdiction to act as the state air pollution control agency for all purposes of the Clean Air Act, as amended, 42 U.S.C. 7401 et seq., including development and administration of State Plans under Section 111(d) of the Clean Air Act. I have personal knowledge and experience to understand what steps that Nebraska has taken and will need to undertake in response to the EPA's final Section 111(d)

Rule: Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.

2. Based on my experience, I have determined that implementing the final Section 111(d) Rule will be a complicated and time-consuming endeavor. Without prior notice and an opportunity for the State to comment, EPA decided to make Nebraska's CO_2 emissions goal significantly more stringent in the final 111(d) Rule than it was in the draft 111(d) Rule. These changes will make Nebraska's task even more difficult.

3. The final Section 111(d) Rule is unlike any other Clean Air Act implementation undertaken by Nebraska. Specifically, the final Section 111(d) Rule's reliance on measures that require the reduction of demand for a particular source of energy—building blocks 2 and 3—are unprecedented for Nebraska and the NDEQ. Nebraska will be required to expend a large number of resources to design a State Plan that incorporates these building blocks.

4. NDEQ employees have already expended approximately 2000 hours on interpreting and preparing for the implementation of the final Section 111(d). During the proposal stage, the NDEQ reviewed the proposal, held multiple meetings with the affected utilities to understand potential impacts, met with the affected utilities in groups and individually, met with the Southwest Power Pool to understand how the final 111(d) rule would impact transmission, convened

discussions with industry and other interest groups, met with the Nebraska Energy Office, met with the Nebraska Power Review Board, participated in conference calls with EPA and other states to clarify understanding of the proposed rule, analyzed the proposal, and prepared comments.

5. Planning, designing, and implementing a State Plan to comply with the final Section 111(d) Rule will require substantial state resources. The NDEQ will need to partner with the Nebraska Energy Office and the Nebraska Power Review Board to implement the final Rule. This partnership will be unprecedented in Nebraska. The final 111(d) Rule requires that a State Plan be developed in a manner that goes through a public comment and public hearing process, which we anticipate could take as long as six months. The final Section 111(d) Rule gives Nebraska until September 6, 2016, to submit its State Plan. Extensions are available for two years for an individual state. Preparing and submitting a timely plan may require three dedicated staff members, additional contractors to facilitate meetings with stakeholders state-wide, and significant resources from other state agencies, stakeholders, and the Nebraska Legislature. There will inevitably be additional or redirected costs of implementation so it is difficult to estimate the total cost at this time.

5. If Nebraska chooses to adopt a multi-state approach to complying with the final Section 111(d) Rule, Nebraska will need to enter into either a

memorandum of understanding or agreement with the other States. Nebraska has experience in negotiating this type of agreement with other States, and it is anticipated that a significant amount of time will be required to negotiate and reach consensus on the content of such an agreement with other States.

6. The final 111(d) Rule may also require changes in Nebraska laws, which would require action by the Nebraska Legislature. The timetable for legislative changes is unknown.

7. Implementing a State Plan under the final 111(d) Rule will consume vital state resources, which would otherwise be devoted to addressing pressing issues of public concern.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Executed on October 16th, 2015.

Jim Macy
Director, Nebraska Department of
Environmental Quality

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ______

DECLARATION OF NEW JERSEY
DEPARTMENT OF ENVIRONMENTAL PROTECTION

I, Bob Martin, declare as follows:

1. I am the Commissioner of the New Jersey Department of Environmental Protection (DEP).

2. I have a Bachelor of Economics degree from Boston College and a Master of Business Administration degree from the George Washington

University. I have served as DEP's Commissioner since January 2010. During that time I have overseen air pollution control rule development, permitting, and management of New Jersey's air pollution control program.

3. Prior to my appointment as Commissioner, I spent more than 25 years in the private sector, during which time I worked with large utility and energy companies in the United States, Canada, the United Kingdom, and throughout Europe.

4. Based on my position and experience, I have the personal knowledge to understand the steps NJ will need to take in the future to comply with the requirements of EPA's Section 111(d) Rule (the Rule), including the submission of a State Plan to EPA, which is necessary to implement the Rule.

5. To comply with EPA's Section 111(d) Rule and meet the September 6, 2018 deadline for final plan submittal to EPA, DEP must immediately begin developing a State Plan. There can be no delay while this matter is pending in the Court, otherwise NJ would find itself in violation of the Rule if it were to be upheld by the Court.

6. According to EPA, emissions credit trading is an important and cost-effective compliance option that states should consider when developing their State Plans. However, EPA has not yet finalized its model trading rules, and is not expected to finalize them until the third quarter of 2016. As a result of EPA's incomplete

regulatory regime for trading as of publication of the Rule, NJ will be unable to properly consider whether emission trading is even a viable option for NJ.

7. By the time EPA's model trading rules are expected to be finalized, NJ will only have two years to submit its final State Plan. Based upon NJ's experience and well-established past practice with EPA, two years is not sufficient time to accomplish the scientific, technical and regulatory work that is necessary to complete a final State Plan, such as power use and source evaluations and options modeling as more fully described below. Absent a stay, NJ will be forced to either develop a State Plan based on incomplete information, which could lead to economically inefficient and potentially arbitrary policy choices, or risk abdicating NJ's sovereignty to EPA through the imposition of a federal plan, which the Rule will impose on NJ if a State Plan is not submitted.

8. Based on my knowledge and experience, I have determined that implementing EPA's section 111(d) Rule at the State level will be extremely complex, time-consuming and costly. I believe it will require an implementation effort that exceeds all others previously undertaken by DEP under the Clean Air Act. NJ will be required to:

- develop as complete an understanding of the Rule as possible, under circumstances where many substantive issues cannot be resolved because the Rule is incomplete and not comprehensible;

- comment on the proposed federal plan and proposed model emission trading rules;
- evaluate the approximately 30 options for State Plan paths included in the Rule and EPA's proposed 111(d) rules;
- reevaluate these options when the model trading rules are adopted by EPA (scheduled for adoption in the third quarter of 2016);
- select potentially viable options for more detailed consideration by the State;
- consult with other states to determine if there are potential interstate trading partners that might provide mutual benefit;
- consult with stakeholders in NJ;
- consult with the operators of the PJM electric grid (which includes NJ) on electric reliability implications of the options under consideration,
- consult with load serving entities and generators;
- consult with the NJ Division of Rate Counsel;
- reevaluate potentially viable options for NJ with the input of PJM and NJ stakeholders;
- conduct detailed dispatch modeling and macroeconomic analyses of NJ's options;
- select the most viable option for NJ;
- determine if new legislation is needed and seek that legislation;
- determine what regulatory adoptions are needed;
- commence an estimated 24-month rule drafting, proposal and adoption process (possibly longer given the complexity and uncertainties of EPA's rules);

- create an organizational structure to implement NJ's State Plan; and
- determine the staffing needed to implement and enforce the State Plan and secure that staffing.

9. Implementation of the Rule is even more complicated and time consuming than usual because major legislative and regulatory changes must be pursued with the New Jersey Board of Public Utilities (BPU). The coordination of these necessary legislative and regulatory changes by multiple areas of State government requires much more effort than independent regulatory actions by these State agencies. This required coordination affects and extends the timeframes to complete the evaluation of EPA's final rules, the selection of a compliance path, and the legislative and regulatory process to follow that path. This will require significant staffing, the ultimate level of which is unknown until EPA's model rules are finalized, understood and staffing needs determined.

10. As noted above, EPA's proposed model trading rule offers an example of the challenge posed to States by EPA's complicated and incomplete regulatory regime under Section 111(d). The Rule discusses emissions trading as an important and potentially cost-effective compliance option for states' 111(d) plans. EPA has proposed two "trading ready" programs as part of the Rule. However, these proposed rules are not even complete and contain numerous substantive components that are subject to change until EPA adopts its trading provisions. Also, EPA's proposed

"trading ready" model trading rules for rate-based states include a number of technologies that have limited or no practical viability in NJ during the compliance period (new nuclear capacity, nuclear uprates, geothermal, utility scale hydro). Additionally, it appears that to effectively use trading, NJ will need to develop a customized trading rule that includes offshore wind, landfill gas recovery and power production, and other potential renewable energy components that may become viable and cost effective in NJ. However, NJ is forced to wait for EPA to finalize its trading rules before it can even consider customizing a trading program to use in its State Plan.

11. While NJ must wait for EPA to finalize its trading rules, it does not receive a corresponding extension for developing a State Plan. This condensed period could force NJ to develop a State Plan that does not fully reflect all of NJ's ultimate policy objectives, thus infringing on NJ's sovereignty. This condensed period would also force NJ to develop a State Plan that is less cost effective than if NJ had the opportunity to fully evaluate and include all options for trading. Further, this shortened period may deprive NJ of the time needed to coordinate with other states and achieve the potential efficiencies associated with interstate trading. Overall, this condensed period may result in the development of a State Plan which does not incorporate the legitimate and critical policy considerations inherent in New Jersey's

authority to govern in the best interests of its citizens, the environment, and its economy.

12. Developing a State Plan will be further complicated by the fact that NJ will not be able to comply with its emission limit by directly regulating the emissions from affected Electric Generating Units (EGUs), which previously had been the conventional, legal means by which EPA and the states have regulated emissions from source categories under Section 111 of the Clean Air Act . Under the Rule, EPA has assigned to NJ a target emission rate that is well below the technologically feasible emission rate for existing fossil-fuel fired EGUs. As a result of EPA's unattainable target emission rate for existing EGUs, NJ will be forced to regulate "outside the fence" of affected EGUs in order to comply with the Rule, i.e. regulate activities beyond the affected EGUs' physical boundaries. The Rule's requirement that NJ regulate "outside the fence" of affected EGUs is an unprecedented regulatory approach under Section 111 of the Clean Air Act.

13. EPA's stringent emission limits for existing EGUs will produce immediate and unexpected harms to affected EGU owners, NJ ratepayers and the business economy. As a result of the Rule, existing EGUs will be at a disadvantage compared to new sources because both existing and new combined cycle natural gas units will meet the 111(b) standards with relative ease but only the existing EGUs will need to purchase allowances or emission reduction credits (ERCs). Congress

instructed EPA to be conscious of the remaining useful life of existing sources under Section 111(d), not put existing sources at a competitive disadvantage. The costs of compliance will be shifted to businesses and ratepayers in the form of higher energy costs. Importantly for the stay application, many of these costs will be incurred during the time that this matter is pending in the Court if a stay is not issued.

