more and more uneconomical to operate and ultimately enter into a "death spiral," the outcome of which is the closure of both the plant and the mine.

19. Additionally, STEC presently has no power contracts in place or other resources to make up the power lost if San Miguel were to close. Furthermore, as discussed in more detail below, the revenue from operating San Miguel is the only substantial source of revenue available to pay San Miguel's outstanding obligations (consisting of debt, decommissioning costs and mine closure costs) which are projected to be approximately $489 million at December 31, 2015. Assuming the above-referenced agreement between BEPC and STEC is ultimately consented to by RUS and becomes effective, STEC will pay-down these obligations by $127.5 million out of funds provided in conjunction with the agreement with BEPC. Therefore, the remainder of this declaration will reference a range of outstanding obligations between $362 and $489 million to reflect this possibility.

Reduced utilization or closure of San Miguel's plant would adversely affect socio-economically disadvantaged consumers

20. By creating conditions that will force under-utilization and, ultimately, the premature retirement of San Miguel's power plant, EPA's 111(d) Rule will cause irreparable harm, as I understand the meaning of that term, to San Miguel, its members, and their customers, many of whom live at or near the poverty level and cannot afford even modest increases in their electric bills. As

explained below, this includes harm that will occur while the legality of the 111(d) Rule is being litigated, if the Rule and its deadlines are not stayed.

21. San Miguel is located near Christine, Texas, population 390, in Atascosa County. It is my understanding that both Christine and Atascosa County are majority Hispanic in population make up. About one third of the families and population in Christine live below the poverty line, including almost half of those under 18. About one fifth of the population of Atascosa County, including about one fourth of those under 18, live below the poverty line.

22. San Miguel is a pivotal employer in Atascosa County. Through its power plant and mine, San Miguel directly employs 419 individuals, and, in addition, employs hundreds of other contractors throughout the year.

23. The ultimate end users of much of the power that San Miguel provides are socio-economically disadvantaged and cannot afford even modest increases in their electric bills. In particular, the members of STEC, all of whom are also members of San Miguel, provide electric service to over 236,000 customers in 44 Texas counties, including some of the poorest counties in Texas and, indeed, in the United States, including Starr, Willacy, Dimmit, Hidalgo, Zavala, Brooks, Zapata, Bee, Webb, Cameron, and Duval counties.

Accelerated rate-recovery of debt, plant decommissioning, and mine closure obligations

24. If the first compliance date in the 111(d) Rule of 2022 stays in place and forces retirement on that date, San Miguel will be forced to accelerate payment of outstanding debt, the cost of decommissioning the plant, and the cost of closing the mine. These obligations total anywhere from $362-$489 million. At present, because the engineered life of the plant is 2037, the Wholesale Power Contracts are structured under the assumption that San Miguel's remaining debt, the costs of decommissioning and retiring the plant, and the costs of closing the mine can be recovered over the next 22 years. If San Miguel must prematurely retire the plant (because of the 111(d) Rule), those assumptions must change.

25. The threat of having to retire its sole revenue-generating asset in 2022 would present San Miguel's Board with the dilemma of deciding when and how to address payment of these outstanding obligations. The Board may be forced to accelerate repayment of San Miguel's outstanding obligations during the few short years before the unit is forced to retire, rather than over the 22-year period between now and 2037. Such an accelerated repayment schedule will dramatically increase the costs to San Miguel's members. In addition to recovery of the outstanding obligations, it will be necessary for the members of San Miguel to replace the power that was once provided by the existing San Miguel unit. Although neither the STEC nor San Miguel Boards of Directors have instructed me to produce detailed cost estimates of the cost of replacement power, my understanding of

market conditions and capital costs associated with constructing new generation assets and associated infrastructure leads me to conclude that San Miguel would be exposed to dramatic additional debt obligations which would be untenable given the circumstances, discussed at length below, that will result from the premature retirement of the existing San Miguel unit.