14. Furthermore, while EPA claims that states have many options to comply with the Rule, most of the options referenced by EPA are simply not available to NJ. This is because many of EPA's proposed compliance options already have been fully utilized in NJ. NJ's early efforts in supporting clean energy are not eligible for credit under the Rule because EPA chose to credit only those actions taken after the 2012 baseline year that EPA arbitrarily set, effectively penalizing NJ for being a leader in this field.

15. NJ already has invested approximately $3.27 billion in ratepayer funds to advance solar development and energy efficiency initiatives before 2013. These investments and their attributes are rejected by EPA for compliance credit under the Rule even though these investments will continue to produce clean energy and energy savings well into the compliance period of the Rule. I believe that EPA's rejection of these investments for compliance credit will have the effect of stranding these assets because otherwise identical post-2012 facilities will be favored because they will provide credit towards compliance with the Rule. Until EPA finalizes its proposed

model trading rules, the impact on NJ's ratepayers and developers of pre-2013 solar energy and energy projects is difficult to ascertain, although the impact will most likely be measured in billions of dollars of stranded investments, i.e, investments that would otherwise have a higher value in the market but will be compromised due to the Rule's preference for newer investments. And once these investments are lost or withheld, they cannot be recovered without lingering, irreparable damage to NJ's economy.

16. The energy industry in the State of New Jersey must begin making decisions that will affect energy prices based on this final regulation, attempting to find certainty in this incomplete regulatory regime. Therefore, New Jersey's electricity distribution companies will be impacted in numerous ways especially with regard to the fact that the price of their products will be higher than it would have been without the regulations. EPA estimated in its Regulatory Impact Analysis that annual compliance costs will be $5-$8 billion. But Fitch Ratings company, citing various sources, states that average annual compliance will be $28 billion.[1] Higher electricity prices significantly impact residential customers, particularly low-income customers who spend a higher percentage of their income on energy. Spending more on energy

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[1] Pidherny, D., Greene, R., Sonola, O., & Bains, R. (January 30, 2015). *The Carbon Effect: Assessing the Challenges for Public Power, Special Report.* Fitch Ratings, Inc.

will reduce the resources they have available to purchase other goods and services thereby lowering their standard of living.

17. In commercial and industrial markets, higher electricity prices reduce profitability, creating disincentives for investment and job growth. Given that New Jersey already has some of the highest electricity prices in the nation caused in part by its already aggressive response to environmental concerns, further increases are likely to have deleterious employment impacts, and that high electricity prices are one reason for the continuing decline in the manufacturing base in New Jersey. Most manufacturers compete in a global marketplace and cannot absorb higher electricity prices.

18. The U.S. Chamber of Commerce estimates the Rule will decrease GDP by $51 billion annually, leading to an average of 224,000 fewer jobs each year, causing a cumulative loss of $586 billion in income by 2030.[2] States like New Jersey, with already high energy costs, will suffer proportionally more of these job losses.

19. To summarize, the Rule creates a "Catch 22" for NJ in light of EPA's incomplete trading rules and unattainable emission targets. State Plan deadlines are included in the Rule, but the rules governing trading under the Rule are not and will not be final until late 2016, leaving states to decide whether to wait for final trading

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[2] U.S. Chamber of Commerce's Institute for 21st Century Energy. (2014) *Assessing the Impact of Potential New Carbon Regulations in the United States*.

rules or begin developing a plan that may be inefficient and more costly to ratepayers. This dilemma is compounded by the numerous options for compliance, most of which are dependent on the finalization of the model trading rules in order to reasonably evaluate their implementation feasibility and costs. EPA's approach effectively eliminates options that may be most cost effective for NJ, could cause irreparable harm to the economy of the State, and could infringe on NJ's sovereignty if EPA were to impose a plan on NJ.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct. Executed on this twenty-second day of October, 2015, at Trenton, New Jersey.

Bob Martin, Commissioner

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos.

DECLARATION OF JEFF MCCLANAHAN

I, Jeff McClanahan, hereby declare as follows:

1. I am the Director of the Utilities Division of the Kansas Corporation Commission (KCC). The KCC regulates public utilities, common carriers, motor carriers, and oil and gas producers. Public utilities include local telephone, natural gas, and investor-owned electric service providers. As part of its duties, the KCC is responsible for ensuring that reliable and affordable energy is available and deliverable to Kansas citizens and businesses.

2. Based on my position, I have the personal knowledge and experience to understand what steps the State will need to undertake in response to the Environmental Protection Agency's (EPA's) Section 111(d) Rule, including the difficulties that will be encountered in attempting to comply with the Rule. In general, the Section 111(d) Rule will dramatically transform the way electric power will be generated, dispatched, and transmitted to consumers in the State of Kansas and throughout the United States.

3. Based on my work experience and position, I have determined that implementing the Section 111(d) Rule will be a complicated, time consuming, and expensive endeavor, which will require the expenditure of substantial State resources, immediately and over the next several years.

4. Kansas will need at least three years to conclude a stakeholder process to determine the least cost state plan which ensures electric reliability. This process will require:

a. Defining the options for compliance and evaluating these options in terms of least cost and reliability

b. The evaluation of these options will need to be done on an expanding geographical basis, beginning with the individual EGUs, then the individual utilities, next at a state level, and finally at a multi-state level. At each stage, the options will need to be tested using sophisticated dispatch models with varying assumption about fuel costs, O&M costs, potential carbon prices, population and economic growth in Kansas and its surrounding states, different infrastructure developments including electric generation, transmission, and distribution investments, and natural gas infrastructure investment, to safeguard that only robust options are considered. And finally, the options must be evaluated on both a Kansas only state plan and on a multi-state implementation plan.

c. The evaluation process will require the KCC to work with all the stakeholders to ensure that all of the feasible options are evaluated. Thus, the process will require the KCC, utilities, the Kansas Department of Health and Environment (KDHE), the Southwest Power Pool, and other affected groups to work together in a careful and efficient manner. This process will require expenditures on costly resources and entail several years of intensive study, consultation, and negotiation.

d. Once the Commission, KDHE, and the State Legislature have agreed on a plan for its jurisdictional utilities, KDHE must develop a compliance plan or plans for each of the utilities.

5. Based on my knowledge and experience, the Section 111(d) Rule represents an unprecedented infringement by the EPA on the traditional authority of Kansas to manage energy resources within our jurisdiction because the mandates of the Section 111(d) require KCC to undertake specific changes to how energy is generated, dispatched, and transmitted to consumers. The Section 111(d) Rule also disrupts the well-settled division of authority over electricity markets under the Federal Power Act, and raises significant uncertainty about the role of the Federal Energy Regulatory Commission (FERC) to ensure the reliability of electricity through the wholesale market. In determining the adequacy and reliability of its system, a state must balance various public interest concerns and technical considerations to maintain sufficient and efficient service at just and reasonable rates. The overarching technical and policy concern in this area is the appropriate generation mix to be employed by jurisdictional utilities. The Section 111(d) Rule severely invades a state's authority to make such determinations.

6. Absent a stay from this Court, compliance planning must begin immediately. The system-wide changes necessary for compliance must be gradual to preserve reliability of the electric grid. Because compliance is calculated based on a moving average, the longer Kansas waits to begin compliance, the more expensive and difficult it will be to meet the requirements of the Rule. In addition, the KCC estimates it will spend approximately $500,000 to $1,000,000 on consultants to aid in the analysis and development of a compliance plan. Any potential changes to EPA's Section 111(d) Rule resulting from court decisions, which will most likely take several

years to decide, will require additional analysis and modification of the initial plan developed in Kansas. This will result in significant additional costs and a waste of the State's resources.

7. Absent a stay from this Court, evaluation of specific compliance measures, such as new facilities or retirements, must also begin immediately. The lengthy application and approval process for utilities to construct, upgrade, or retire generation, transmission, and distribution facilities to comply with the Section 111(d) Rule, as well as the in-depth evaluation of public necessity and convenience for each facility, requires utilities to plan and submit applications for upgrades almost immediately after publication of the final Section 111(d) Rule in order to have equipment constructed, upgraded, or decommissioned before the compliance period begins in 2022.

8. Kansas will need to request an extension until 2018 in order to develop a reliable compliance plan at the lowest cost. EPA will then need six months to a year to approve the Kansas plan, resulting in a final approved plan in 2019. Given the three years (2019 to 2022) EPA is allowing for Kansas to construct or upgrade facilities with long construction times – five to seven years for transmission assets – the interim goals beginning in 2022 are unachievable. Further, the KCC expects billions in ratepayer costs to comply with this rule. Absent a stay from this court, Kansas utilities are at risk of investing money to comply with a plan under pending review. If the rule is not upheld, ratepayers will be obligated to pay for those initial investments plus any investments made to comply with a modified rule. Immediate compliance has the potential to be a significant and unnecessary waste of state and ratepayer funds.

9. Kansas stakeholders are currently meeting on a weekly basis to evaluate compliance options due to the unrealistic compliance deadlines set in the Section 111(d) Rule. The work being performed by all stakeholders includes analysis of the requirements in the Section 111(d)

Rule, development of timelines and due dates, evaluation of compliance options, estimation of compliance costs, and determination of risk regarding reliability of the bulk electric system for each option. Given the large number of stakeholders affected, hundreds of hours of time are being expended each week. The stakeholder efforts result in a significant cost of human resources and expense on a weekly basis, all in the hope of meeting unrealistic compliance deadlines.

10. In excess of $3 billion has been spent by Kansas utilities on environmental compliance projects for its coal-fired generation fleet, and these projects were approved by the EPA under state implementation plans (SIPs). The Section 111(d) Rule creates stranded utility/ratepayer investment because coal-fired units that were retrofit in compliance with EPA rules have not been excluded from the calculations in determining a CO_2 emissions goal. It is inherently unfair and extremely poor regulatory policy to require significant expenditures to reduce coal plant emissions and then change the regulatory paradigm to eliminate or significantly curtail coal-fired generation without regard to the useful remaining life of those Electric Generating Units (EGUs).

11. Decisions made for the sake of compliance with the Section 111(d) Rule immediately and over the next several years will be irreversible and will impact the electric grid for decades. System planning is typically based upon the 30-40 year expected lives of generation and transmission facilities. The decision to prematurely retire an electric generating unit could significantly impact system reliability and may unnecessarily increase customer's rates for decades to come.