26. Without a stay of the 111(d) Rule and the deadlines associated with it, San Miguel's board must immediately begin to make decisions without the benefit of knowing the Rule's legal fate. This could include a decision to accelerate recovery of these obligations immediately on the chance that the Rule will be upheld so as to spread out the impact of premature closure as much as possible (which will still result in immediate, substantial rate increases) or wait until legal clarity is achieved and thereby defer accelerated recovery of these obligations, which, if the Rule is upheld, will force these rate increases to be imposed over an even shorter time period, resulting in a much more dramatic impact on rates because of the compressed timeframe for recovery.

27. For example, even if it is assumed (a) that all legal challenges to the 111(d) Rule are finally resolved by June 2017 and (b) that the Rule is upheld, the earliest San Miguel will be able to discern the legal fate of the Rule and, thus, whether it will be forced to close its power plant, is when it establishes its 2018 budget. If San Miguel's Board does nothing until the legal challenge is resolved,

this would leave just four years of operating life over which to address over $362 million in outstanding obligations (assuming the Rule is upheld in a form that requires San Miguel to retire the plant in 2022). If, as is entirely possible, the legal challenges are not resolved until June 2019, this period will be compressed into only two years. Even assuming the Rule is ultimately upheld, a stay of the Rule and its deadlines would give back to San Miguel and its members (and ultimately, the consumers of the power produced by San Miguel's plant) the time period during which the legal challenges were being considered over which to spread out the impact of the premature closure of the power plant and the mine.

28. San Miguel has conducted an analysis of rate impacts of an accelerated recovery of these obligations assuming certain resolution timelines. If San Miguel awaits judicial resolution before acting, rate increases for its member cooperatives would likely be between 85 and 125%. If San Miguel does not await judicial resolution, but instead acts immediately, rate increases for its member cooperatives would likely be 51% over the 2015 rate for the next 6 years.

29. Whichever option the Board chooses, San Miguel and its members, will be exposed to dramatic, irreparable harm that could be eliminated or at least mitigated by the Court's suspension of the 111(d) Rule and its compliance deadlines so that San Miguel can continue to operate its sole revenue-generating

asset and spread out the impact of accelerated rate recovery for these obligations over a greater period of time.

Increased cost of current mine operations incurred in order to defer further investment in future mine areas.

30. As mentioned above, San Miguel is a mine-mouth lignite coal-fired power plant. San Miguel currently has two mining permits covering approximately 20,444 acres. Over 9,100 acres within the two permit boundaries have been mined and there are an additional 1,671 acres within the permit boundaries that will be mined. This lignite coal surface mine exists only to develop and deliver lignite coal to San Miguel's power plant, which is the sole source of fuel for the plant. Therefore, the operation of the power plant is inextricably tied to the operation of the lignite coal mine.

31. Every step of operational planning for the power plant has direct implications for the mine and vice versa. The plan for operating the mine is directly tied to the engineered operational life of the plant. That is, San Miguel's current business plan is to mine lignite coal from the mine until 2037 in order to run the plant through 2037. Accordingly, the risk that the 111(d) Rule could significantly shorten the life of the power plant also affects San Miguel's plans for the mine.

32. There are significant operational decisions that must be made about the mine before final judicial resolution of the 111(d) Rule can reasonably be

expected to occur. As is typical in surface mining operations, it costs more to mine from some areas than others. The primary causes of these higher costs are the distance of the in-situ lignite coal from the power plant and the depth of the lignite coal from the surface. A prudent, cost-effective mine plan takes this into account and includes a schedule for the progression of mining that minimizes costs and maximizes production. Typically, under such a plan, areas of lower-cost lignite coal are mined concurrently with the areas of higher-cost lignite coal to balance the overall cost impact to its members, as well as balance the quantity and quality of the lignite coal. San Miguel's current mine plan includes such a progression through 2037.

33. The mine plan divides the permitted land into separate areas that are scheduled to be mined in conjunction with other areas that have been determined to be the best match to balance out cost, quantity and quality of lignite coal. Thus, it is not the case that mining begins at one end of the mine and progresses steadily to the other. As areas of the mine are depleted, new areas are opened, and there are significant costs—primarily related to infrastructure—associated with opening new areas, which include: construction of ponds and diversions to control drainage and capture runoff from disturbed areas, the construction of all-weather roads, bridges and overpasses for the haul trucks, and the installation of power lines for the draglines.

34. One area of the mine that currently supplies San Miguel its fuel is nearing the end of its economically recoverable reserve of lignite coal. Therefore, San Miguel's mine plan contemplates opening a new mining area (known as the "South Lease") beginning in 2016 with infrastructure construction activities, and commencing with lignite coal removal in 2017. Operating the South Lease would require immediate and significant additional capital expenditures that, in the face of the current compliance deadlines in the 111(d) Rule, could only be made at great risk. Consideration for capital investment in both the plant and mine requires planning years before making any new investments. Construction of mine infrastructure and the obtaining of mining permits requires many years of advance planning. Therefore, any additional investment made in opening the South Lease would be made at significant risk and add to the already significant debt and plant and mine closure obligations of approximately $362-$489 million discussed above and below.

35. Typically, the additional capital expense of opening a new mining area is justified because it provides lower cost fuel to balance out the higher cost of fuel that is left in the existing areas. The 111(d) Rule fundamentally alters this cost-benefit analysis for San Miguel, presenting the Board with two equally unattractive options: (1) enter the new mining area as planned and possibly expose its members to even higher rate increases if the Rule is upheld, due to increased

infrastructure construction capital and debt and closure obligations or (2) forego the cost of opening the new mining area and continue to mine higher-cost fuel while the legal challenge to the Rule plays out. The latter option would cause harm to San Miguel's members not only because it would result in higher short-term electricity rates (because the cost of the fuel is higher) but it would begin the "death spiral" as explained in paragraph 18. The power plant would be dispatched less due to higher fuel costs and the fuel costs would increasingly become higher because there would be fewer megawatts sold.

36. Once the permits are approved for the South Lease, San Miguel has only a limited window of time to begin mining to maintain the balance of cost, quantity and quality of fuel that is critical for the power plant. Construction of key infrastructure including an overpass for Farm-to-Market Road 791 in Atascosa County, construction of an at-grade separation for a county road, haul roads, a creek crossing, sediment ponds, a dragline walkway, and installation of power lines and substations must be commenced no later than July 2016 in order to be ready for the dragline to begin mining lignite coal in 2017. Delays will result in further fuel cost increases and fewer megawatts sold. If mining does not begin within three years of the issuance of the permit (anticipated in June 2016), according to Section 12.219 of the Texas Coal Mining Regulations, the permit will be terminated. If mining operations are not initiated in the South Lease by June of

2019 and the permit is terminated, the reserves in the existing mine would be depleted before another permit could be issued and no fuel would be available for the power plant

37. San Miguel recently assessed the additional net costs that would be incurred if it chose not to enter the South Lease and instead continued to mine higher-cost lignite coal within the existing mine areas. The cost of entering the South Lease was estimated at $32 million. Ordinarily, this would be more than off-set by the benefit of being able to mine lower cost lignite coal from the South Lease as compared to areas presently being mined. The calculated total cost savings—with the capital costs of entering the South Lease factored in—are approximately $80 million saved over the six years that lignite would be mined in the South Lease.

38. Based on this analysis, San Miguel's Board decided to open the South Lease. However, the threat of premature closure of the mine from the 111(d) Rule may force reconsideration of this decision before any additional clarity can be received regarding the Rule's legal fate. If San Miguel does not open the South Lease, its rates will increase because the cost of mining lignite coal from the existing areas of the mine is higher than would be the case if the South Lease were opened as planned. If the requested stay is not issued, but the Rule is ultimately struck down, the decision the Board was forced to make that increased rates in the

meantime, will result in irreparable harm to San Miguel's members because they will have paid higher rates than they would have solely because of the threat of a Rule that is later found to be illegal. If the Rule is struck down and the Board then decides to move into the South Lease, and the permits have not expired, the infrastructure will have to be constructed on a compressed timeframe which will be more expensive due to inflation and the critical need to meet construction deadlines over cost.