12. The Section 111(d) Rule sets an emissions performance standard for the State of Kansas, rather than the specific affected EGUs. By doing so, the EPA has created a near

certainty that legally-troublesome cross-subsidies will occur between ratepayers of the various utilities in the state. The KCC can address cross-subsidy issues within the context of setting rates for one single utility. However, the EPA's state-wide emissions standard will create cross-subsidy issues between the customers of *separate utilities*. The KCC does not have statutory authority to allocate the costs associated with the Rule to all ratepayers in Kansas because the KCC does not regulate a large number of utilities. Therefore, if a non-jurisdictional utility does not agree to a compliance plan, the KCC would be forced to require jurisdictional utilities to take additional measures to meet the overall emissions guideline. This results in KCC jurisdictional ratepayers subsidizing the costs of compliance for non-jurisdictional ratepayers.

13. Kansas law (K.S.A. 66-104 and 66-104d) currently exempts the majority of municipal and cooperative utilities from regulation by the KCC. Because Kansas' state plan must be federally enforceable, it is possible that the deregulated municipal and cooperatives affected by the Section 111(d) Rule will need to become regulated again. Any change of state law and policy due to a federal mandate is difficult and uncertain and should not be undertaken unless all possible appeals have been addressed and the rule has become final post-litigation.

14. Absent a stay from this Court, if Kansas chooses to adopt a multi-state approach to comply with the Section 111(d) Rule, changes to rights and responsibilities of entities such as Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs") will be immediate and long lasting. If Kansas joins in a multi-state compliance approach, it is likely to take the form of credit trading or an induced carbon price through the RTO. The members of these organizations must follow a prescribed stakeholder process to effect the changes, and Kansas must agree to grant certain enforcement powers to those organizations. This will likely require a revision of K.S.A. 65-3031, which otherwise prohibits such changes. The

stakeholder process and any necessary institutional changes for the states included in the multi-state approach, the RTOs, and ISOs will need to be completed before a plan relying on those third parties can be submitted for approval to the EPA. Utilities require certainty of cost recovery when planning for large-scale infrastructure investments that have a useful life of 40 years or more. Adding institutional uncertainty to the already created increased price and investment uncertainty will make utility compliance even more problematic and could place affected utilities in an untenable position. These processes are lengthy, difficult to reverse once established, and will require immediate expenditure of resources over next calendar year.

I declare under penalty of perjury that the foregoing is correct. Executed on this 14TH day of OCTOBER, at Topeka, Kansas.

Jeff McClanahan

Jeff McClanahan

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos.

DECLARATION OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

I, Richard S. Mroz, declare as follows:

1. I am the President of the New Jersey Board of Public Utilities (BPU). The BPU is the agency empowered by the laws of the State of New Jersey with authority over regulated utilities to ensure that New Jersey ratepayers receive safe, adequate, and proper service at just and reasonable rates. The BPU also has authority, as the State Energy Office, over the administration of federally funded energy programs for the State. As President of the BPU, I serve as the BPU's presiding and chief administrative officer as well as a cabinet member in New Jersey. I also act as

the chairperson for the State's Energy Master Plan (EMP) Committee. The EMP is the State's strategic plan for the use, management, and development of energy. One of the overarching goals of the EMP is to drive down the cost of energy for all New Jersey ratepayers.

2. Based on my position and experience, I have the personal knowledge to understand the potential impacts of EPA's Section 111(d) Rule (Rule) on energy markets in New Jersey, including its likely impact on ratepayers and the broader State economy.

3. Absent a stay, to implement the Rule, New Jersey needs to develop its State plan immediately. This will require the State of New Jersey to make several significant legislative and regulatory changes to implement the actions necessary for compliance with the Rule. The decisions that New Jersey is forced to make now will influence the energy grid in New Jersey and influence the behavior of energy producers, transmitters, and consumers for the foreseeable future. Those impacts will be immediate, and will be impossible to undo if the Rule is later invalidated unless a stay is issued now.

4. In 1999, New Jersey deregulated its energy regulatory structure, limiting the BPU's jurisdiction to the regulation of electric and gas distribution companies. As a result, the BPU no longer exercises authority over electric generation facilities.

a. Implementation of the Rule could require the construction of new power plants to achieve compliance. If that is the case, New Jersey would need to enact new legislation to vest the BPU with the authority to direct that construction.

b. Implementation of the Rule requires authority to direct the actions of existing generators to achieve compliance. The BPU does not currently have this authority. The Legislature would have to grant the BPU this additional authority by new law.

c. Implementation of the Rule requires electric generating units to enter into purchase power agreements or contracts. The BPU also lacks the authority to require these under New Jersey's current legislative scheme. Thus, it is impossible for New Jersey to implement the Rule absent new legislation.

5. The Rule provides for a trading program that includes energy efficiency. Under the existing legislative scheme, the BPU lacks the authority to develop such a program. New Jersey's Legislature would need to enact new legislation. In addition, the BPU would need to draft, propose, and adopt new regulations to implement such a trading program.

6. Implementation of the Rule would also require amendments to New Jersey's existing statutes and regulations governing its renewable portfolio standard.

For instance, New Jersey's legislation and accompanying regulations define renewable energy certificates and solar renewable energy certificates. A renewable energy or solar renewable energy certificate represents all of the environmental benefits or attributes of one megawatt hour of generation from either a Class I or Class II renewable energy or solar energy facility. By contrast, the Rule provides for an emission reduction credit for only CO2, which is but one of the environmental benefits in the New Jersey renewable energy or solar renewable energy certificate. Therefore, New Jersey's statutes and regulations would need to be revised because the same megawatt hour could not satisfy both requirements. This process would require action by the Legislature as well as subsequent action by the BPU to draft, propose, and adopt new regulations.

7. New Jersey is a member of PJM Interconnection, LLC (PJM), the federally-authorized regional transmission organization (RTO) responsible for operating and managing competitive wholesale electricity markets and the interstate transmission system within the 13-state (plus the District of Columbia) regional electric power grid. PJM's operational objective is the insurance of electric system reliability. PJM is under the exclusive jurisdiction of the Federal Energy Regulatory Commission (FERC).

a. Under the Rule, states have the option to enter into agreements among themselves without regard for a state's particular RTO or accounting for

FERC's authority over the RTO. This creates uncertainty and jurisdictional conflicts between the states' authority and that of FERC, likely leading to implementation delays or more that would make immediate compliance impossible.

b. In addition, implementation of energy efficiency measures related to the electric transmission system that may be necessary to achieve compliance with the Rule may be exclusively regulated by FERC and under the operational control of PJM, which has the obligation of ensuring the reliability of the electricity grid. Without new legislation, the BPU cannot immediately order the implementation of such measures to ensure compliance with the Rule.

8. Implementation of the Rule will irreparably harm New Jersey's ratepayers, who have funded and continue to fund investments directed by PJM, FERC, and the BPU, and who will be obligated to make additional investments to comply with the Rule. If no stay is granted and the Rule is later invalidated, New Jersey's ratepayers will bear the cost of implementing the Rule with no concomitant benefit and no mechanism to refund investments made toward compliance with the invalidated rule.

a. PJM determines transmission system upgrades necessary to ensure continued electric system reliability; PJM-identified transmission upgrades, along with the cost allocation of such upgrades, are subject to FERC approval. FERC-approved transmission costs are, in turn, reflected in the price of electricity borne by New Jersey's ratepayers. If certain electric transmission system upgrades are later deemed unnecessary for compliance with the Rule, and these upgrades do not receive credit under the Rule, New Jersey ratepayers will still be forced to pay for the costs associated with the construction of those transmission system upgrades, in addition to any new construction that may be required under the Rule, with no economic recourse.

b. From 2001 to 2012, $3.27 billion was invested in renewable energy and energy efficiency in New Jersey, the costs of which were borne by New Jersey's ratepayers. The Rule in its current form disallows credit for renewable energy sources and increases in nuclear power plant capacity developed before 2013, effectively penalizing New Jersey for its leadership in this area. New Jersey's ratepayers will be irreparably harmed because they will not receive financial benefit for their investments in energy efficiency and renewable energy.

9. New Jersey's ratepayers are already saddled with electricity prices that are among the highest in the nation. EPA has acknowledged that implementation of

the Rule will initially increase these electricity prices. Without a stay, New Jersey's efforts to comply with the Rule will harm the State's economy.

a. Higher electricity prices will significantly impact New Jersey's ratepayers, particularly low income ratepayers, by reducing the resources they have available to purchase other goods and services, thereby lowering their standard of living.

b. Higher electricity prices will negatively impact the New Jersey economy by reducing profitability for investment and job growth and will lead to a decline in New Jersey's energy-intensive manufacturing and commercial services sectors, with significant attendant job losses.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Executed this 16th day of October, 2015.

Richard S. Mroz, President
New Jersey Board of Public Utilities

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ______

DECLARATION OF ELLEN NOWAK, CHAIR, WISCONSIN PUBLIC SERVICE COMMISSION

I, Ellen Nowak, declare as follows:

1. I am the Chair of the Public Service Commission of Wisconsin ("PSCW"). I have been employed at the PSCW for four years. As part of my duties, I have authority to monitor, track, and interact with stakeholders[1] and

[1] Stakeholders include regulated utilities, merchant-owned EGUs, municipal utilities, utility cooperatives, environmental groups, industry groups, residential and small business representatives, Midcontinent Independent System Operator, Inc. ("MISO"), Midwest Renewable Energy Tracking System ("M-RETS"), and representatives from other entities interested in or impacted by state and federal environmental rules impacting public utilities.

regulators on the development and implementation of state and federal environmental rules impacting public utilities.

2. Immediately after the release of EPA's proposed *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units*, 79 Fed. Reg. 34, 830 (June 18, 2014) ("Proposed 111(d) Rule"), the PSCW acted to determine what steps Wisconsin would need to take in response. The PSCW's review determined that, in general, the Proposed 111(d) Rule would dramatically transform the way electric power would be generated and transmitted to consumers in Wisconsin and throughout the United States. The Proposed 111(d) Rule would, at the very least, require the construction of new power plants and associated infrastructure, the updating or decommissioning of existing power plants that are not fully depreciated, and the reduction in overall energy consumption by every single current and future consumer of electric power. In short, the Proposed 111(d) Rule would transform the American economy.

3. Based on my work experience and position, I have determined that implementing the Proposed 111(d) Rule would be a complicated, time consuming, and expensive endeavor, which would require the expenditure of substantial State resources, immediately and over the next calendar year. The final version of the Proposed 111(d) Rule ("Final Rule") was released on August 4, 2015 and is expected to be published in the Federal Register in mid to late October, 2015.

Though the Final Rule is different than the proposal, it will not reduce the amount of resources necessary for planning and implementation in the immediate future.

4. Significant PSCW resources have already been invested to understand and evaluate the Proposed and Final 111(d) Rule. PSCW employees have spent significant time understanding the proposal and preparing for implementation, including outreach to all Wisconsin stakeholders, organizing stakeholder meetings and listening sessions, participating in regional collaboratives such as Midcontinent States Environmental and Energy Regulators and the Midwest Power Sector Collaborative with other states and industry participants, attending EPA listening sessions and conference calls, and in-depth analysis of the impact of the 111(d) Rule on the state and regional systems.

5. In order to help inform our comments on the Proposed 111(d) Rule, and to determine the viability of a regional plan when compared to a state plan, the PSCW expended substantial resources modeling likely compliance scenarios. The purpose of this model was to forecast the cost of the changes in the Wisconsin utility market that would be necessary to comply with the Proposed 111(d) Rule. With input from stakeholders, engineers from the PSCW collaborated with MISO to build a model using the "Electric Generation Expansion Analysis System ("EGEAS"). Several model runs were completed, analyzed, and presented with

our comments to the EPA. We also presented the modeling results in several different conferences with Wisconsin stakeholders.

6. The PSCW has begun its comprehensive review of the Final Rule and its effects on everyone who pays an electric bill in Wisconsin. The Final Rule is significantly different, which means, absent a stay, PSCW staff must undertake another intensive investigation into the requirements of the Final Rule and start over with evaluation of compliance paths and modeling. Similarly, if litigation changes the Final Rule, much of the time and energy invested in understanding and compliance planning for the Final Rule will have been wasted. Wisconsin will be forced to choose between following through with compliance of the un-altered Final Rule, or starting over with a third investigation and compliance analysis.

7. Based on my knowledge and experience in analyzing the Proposed and Final 111(d) Rules, the Final Rule represents an intrusion by the EPA on the traditional authority of Wisconsin to manage energy resources within our jurisdiction. The Final Rule also raises uncertainty about the role of the Federal Energy Regulatory Commission to ensure the reliability of electricity through the wholesale market. Without clarity on the roles of different state and federal agencies, the PSCW is at risk of violating any number of rules, order, and mandates. The Final Rule should be stayed until these jurisdictional questions are fully adjudicated.

8. Absent a stay from this Court, Wisconsin will continue to invest resources in compliance planning. Evaluation of compliance options has already begun. The system-wide changes necessary for compliance will require collaboration among other state agencies, stakeholders and other states, and resulting compliance measures must be implemented gradually to preserve reliability of the electric grid. Because there are interim limits that must be achieved, the longer Wisconsin waits to begin planning, the more expensive and difficult it will be to meet the requirements of the Final Rule.

9. Absent a stay from this court, significant resources may be wasted on continued evaluation of specific compliance measures, such as the construction of new facilities or retirements of existing facilities. In order to have facilities constructed, upgraded, or decommissioned before the compliance period begins in 2022, the lengthy application, in-depth evaluation, and approval process for utilities to construct, upgrade, or retire facilities to comply with the Final Rule requires utilities to plan and submit applications very soon after publication of the Final Rule, and even before an EPA-approved State or Multi-State plan.

10. For example, the Final Rule will likely require one or more new natural gas plants in Wisconsin. A new natural gas combined cycle plant takes at least five years from application to operations. Before submitting an application for a new generation resource that requires a certificate of public convenience and

necessity (CPCN) from the PSCW pursuant to Wis. Stat. § 196.491(3), a utility conducts a needs assessment, site selection, and pre-engineering work. This work can take more than a year to complete. In addition, the utility works with the transmission owner and the Regional Transmission Operator, MISO, to get in the generator queue. Then, the utility submits an application for a CPCN, including full environmental review and analysis of need by the PSCW, which requires a contested case hearing. This process can take up to one year to complete. After the CPCN is issued, it takes another three years for final engineering and construction before the plant can go into service. Waiting until litigation is complete to begin implementing the measures required in the plan would make it impossible for Wisconsin to meet the 2022 goal, and even more costly and difficult to meet the final 2030 goal.

11. Ideally, a utility would wait until the state plan was approved by the EPA before planning for future resources, but even if a utility starts planning today, it is possible that the new plant would not be commissioned before the 2022 initial interim deadline. The interim goals will also force utilities to act more quickly than the usual 30 to 40 year planning timeframe, which could preclude building new generation that requires an even longer planning schedule, such as nuclear plants. Even with an extension of time for the interim goal to 2022, if the 2030 goal remains in place during litigation, Wisconsin utilities will have no

choice but to begin implementing compliance measures immediately, subject to the PSCW approval.

12. Not only does commissioning plants include a lengthy approval process, but so does decommissioning plants. Utilities cannot simply shutter a plant's production. Utilities must apply to the MISO for permission to decommission a plant. MISO then evaluates the entire multi-state system for reliability concerns, and can, in fact, decline to allow a plant permission to decommission. MISO has to ensure that enough base load resources are available to fill the void of a decommissioned plant, which may mean importing or constructing new sources. This process lasts at least 26 weeks from application to decommissioning. If Wisconsin's plan is not approved until September of 2019, there may not be enough time before the 2022 interim goal to follow the established retirement procedure. Absent a stay, plants may be prematurely retired, which is difficult, expensive, and in some cases impossible, to reverse.

13. State goals in the Final Rule were calculated based on a significantly higher reliance on natural gas and renewable generation than in the Proposed 111(d) Rule. Compliance with the Final Rule is likely to materially increase the cost of electricity by forcing Wisconsin to move immediately toward reliance on a limited number of fuel sources. There are significant risks associated with this type of system-wide transformation, which is likely to begin occurring in the very

near future, unless the Final Rule is stayed. Wisconsin's electric generation system relies on multiple fuel sources: coal, natural gas, nuclear, biomass, biogas, wind, solar, fuel oil, and international and domestic hydropower. This balanced portfolio approach reduces the risk that electric rates or reliability will be harmed by the price volatility or unavailability of any single fuel source. For example, if the price of natural gas increases sharply, then Wisconsin's system can rely more heavily on other sources, keeping the retail prices stable. The modeling performed by the PSCW on the Proposed 111(d) Rule indicates that in order to comply with Final Rule, utilities will become much more heavily reliant on natural gas as base load generation. This means the overall generation portfolio will be heavily dependent upon one fuel source, creating a high risk for increased system fuel cost as the market for that particular fuel source changes. In other words, if natural gas becomes scarce due to price fluctuations or an interruption in the supply, then generators, and subsequently ratepayers, will experience significant price spikes. The possibility of a significant long-term increase in the price of natural gas due to increased regulation of production methods like fracking could further inflate prices. Given the timelines imposed by the Final Rule, it would be unreasonable for the PSCW to wait until litigation is complete to begin working with utilities on specific compliance measures that move the generation toward heavy reliance on natural gas, which will directly and irreversibly impact the cost of electricity in Wisconsin.

14. The immediate and sweeping changes to the generation fleet could also result in significant decreases in reliability. As noted, PSCW modeling on the Proposed 111(d) Rule showed heavy reliance on natural gas plants in Wisconsin. The output of most renewable sources cannot be easily controlled or dispatched, and is dependent upon the weather conditions. Currently, gas plants that can ramp production up and down very quickly and are used to respond to load variances caused by more intermittent renewable energy resources. For example, if the wind dies or the sun is blocked by clouds, the natural gas plants are used to quickly ramp up energy production to make up for the production loss from the renewable sources, maintaining a balance of supply and demand on the electric grid. Other generation types, such as nuclear and coal facilities, are not able to ramp energy production up and down fast enough to respond to the rapid changes resulting from renewable resources. However, the Final Rule encourages natural gas plants to operate at capacities of 75% or higher, leaving very little capacity that is free to respond to rapid demand changes on the grid. The amount and intensity of these rapid changes will only be exasperated by the increase of renewable resources brought onto the system for 111(d) compliance. The inability to use the natural gas fleet to respond to these rapid supply-demand changes could result in system

overloads, equipment failures, forced shutdown of customer energy supply, and significant reliability concerns. If the Final Rule is not stayed, there will be limited time to study and prevent potential reliability failures. The immediate large scale changes to the electric system required by the Final Rule before 2022 could reduce reliability.

15. In response to concerns about reliability raised by states, generators and FERC, among others, the Final Rule contains a reliability "safety valve" that gives states a 90-day period to exceed carbon limits during emergencies. The eligibility and process for obtaining such relief is cumbersome and time consuming. EPA Air Chief Janet McCabe has publicly stated that approval of such requests for regulatory relief will be a rarity. Thus, the "safety valve" will not be able to address the reliability concerns previously noted regarding the inability to use the natural gas fleet to respond to rapid supply-demand changes caused by more intermittent renewable energy resources.

16. Changes made for the sake of compliance with the Final Rule immediately and over the next calendar year will be irreversible and will impact the electric grid for decades. If system planning begins and capital is committed, and then the Final Rule is invalidated by a court, investors, taxpayers, and ratepayers will all suffer the financial consequences.

17. In addition, implementation of the Final Rule may require legislative changes which could alter the daily operation of utilities. Specifically, the Final Rule allows compliance measures outside of the physical location and control of electric generating units, such as end-use energy efficiency (reduced energy use by electricity consumers), demand response (usage changes according to instantaneous market and load-profile changes), increased distributed generation (such as small residential renewable installations), and increased reliance on renewable generation. For example, a utility can encourage, through financial incentives or otherwise, the use of energy efficiency or demand response, but the utility has no ability to force customers to reduce usage. Parameters for utilities to encourage their customers to rely on these control measures are currently set in state statute. Wis. Stat. § 196.374(3)(b)2 only allows the PSCW to require utilities to spend 1.2 percent of their annual operating revenues on energy efficiency programs. The PSCW does not have authority to force a larger investment in energy efficiency without a statutory change, and will be unable to rely on energy efficiency as a compliance option without these statutory changes.

18. Moreover, higher rates may encourage more customers to install distributed generation on their own property over which the utility has no control. The utility must still provide backup generation to these customers, which will result in a higher cost system. Wisconsin may have to immediately set in motion

the chain of events, including statutory changes, larger investment in customer-side behavior, and further rate restructuring, in order for these compliance options to contribute the amount of carbon reduction EPA expects from them by 2030. This chain of events would be difficult to reverse, and should not begin before there is certainty about the legality of the Final Rule.

19. If Wisconsin joins in a multi-state compliance approach, it's likely to take the form of credit trading or an induced carbon price through the RTO, which will require participation of third party actors, such as the MISO or M-RETS. The members of those organizations must follow a prescribed stakeholder process to effect the changes, and Wisconsin must agree to grant certain enforcement powers to those organizations. The stakeholder process and any necessary institutional changes for entities like MISO and M-RETS will likely need to be completed before a plan relying on those third parties can be submitted for approval to the EPA. These processes are lengthy and may require immediate attention if the Final Rule is not stayed during litigation.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Executed on October 15, 2015

Ellen E Nowak

Ellen Nowak

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA,
STATE OF TEXAS, *et al.*,

Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY,

Respondents.

Case Nos. ________

DECLARATION OF TODD PARFITT

I, Todd Parfitt, hereby declare as follows:

1. I am the Director of the Wyoming Department of Environmental Quality. I received a bachelor of science in natural resources and a master of public administration with an emphasis in environmental policy from The Ohio State University. As part of my duties, I am responsible for overseeing the Department's regulatory programs, including its implementation of federal Clean Air Act regulations.

2. I have been employed by the Wyoming Department of Environmental Quality for twenty-one years. During that time, I have overseen the implementation of numerous facets of the Department's regulatory programs. I have served as

the Director for three years. I also served as Deputy Director for seven years, Administrator of the Industrial Siting Division for seven years, Interim Administrator of the Abandoned Mine Lands Division two different times, and manager of the Department's Clean Water Act pollution discharge permitting program for seven years. I also spent four years working in the Department's Resource Conservation and Recovery Act programs related to hazardous and solid waste and leaking underground storage tanks. In these positions, I regularly reviewed federal and state regulatory program requirements. I also worked with the Wyoming legislature on multiple matters related to the Department's regulatory programs. As a result of my experience, I am well versed in state implementation of environmental regulatory programs.

3. Based on my professional experience, education, and study of the Environmental Protection Agency's ("EPA") finalized but not yet published *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* ("Final Rule"), and supporting technical documents, I have the personal knowledge to understand what steps Wyoming will likely need to undertake in response to the rule, including preparing a state plan. Under the Final Rule, Wyoming must submit a plan, or a request

for an extension request along with an identification of a final approach under consideration and progress made to date, to the EPA by September 6, 2016.

4. Based on my evaluations of the EPA's requirements for Wyoming in the Final Rule, I have determined that implementing the rule presents a complicated endeavor necessitating immediate investment of significant Department resources. This will result in taking resources from other Department programs including Clean Air Act initiatives and commitments. Specifically, creating a plan of the type envisioned under the Final Rule would require years of effort that will be particularly complicated for at least the following reasons.

5. There are significant and substantial changes from the proposed rule to the Final Rule that we have not had time to fully identify or understand at this early stage of Final Rule review. These significant and substantial changes include but are not limited to: a new method for calculating state emission targets, resulting in Wyoming's target goal to change from a 19% reduction to a 44% reduction of CO2 emissions by the year 2030; a substantial change in the methodology in calculating state target rates involving a complicated regional formula not seen by Wyoming prior to the EPA's release of the prepublication version of the Final Rule; and methodology for development

of uniform emission rates for existing Electric Generating Units that are more stringent than emission rates for new Electric Generating Units.

6. The Department is in the process of reviewing the 1560 pages of the pre-publication version of the Final Plan, the 755 page federal plan, and the hundreds of pages of technical supporting documents, which only became available to Wyoming on August 3, 2015. Considering the voluminous nature of these documents and the significant and substantial changes from the proposed rule to the Final Rule, this review process will take staff several months to fully comprehend if and how Wyoming can comply with the Final Rule.

7. The Final Rule relies on "outside the fence" control measures, which include increased utilization of renewable energy and natural gas. Such "controls" are unlike any other Clean Air Act requirement the Department implements. Implementing and enforcing these unusual control measures would require the Department to coordinate with other agencies, including the Wyoming Public Service Commission, which regulates public utilities in Wyoming, and the Wyoming Game and Fish Department, which, along with federal agencies, manage wildlife in Wyoming's renewable energy development corridors. Preparing a plan to meet the requirements of the Final Rule would require considerable collaboration and buy-in to align the differing missions of these

agencies with the EPA's rule. For example, to meet the EPA's goal, utilities in Wyoming would likely have to retire coal-fired power plants. To do that, consultation would have to occur with the Public Service Commission, to evaluate the financial impacts that plant shutdowns would have on electricity consumers under Wyoming's system of public utility regulation. Plant shutdowns would also warrant the Department's consultation with public utility regulators in other states whose citizens pay for Wyoming-generated electricity.

8. Second, and related to the former, the Final Rule requires the construction and operation of new renewable electricity projects to meet the State's goal. Specifically, the Final Rule identifies wind energy and solar energy as the highest potential renewable resources and supposes that nearly tens of thousands of square miles are available to develop these new energy projects. Many of these lands are located within sensitive areas and habitat for certain wildlife, such as greater sage grouse. As a result, developing a plan to generate more wind and/or solar energy consistent with the proposed rule would require intensive coordination with State Game and Fish Agencies, which oversee sage grouse and other sensitive wildlife conservation efforts. Pursuant to Wyoming Executive Order, Wyoming agencies shall "prioritize the maintenance and enhancement of Greater Sage-Grouse habitats and

populations," may authorize new development in core habitat "only when it can be demonstrated to the satisfaction of the permitting agency, and based upon the recommendations made by the Wyoming Game and Fish Department, that the activity will avoid negative impacts to Greater sage-grouse" and must consult with the Game and Fish Department before taking any action that could impact sage grouse. Wyo. Exec. Order 2015-4, at ¶¶ 5, 6 (July 29, 2015). The Order expressly provides that wind energy development "is not recommended in Greater sage-grouse Core Population Areas[.]" *Id.* at Attachment B, p.14. Deploying enough new wind energy to comply with the EPA's proposed Rule also would require consultation and negotiation with the private parties that own the vast majority of the Wyoming lands suitable for wind energy projects. Lines to transmit wind energy generated by those projects will almost certainly have to cross federal lands, thereby implicating the regulatory interests of federal land managers, and requiring compliance with the National Environmental Policy Act. Coordinating these differing regulatory and private interests quickly enough to develop a state plan on the EPA's proposed timeline could only be possible with an immediate re-allocation of a substantial portion of the Department's resources and commitments from federal agencies outside the control of the Department.

9. Wyoming is a net-exporter of energy from both fossil-fuel and renewable sources. Because Wyoming delivers energy to eleven different states, from California to Minnesota, complying with the Final Rule would most likely require Wyoming to enter into one, if not several, multi-state or regional agreements with states that consume power generated in Wyoming. Negotiating and executing those agreements in time to submit a plan on the EPA's timeline would require a significant investment of Department resources. The effort will be complicated by the fact that other states with which Wyoming will likely have to collaborate are located in different EPA regions than Wyoming, which will in turn require plan approvals from different EPA regional offices.

10. Creating a plan that conforms to the Final Rule will require the Wyoming legislature to act. Neither the Department nor any other Wyoming state agency likely has authority to require the unconventional controls on which the EPA's rule relies. For example, the Department does not have the authority to require the construction and utilization of renewable electricity generating projects. Wyoming's legislature meets only once per year and for no more than a total of sixty days every two years, unless the Governor calls for a special session. Wyoming's legislative process typically involves multiple hearings and, therefore, does not produce new law overnight. Even with immediate efforts

from the Department, obtaining the legislative authorization necessary to develop a plan that complies with the EPA's rule on the EPA's proposed timeline will be practically impossible.

11. Developing a plan to comply with the Final Rule will require the Department to recruit new resources, which is further complicated by the recent statewide hiring freeze necessitated by lower than projected revenues. In some cases, the rule implicates subjects outside the Department's normal area of air pollution control expertise, such as reliability of electricity availability and delivery. In other cases, the rule would create significant new workloads, for example, negotiating and administering complex multi-state and regional emissions allocation agreements and facilitating interagency coordination. Hiring new staff implicates the Department's budget, which the legislature must approve every two years, and may, as a result, also require additional legislative action. To prepare a state plan to comply with the Final Rule on the EPA's timeline, the Department would have to make these resource decisions before having had the opportunity to fully review the significant and substantial changes in the Final Rule or having had the opportunity to review and comment on the proposed Federal Plan Requirements.

12. As a practical matter, Wyoming now must begin expending substantial resources in order to attempt to comply with the September 6, 2016 deadline

for state plan submission contained in the Final Rule. This expenditure of resources will need to include consultation with Wyoming energy producers and consumers of Wyoming-produced energy, coordination with multiple states, state agencies and federal land managers, passing new state legislation, promulgating new regulations, and conducting public outreach.

13. Wyoming has already expended resources as a direct result of the proposed and Final Rule. As of October 13, 2015 the Department has dedicated over 1,850 employee hours to evaluating the EPA's proposed and Final Rule and developing ideas on how to craft a compliant state plan. Eight different members of the Department's program-level staff, including more than ten percent of the air quality program employees, have dedicated a total of employee hours working on the EPA's proposed 111(d) Rule since its publication. Those staff were pulled from their normal responsibilities, which include implementing the Department's normal Clean Air Act programs, such as Prevention of Significant Deterioration and Title V. I have personally worked over 400 hours on the proposed rule and Final Rule. In sum, the EPA's proposed rule and Final Rule have already consumed considerable limited Department resources that would otherwise be dedicated to other regulatory efforts. These initial investments of Department resources represent only the tip of the iceberg.

14. Collectively, the Department's efforts have been dedicated to: (1) meeting with the Wyoming Public Service Commission and the electricity generators (2) meeting with Wyoming's elected representatives and other Wyoming regulatory agencies; (3) meeting with regulators from other states, including through the Environmental Council of States, Western Regional Air Partnership, the Western States Air Resources Council, the Air & Waste Management Association, the National Governor's Association, and the Center for New Energy Environment; (4) participating in webinars hosted by the EPA, the Association of Air Pollution Control Agencies, and the National Association of Clean Air Agencies; (5) travelling to and attending the EPA's public hearings on the rule; and (6) researching and evaluating the rule internally. All of these efforts have been necessary to comprehend the bases for the proposed 111(d) rule, the prospects for interstate and regional cooperation, and the feasibility of crafting a Wyoming plan to meet the requirements of the rule.

15. The Department expects to take further steps in the coming months as a direct result of the Final Rule. The Department will continue to confer with the Wyoming Public Service Commission, electricity generators, other state agencies, states that receive electricity produced in Wyoming, and the general public. The Department will also continue to dedicate internal staff resources

to evaluating the practical, technical and economic implications of creating a state plan to meet the requirements of the rule. Those efforts will require continued investments of Department resources that would otherwise support other priorities.

16. If this Court holds that the EPA now lacks authority to regulate power plants under Section 111(d) of the Clean Air Act, Wyoming will immediately halt entirely the above-described expenditures on the Final Rule.

I declare under penalty of perjury that the foregoing is correct. Executed on this 19th day of October, 2015, at Cheyenne, Wyoming.

Todd Parfitt

Todd Parfitt
Director
Wyoming Department of Environmental Quality

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ______

I, Leonard K. Peters, hereby declare as follows:

1. I am the Secretary of the Commonwealth of Kentucky's Energy and Environment Cabinet. I have been employed by the Commonwealth of Kentucky in this capacity for more than seven years. As part of my duties, I am responsible for programs related to the implementation of the provisions of the Clean Air Act.

2. Based on my position, I have the personal knowledge and experience to understand what steps the State will likely need to undertake in response to EPA's proposed final Clean Power Plan, which was released in a prepublication version on August 3, 2015, by EPA ("Clean Power Plan"),

including preparing a state plan consistent with Section 111(d). Under that section, the State must submit an initial plan to the Environmental Protection Agency ("EPA") by September 6, 2016, absent special circumstances.

3. The prepublication version of the Clean Power Plan contains three distinct parts: (a) The final version of the rules for new, modified and reconstructed electric generation sources under Section 111(b); (b) The final version of the rule for existing electric generating sources under Section 111(d); and, (c) The proposed federal plan for implementation in those states which do not submit a state plan or fail to win approval of their plan from EPA.

4. The final version of the rule for new sources under section 111(b) sets a standard for new coal-fired units of 1,400 lbs CO_2/MWh. Currently, the best performing units can only achieve approximately 1,800 lbs CO_2/MWh for coal-fired boilers creating a situation where no new coal-fired generation can be built absent any post-combustion CO_2 removal.

5. The section 111(b) rule sets a standard that is not technically feasible with existing control technologies. The rule continues to rely on carbon capture and storage as a means of reducing CO_2 emissions beyond what power plant emission control technology could achieve. This is inappropriate because the technology is not commercially available at the scale necessary to achieve

the standard. The captured CO_2 can only be stored in geological strata suitable for permanent sequestration.

6. The rule dealing with existing sources under section 111(d) was proposed on June 2, 2014, and was published in the Federal Register on June 18, 2014. The voluminous rule, some 1700+ pages, required significant staff time within the Cabinet to dissect and analyze. The state fleet-wide average target for Kentucky was set at 1,763 lbs CO_2/MWh, meaning that Kentucky's fleet of existing coal-fired boilers, currently averaging 2,166 lbs CO_2/MWh (based on 2012 data), had to reduce its CO_2 emissions by 18.6 percent. It appeared EPA had produced a draft rule that considered variations among states' economies, energy profiles, and potential for bringing on low-carbon sources, and had set individual state targets based on those criteria.

7. The proposed rule also allowed states to convert the emissions target rate into a mass emission target expressed in tons of CO_2 reductions. This meant that Kentucky would have to reduce its 2012 emissions of 93 million tons of CO_2 from coal and natural gas units, to a 2030 target of 77 million tons.

8. The final version of the section 111(d) rule clearly demonstrates that EPA reversed course and abandoned its state-by-state approach in calculating emission reduction targets. Instead, EPA calculated targets based on three

electric transmission grid regions—the Eastern Interconnect, the Western Interconnect, and the Electric Reliability Council of Texas (ERCOT). This is a significant and unexpected departure from the proposed rule. The final rule did not provide a rational explanation for the selection of regional interconnections over other available alternatives.

9. EPA applied a complicated formula utilizing projected efficiency upgrades to the EGUs, the expected potential for renewable energy development within the regions, and future natural gas combined cycle (NGCC) development to set separate national rate targets for coal-fired and NGCC generation. The targets, 1,305 lbs CO_2/MWh for coal and 771 lbs CO_2/MWh for NGCC, were then used to derive state-specific targets. EPA also set equivalent mass emission reduction standards for each state.

10. Kentucky's allowable rate is 27 percent more stringent under the final section 111(d) rule than under the proposed rule — the most significant change of any state when the final rule is compared with the proposed rule. Further, Kentucky's emission reduction obligation from the 2012 baseline increased from 18.6 percent to 31 percent, a 67 percent greater required reduction.

11. The EPA's methodology for calculating renewable energy potential is completely different from the methodology in the proposed rule. The EPA

selectively chose a high wind development year—2012—and projected that as the "potential" growth for renewable energy in Kentucky's region. Congress provided temporary tax credits for renewable energy development which accounted for the sharp increase in wind energy projects in 2012. Thus, the EPA acted arbitrary in using that figure to project the renewable energy potential for states.

12. The infrastructure is not in place for renewable energy to be dispatched to Kentucky. Presuming renewable energy is made available from distant states to Kentucky, transmission lines must be in place that may go through several other states.

13. The rule should be withdrawn and reopened for comments based on the multiple components of the final rule that were not a logical outgrowth of the proposed rule. The final rule is a totally different rule from the proposed rule, and Kentucky was not provided adequate notice to submit comments on those components.

I declare under penalty of perjury that the foregoing is correct. Executed on this 22nd day of 2015, at Frankfort, Kentucky.

L.K. Peters

Leonard K. Peters

Commonwealth of Kentucky)
)
County of Franklin)

Subscribed and sworn to before me by Leonard K. Peters on this the 22nd day of October, 2015.

Vicki M. Craycraft
NOTARY PUBLIC
STATE AT LARGE

My Commission Expires:
May 19, 2018

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et. al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY Respondents.	Case Nos. __________

DECLARATION OF STUART SPENCER, ASSOCIATE DIRECTOR, OFFICE OF AIR QUALITY, ARKANSAS DEPARTMENT OF ENVIRONMENTAL QUALITY

I, Stuart Spencer, declare as follows:

1. I am the Associate Director of the Office of Air Quality at the Arkansas Department of Environmental Quality ("ADEQ"). I have been employed at the ADEQ for approximately five years. As part of my duties, I supervise a staff of approximately eighty employees. The ADEQ Office of Air Quality has received all delegable air programs, including the Title V program for major sources of pollutants, from Region 6 of the United States Environmental Protection Agency

(EPA). These programs include the New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), Prevention of Significant Deterioration (PSD) and the State Implementation Plan (SIP). By working closely with businesses and industries, the ADEQ Office of Air Quality issues permits that help maintain and improve the air quality for all citizens in the State. The Office of Air Quality has four branches; Program Support, Planning and Air Quality Analysis, Permits, and Compliance Monitoring. I have personal knowledge and experience to understand the steps that the State of Arkansas has taken and will need to undertake in response to the EPA's Section 111(d) Rule.

2. Based on my experience, I have determined that implementing the Section 111(d) Rule will be a complicated and time-consuming endeavor. The Section 111(d) Rule is unlike any other Clean Air Act implementation undertaken by the State of Arkansas. Specifically, the Section 111(d) Rule's reliance on measures that require the reduction of demand for a particular source of energy - building blocks 2 and - are entirely unprecedented. The State of Arkansas will be required to expend a large number of resources to design a State Plan that incorporates these building blocks.

3. Already, six employees have expended approximately 300 hours on understanding the Section 111(d) Rule and preparing for its implementation, including, but not limited to:

a. Reading the rule and associated technical documentation;

b. Attending briefing sessions with State officials;

c. Participating in group calls and webinars on the final rule;

d. Participating in states' groups discussions on the final rule;

e. Preparing presentations on the final rule for various state and local groups;

f. Outreach and communications with affected facilities and stakeholders;

g. Preparation for press events and initial stakeholder meeting post-final rule; and

h. Preparing for and hosting a 111(d) stakeholder meeting on October 9, 2015 at ADEQ headquarters.

4. Absent a stay from this Court, it is not practical for the State of Arkansas to wait to continue work on its State Plan. It is already doubtful that the ADEQ can design a State Plan in time to comply with the EPA's deadlines. Waiting until the litigation concludes will make compliance with the EPA's deadlines impossible. And any delay in designing a State Plan will risk the State of Arkansas's ability to comply with the EPA's deadlines. ADEQ foresees that the preparation of a State Plan will entail a lengthy process. The usual timeline to

develop a SIP averages 18 months, which would include (in regards to preparing a state "Clean Power Plan"):

a. research and development of a State Plan and accompanying regulation language, including requisite analyses under Arkansas Act 382 of 2015, which mandates that any State Plan must be approved by the Arkansas General Assembly prior to submission to the EPA. Additionally, Act 382 requires that any State Plan must be supported under state law by a number of analyses, including economic, rate payer and reliability impact assessments;
b. internal review of draft language;
c. submission of any proposal to the Governor and legislature;
d. rulemaking initiation with the Arkansas Pollution Control and Ecology Commission (hereinafter "APC&EC");
e. submission of rulemaking packet to Legislative Committees for approval;
f. adoption of rulemaking with the APC&EC;
g. final development of draft § 111(d) State Plan;
h. public notice and public comment period;
i. response to comment (time can vary according to the number and comments received); and

j. submittal of the State Plan to EPA.

(See also attached Rule 111(d) Plan Development and Submission Timeline)

Plans including controversial issues or multistate efforts can reasonably be expected to take longer. Considering all these steps necessary to develop a State Plan, the State of Arkansas will require significant resources and time, which are not available at the state level, to develop and implement an approvable plan.

i. In addition, it is uncertain whether any State Plan will be approved by the EPA and implemented in time for utilities to comply with the Section 111(d) Rule's interim goals, making any delay in expending resources impractical. Waiting until litigation is complete to begin work on a State Plan would make it impossible for the State of Arkansas to meet the Section 111(d) Rule's interim and final compliance goals, and any delay in designing a State Plan will risk the State of Arkansas's ability to comply with the EPA's deadlines.

ii. Absent a stay from this Court, planning and compliance for the Section 111(d) Rule, including designing a State Plan, will require an unprecedented amount of ADEQ resources, the expenditure of which will begin immediately. The Section 111(d) Rule gives the State of Arkansas until September 6, 2016, to submit certain elements of its State Plan. If EPA approves, the State will have until September 6, 2018, to submit a final State Plan. Preparation of a a timely plan will require several dedicated ADEQ staff members, as well as significant resources from other state agencies, stakeholders, and the legislature.

The ADEQ and the Arkansas Public Service Commission (APSC) initiated the post-final Clean Power Plan rule stakeholder process via a meeting held at the ADEQ headquarters on October 9, 2015. The October 9th meeting was attended by approximately two dozen primary stakeholders, as well as a room full of interested individuals, entities and organizations. Several ADEQ staff members attended the meeting and undertook more than 85 cumulative hours of preparation and presentation time. The objective of the stakeholder gathering was to gauge the primary issues of concern and interest and to set the framework for further meetings. At this point in time, all options are on the table and under consideration, as long as they achieve the directive ADEQ has received from Arkansas's Governor to seek the lowest cost option for compliance.

The ADEQ is currently mapping out its strategy for future stakeholder engagement. At a minimum, it is estimated that we will hold at least ten meetings, including educational listening sessions, over the next year. It is estimated that staff will expend at least 600 cumulative hours in preparation for attendance at those meetings.

iii. Absent a stay from this Court, if the State of Arkansas chooses to adopt a multi-state approach to complying with the Section 111(d) Rule, the State of Arkansas may need to enter into either a memorandum of understanding or agreement with the other states. The State of Arkansas has limited experience in pursuing this type of agreement with other states, and anticipates that a significant amount of time would be required to negotiate and reach consensus on the content of such an agreement with other state agencies.

iv. Undertaking these measures will seriously disrupt the State's sovereign priorities, which would otherwise be devoted to addressing other pressing issues of public concern. The ADEQ has already identified a number of concerns with the final rule that will require State resources to address. The fundamental areas of concerns are potential economic impacts and the timing associated with implementation of the rule (specifically, artificial time constraints imposed by the rule). The ADEQ also is concerned with ensuring that our electric generating units that are currently in operation are allowed to run the course of their "remaining useful lives." Premature closure of a plant will result in stranded assets, the costs of which will be borne by electric consumers. Moreover, we want to ensure that the State is given proper credit for projects currently underway that are already part of the utility integrated resource planning (IRP) process. Additionally, at this point, there is uncertainty as to what a federal plan will look like (it is proposed). Failure to act or plan could result in a federal plan which does not allow sufficient flexibility to meet load demand, protect natural resources, and assure lowest cost energy. It is difficult to weigh options (i.e., state plan or federal plan), if the parameters of the federal plan are as yet undefined. The final rule also raises concerns about certainty and predictability of energy supply and costs critical to new load demand and economic development.

I have prepared the above and foregoing statements and they are true and correct to the best of my knowledge and belief.

IN WITNESS WHEREOF, I hereunto set my hand this 16th day of October, 2015.

Stuart Spencer
Associate Director, Office of Air Quality
Arkansas Department of Environmental Quality

SUBSCRIBED AND SWORN TO before me, a Notary Public, this 16th day of October, 2015.

Sarah Martin
Notary Public

My Commission Expires:

9-7-2024

SARAH MARTIN
FAULKNER COUNTY
NOTARY PUBLIC - ARKANSAS
My Commission Expires September 07, 2024
Commission No. 12400461

"Clean Power Plan"/111(d) Plan Development and Submission Timeline

2015

August 3	Federal	EPA releases final "Clean Power Plan" rule and proposed Federal Plan
Mid-October	Federal	Projected publication of the final "Clean Power Plan" rule in the Federal Register
October	State	ADEQ/PSC convene stakeholder roundtable meeting/develop stakeholder meeting schedule
December/January 2016	State	Complete development of assumptions/scenarios in order to run models required by Arkansas Act 382 (process will involve stakeholders, state agencies [ADEQ, PSC, AEDC] and possibly contracted consultants)

2016

January –May	State	Conduct and complete Arkansas Act 382-required analyses of utility-costs-impact, environmental -impact, and economic-impact
May-June	State	Develop 111(d) "Initial Plan"
July	State	Brief Governor's Office/General Assembly with draft 111(d) "Initial Plan"
Sept. 6	Federal	Extension request/"Initial Plan" due to EPA.
September–September 2018	State	Rulemaking/State Plan development/stakeholder engagement/inter-agency engagement (subject to legislative and Governor's approval).

2017

September 6	Federal	State's "Progress Report" on "Initial Plan" due to EPA.

2018

September 6	Federal	State's Final Plan due to EPA.*

*September 6, 2018 deadline is subject to EPA approval of state's September 6, 2018 extension request and "Initial Plan".

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ______

DECLARATION OF PATRICK STEVENS,
WISCONSIN DEPARTMENT OF NATURAL RESOURCES

I, Patrick Stevens, declare as follows:

1. I am the Division Administrator of the Environmental Management Division at the Wisconsin Department of Natural Resources ("WDNR").

2. I have personal knowledge and experience to understand what steps the State of Wisconsin has taken and will need to undertake in response to the EPA's proposed *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units*, 79 Fed. Reg. 34, 830 (June 18, 2014) ("111(d) Rule").

3. Based on my experience in this position, I have determined that implementing the 111(d) Rule will be a complicated and time-consuming endeavor. In terms of scope and level of effort, the 111(d) Rule is unlike any other Clean Air Act implementation activity undertaken by the WDNR in recent

history. Already, WDNR employees have expended over 3200 hours understanding the proposed rule and evaluating potential implementation options, including outreach to numerous stakeholders[1] in Wisconsin, organizing individual and joint stakeholder meetings and listening sessions, participating in regional collaborative efforts with other states and industry participants such as Midcontinent States Environmental and Energy Regulators and the Midwest Power Sector Collaborative, attending EPA listening sessions and conference calls, and in-depth analysis of the impact of the 111(d) Rule on the state and regional systems.

4. WDNR also expended significant resources to understand how the proposed 111(d) Rule would impact energy providing utilities, including investor-owned utilities, municipal utilities, and co-operative utilities. WDNR, together with the Public Service Commission of Wisconsin ("PSCW") has studied each utility's unique fleet of electric generating units, interactions among the different utilities, interactions between in-state and out-of-state facilities of an individual utility, and the interaction of Canadian hydro-electric power with the state and regional system.

5. Much of the time and energy invested in understanding and evaluating the proposed rule is irrelevant to the final 111(d) Rule. The final 111(d) Rule is significantly different, which means WDNR staff has begun another intensive investigation into the requirements of the Rule and start over with evaluation of compliance paths. Similarly, if the Rule is not stayed and the Rule is altered or vacated, much of the time and energy invested in understanding and compliance planning for the final 111(d) Rule may have been wasted.

6. State government resources necessary for implementation of the 111(d) Rule are expected to be even greater than what has already been expended. The 111(d) Rule gives the state until September 6, 2016, to submit an initial state plan, with a two-year extension available. In the event Wisconsin decides to prepare a state plan, preparing and submitting a timely plan will require several dedicated WDNR staff members, as well as significant resources from other state agencies, stakeholders,

[1] Stakeholders include regulated utilities, merchant-owned EGUs, municipal utilities, utility cooperatives, environmental groups, industry groups, residential and small business representatives, MISO, M-RETS, and representatives from other entities interested in or impacted by the 111(d) Rule.

and the legislature. Though the time to submit a plan was extended in the final rule, the emissions reduction goals must still be met by 2030. Therefore, absent a stay, compliance planning and implementation must both begin immediately in order to meet the final goal. Any delay in submitting a final plan for approval will only reduce the amount of time Wisconsin has to implement that plan. If the rule is not stayed during litigation, and is ultimately vacated or amended, significant time and resources will be wasted on compliance planning and implementing the current 111(d) Rule.

7. Both the proposed and the final 111(d) Rule include measures that are not within the direct control of either utilities or the WDNR, and will require large scale changes to environmental regulation in Wisconsin. The final rule sets a rate for existing plants that is not achievable absent measures taken outside of the plant's boundaries. WDNR's current authority is limited to regulation of stationary sources, as well as some mobile sources, of emissions. In order to have the ability for WDNR to directly regulate and enforce in-state compliance options of the plan that are outside of the fence-line of the stationary sources, such as energy efficiency and increased reliance on renewable energy, the Wisconsin Legislature will have to re-write state statute to fundamentally change the WDNR's authority. Furthermore, it is unknown how the Legislature would react to any such proposal. These complications highlight the difficulty of creating an enforceable compliance path either as an individual state or as a region since many of the carbon-reduction measures are not within the direct control of the regulated utilities. Legislative changes would be most appropriate after the rule is fully adjudicated.

8. More specifically, the process to create a state plan for the 111(d) Rule includes several required steps and will take three or more years to complete. The 111(d) Rule describes at least six potential compliance plan options available to the states. EPA identifies seven specific elements that every state plan must include, not including additional demonstrations that a state has considered electric system reliability in developing its plans and that the state engaged all stakeholders potentially impacted by the plan. In addition, EPA specifies certain additional components that certain plans must include, including a demonstration that the plan's reductions are quantifiable, non-duplicative, permanent, verifiable, and enforceable. Some compliance options could require additional legislative changes. The

111(d) Rule should be stayed during litigation because a policy change this significant should not be pursued until the legality of the 111(d) Rule is definitively determined.

9. Demonstrating that Wisconsin's 111(d) state plan meets all necessary components will require Wisconsin to develop and finalize new state rules and potentially acquire statutory changes by September 6, 2018, assuming Wisconsin receives a two-year extension. WDNR estimates that a simple, noncontroversial state rule takes at least 27½ months to complete all steps required under Wis. Stat. ch. 227, Subchapter II. In my experience, the complex and contentious 111(d) Rule will take significantly longer than the timeframe for a simple, non-controversial rule because of the stakeholder input required for such a comprehensive regulation of the entire electric generating system. In addition, the federal requirements for adoption and submittal of state plans at 40 C.F.R. 60.23 also include requirements for public hearing and opportunity for comment. In my opinion, it will be difficult and will require dedicated resources for Wisconsin to complete a state plan within the timeframes allowed in the 111(d) Rule. Absent a stay of the Rule, these state law changes may ultimately need to be reversed or otherwise changed again once litigation is complete.

10. In the absence of a stay, it is not practical for WDNR to wait for the completion of litigation to begin working with utilities on compliance. It is already doubtful that the state plan will be approved and implemented in time for utilities to comply before the first interim goal compliance period in 2022. Waiting until litigation is complete to begin that work would make it impossible for Wisconsin to meet interim goals, and even more costly and difficult to meet the final 2030 goal. In the event the state chooses to participate in certain compliance options involving a multi-state plan, the state may need to enter into either a memorandum of understanding or agreement with the other states. For example, under certain multi-state planning scenarios, EPA requires states to agree upon a joint emissions reduction goal equivalent to the individual goals of each participating state and to document the analytic process, tools, methods, and assumptions used to calculate the joint multi-state goal. The state has limited experience in pursuing this type of agreement with other states, and anticipates that a significant amount of time would be required to negotiate and reach consensus on the content of such an agreement with other state

agencies. This time-consuming process would be a waste of resources if the 111(d) Rule is ultimately changed or vacated. Even a minor adjustment in goals for participating states, compliance options available, or compliance time could dramatically change the compliance plan. Given the lengthy planning process for writing, submitting, and approval of a plan, and associated state law changes, it is likely it would not be practical to re-submit a new compliance plan within the 111(d) timeframes if litigation alters the final 111(d) Rule but does not stay compliance during litigation. Utilities affected by the state's originally submitted compliance plan will likely have already made adjustments to their operation, rendering a successful legal challenge useless.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Executed on 10/16/15

Patrick Stevens

IN THE
UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF WEST VIRGINIA, STATE OF TEXAS, *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and REGINA MCCARTHY, Respondents.	Case Nos. ______

DECLARATION OF TED THOMAS, CHAIR, ARKANSAS PUBLIC SERVICE COMMISSION

I, Ted Thomas, declare as follows:

1. I am the Chair of the Public Service Commission of Arkansas ("APSC"). I have been Chair of the APSC since January, 2015 and was previously employed at the APSC as an administrative law judge for 7 years. As part of my duties, I have authority to monitor, track, and interact with stakeholders and regulators on the development and implementation of state and federal environmental rules impacting public utilities. The primary responsibility of the APSC is to set just and reasonable rates for utility service provided by regulated

utilities in Arkansas. Rates are based on the cost to provide service and regulations have a substantial impact on costs.

2. I have personal knowledge and experience to understand what steps Arkansas has taken and will likely need to take in response to the EPA's Section 111(d) Rule, including future resource planning for system reliability. In general, the Section 111(d) Rule could dramatically transform the way electric power will be generated and transmitted to consumers in Arkansas and throughout the United States. The ultimate cost of the rule will be determined by future price movement of natural gas, renewable energy resources, energy efficiency products and other commodities and products used in the generation and transmission of electric energy. The Rule could have devastating effects on consumers of electricity and on economic development investment necessary to create jobs. The Rule may require the construction of new power plants and associated infrastructure, the updating or decommissioning of existing power plants that are not fully depreciated, and the reduction in overall energy consumption by every single current and future consumer of electric power. In short, the Section 111(d) Rule will transform the American energy economy, and may devastate the economy.

3. Based on my work experience and position, I have determined that implementing the Section 111(d) Rule will be a complicated, time consuming, and

expensive endeavor, which will require the expenditure of substantial State resources, immediately, over the next calendar year and into the future.

4. Significant APSC resources have already been invested to understand and evaluate the proposed 111(d) Rule. APSC employees have spent hundreds of hours understanding the rule and preparing for implementation, including outreach to all Arkansas stakeholders, organizing stakeholder meetings and listening sessions, participating in regional collaborative sessions such as Mid-Continent States Environmental and Energy Regulators with other states and industry participants, attending EPA listening sessions and conference calls, and in-depth analysis of the impact of the Section 111(d) Rule on the state and regional systems. I estimate that since I have assumed my current position that 10%-15% of my time has been spent on issues related to the 111(d) Rule.

5. APSC employees have spent hundreds of hours modeling and reviewing modeling results for the likely compliance scenarios, and will spend additional time and resources modeling the changes made from the proposed to the final Section 111(d) rule. The purpose of this model is to forecast the cost of the changes in the MISO and SPP wholesale electricity markets to try to determine the cost to comply with the Section 111(d) Rule, and to compare the option of a state-only compliance plan with the option of a regional compliance plan. With input from stakeholders, engineers from the APSC assisted in building a model using the

"Electric Generation Expansion Analysis System (EGEAS)". Several model runs were completed, analyzed, and presented with our comments to the EPA. We also presented the modeling results in several different conferences with numerous stakeholders.

6. Based on my knowledge and experience, the Section 111(d) Rule represents an unprecedented infringement by the EPA on the traditional authority of the State of Arkansas to manage energy resources within our jurisdiction because the mandates of the Section 111(d) require APSC to undertake specific changes to how energy is provided to consumers or face devastating potential cost consequences. The Section 111(d) Rule also disrupts the well-settled division of authority over electricity markets under the Federal Power Act, and raises significant uncertainty about the role of the Federal Energy Regulatory Commission to ensure the reliability of electricity through the wholesale market.

7. Absent a stay from this Court, compliance planning must begin immediately. The system-wide changes necessary for compliance must be gradual to preserve reliability of the electric grid. Because compliance is calculated based on a rolling average, the longer Arkansas waits to begin compliance, the more expensive and difficult it will be to meet the requirements of the Rule.

8. Absent a stay from this Court, evaluation of specific compliance measures, such as new facilities or retirements, must also begin immediately. The

lengthy application and approval process for utilities to construct, upgrade, or retire facilities to comply with the Section 111(d) Rule, as well as the in-depth evaluation of public necessity and convenience for each facility, requires utilities to plan and submit applications for upgrades almost immediately after publication of the final Section 111(d) Rule in order to have equipment constructed, upgraded, or decommissioned before the compliance period begins in 2020. The Section 111(d) Rule also requires decisions to be made on future price projections which exposes Arkansas ratepayers to great risk should prices be different that the projections.

9. Absent a stay from this Court, the APSC will need to spend hundreds if not thousands of hours and tens of thousands of dollars over the next calendar year as a direct result of the Rule. The expenditure of these resources must begin immediately.

10. Arkansas utilities are members of two Regional Transmission Organizations ("RTOs") that exist to plan and manage the electric transmission grid. The planning and construction process for new transmission infrastructure is 5 to 7 years. The 2018 plan submission deadline, the 2020 early action benefit deadline and the 2022 plan implementation deadline all require beginning of action if new transmission infrastructure procured by existing processes is to be included in an implementation plan. The time required to plan and construct new transmission assets also pushes forward the time that price estimates must be made,

further increasing the risk to consumers of unexpected prices. Regulators are faced with a choice of requiring utilities to invest large sums of money on trasmmission infrastructure based on projections of prices in 5-10 years, or delaying approval of transmission investment which takes some generation options off the table. Absent a stay from this Court, the Section 111(d) Rule places significant risk on Arkansas consumers if the best estimates of future prices turn out to be wrong. The Section 111(d) Rule could also severely threaten reliability and increase the cost of electricity by forcing Arkansas to move immediately toward reliance on a limited number of fuel sources based on the best guess of what prices will be. The risks associated with this type of system-wide transformation will begin in the next year and require decisions to be made earlier based on longer term forecasts unless the Rule is stayed.

11. Changes made for the sake of compliance with the Section 111(d) Rule immediately and over the next calendar year could be irreversible and will impact the electric grid for decades. Alternatively, the State of Arkansas can wait on the outcome of litigation and find that some compliance options are foreclosed because there is insufficient time to construct transmission assets. This "catch-22" places substantial risk on Arkansas ratepayers. System planning is typically based on the 30-40 year lives of generation and transmission facilities. Building, redesigning, and adjusting power generation facilities takes years, and decisions

made in these areas are often irreversible once they are made. For example, the decision to prematurely retire an electric generating unit could have significant consequences for system reliability and may unnecessarily increase costs to ratepayers for decades to come.

12. Absent a stay from this Court, various options for implementation of the Section 111(d) Rule will require legislative and constitutional changes on the state level that may permanently alter the daily operation of utilities. Specifically, the Section 111(d) Rule includes control measures outside of the physical location and control of electric generating units, such as end-use energy efficiency (reduced energy use by electricity consumers), demand response (usage changes according to instantaneous market and load-profile changes), and increased distributed generation (such as small residential renewable installations). Arkansas would have to immediately set in motion the chain of events, including statutory changes, larger investment in customer-side behavior, and further rate restructuring, in order for these compliance options to contribute to the Section 111(d) Rule's emission reduction targets. Alternatively, Arkansas could wait and not pursue statutory and constitutional changes and later discover that it was disadvantaged by the delay because of the movement of future prices and the extended planning periods for large scale utility operations.

13. To attempt to comply with the Section 111(d) Rule, Arkansas will seek a path forward as if each of a number of alternative suppliers of energy will turn out to be the least cost to Arkansas ratepayers. Arkansas will attempt to remove any non-price barrios for new natural gas units and infrastructure, solar facilities and necessary transmission facilities, wind facilities and transmission facilities, combined heat and power, demand response, energy efficiency targeted to low income areas as required by a part of the Section 111(d) Rule, and any other such options made available by technological improvements. Each will require review of current law and possible legislation or constitutional amendment relating to governmental financing or other incentive programs. Undertaking these measures will seriously disrupt the State's sovereign priorities, which would otherwise be devoted to addressing other pressing issues of public concern.

14. The State of Arkansas is required under Section 111(d) Rule to make significant changes to what sources are used to provide electric energy and how it regulates providers of electric energy. These decisions will necessarily involve a large capital investment, eminent domain issues associated with major transmission investment, significant statutory revisions and reliance upon projections of costs of numerous products and commodities. Absent a stay from this Court, these decisions will be made in an atmosphere of uncertainty in which the initial decisions will impact and limit later decisions. Options might be

impaired by the passage of time and commitments made too soon might prove to be poor choices. The most if not all of the financial risk associated with the decisions will be borne by the ratepayers of Arkansas.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Executed on 10/22/2015

Ted Thomas

ACKNOWLEDGMENT

STATE OF ARKANSAS

COUNTY OF PULASKI

On this the 22nd day of October, 2015, before me, Karen R. Wesson, the undersigned officer, personally appeared Ted Thomas, known to me to be the person whose name is/are subscribed to the within instrument and acknowledged that he/ executed the same for the purposes therein contained.

In witness whereof, I hereunto set my hand and official seal.

Karen R. Wesson

Notary Public

Printed Name: Karen R. Wesson

My Commission Expires:

KAREN R. WESSON
Notary Public-Arkansas
Jefferson County
My Commission Expires 09-16-2024
Commission # 12400984

9-16-2024