39. If, on the other hand, San Miguel takes what would otherwise be the prudent course and opens the South Lease and the Rule is ultimately upheld, additional costs of approximately $32 million will be added to the approximately $362-489 million San Miguel has to recover in a compressed time frame as described above. A stay of the Rule and its deadlines will help mitigate this cost by affording San Miguel the certainty that it will be able to operate and generate critical revenues until 2024-2026 (depending upon how long the compliance deadlines are suspended). This would allow the above-referenced obligations to be recovered through rates for over 2-4 years longer than if the current 2022 compliance timeline were left in place. This additional time from a stay of the Rule and its deadlines would likely allow San Miguel to make the prudent business decision and go ahead and open the South Lease and thereby avoid the irreparable harm caused by having to exclusively mine more expensive lignite coal (the result

of not opening the South Lease), while at the same time avoid stranding the investments already made for the South Lease.

Risk of other stranded investments at the mine

40. In addition to the South Lease mining area discussed above, San Miguel has established a future mine area known as the "Franklin Ranch" to meet the plant's needs from approximately 2023 through 2037. Once the economically minable lignite coal reserves in the South Lease have been recovered, a mine plan has been developed that schedules the recovery of lignite coal underneath the Franklin Ranch to meet the fuel needs of the power plant until 2037. To secure access to fuel at both the South Lease and Franklin Ranch in a timely and cost-efficient manner, prudent mine planning demands that operators such as San Miguel secure leases and other rights necessary to access future mine areas years in advance. This may include paying advanced royalty payments to preserve the right of access to the lignite coal. In the South Lease mining area, extensive environmental baseline studies have been conducted and an application for a Permit to conduct surface mining and reclamation activities has been filed with the Railroad Commission of Texas. To date, San Miguel has paid a combined total of $6.5 million in advanced royalties, permitting and transactional costs to preserve the right to enter the South Lease and Franklin Ranch areas.

41. In 2016, final title searches will need to be conducted and the last leasing agreements will need to be secured for access to the Franklin Ranch. In 2017, the Board will face the decision whether or not to begin the extensive environmental baseline studies required for permitting the Franklin Ranch. In 2018, the permit application must be submitted to the Railroad Commission in order to be approved in time to begin infrastructure construction activities and be ready for mining in late 2022 or early 2023. Delays in the permitting process will delay the ability to go into the Franklin Ranch and leave only higher cost lignite coal as the fuel source for the power plant in the future, thereby compounding the above-referenced irreparable harm of higher rates moving forward.

Other stranded investments at the power plant

42. In addition to all of the foregoing, the premature retirement of the power plant will additionally strand other significant investments that have already been made at the plant. Among other things, as discussed above, San Miguel has invested approximately $130 million in environmental controls, including the controls listed in paragraph 15 above. These controls were installed so that the plant could continue to run until 2037. If the 111(d) Rule is upheld and the unit is forced to retire prematurely, the investments in those controls will be stranded.

Employment and other economic consequences of premature retirement

43. In addition to the consequences to its members, the forced retirement of San Miguel's power plant and mine will have consequences to local employment and to the local tax base. As mentioned above, San Miguel is directly responsible for over 419 jobs in addition to hundreds of contractor positions. It supports a payroll of $35 million annually, plus another $2.67 million in payroll taxes. It directly contributes more than $3.5 million annually in local taxes and payments and an additional $26.8 million statewide. The power plant and the mine indirectly support numerous other local businesses, further enhancing the state and local tax base.

44. There are significant indirect employment and economic impacts that will result from premature closure of San Miguel's plant and mine. For example, a 2014 study found that, in Atascosa County alone, San Miguel's operations support an estimated 969 direct, indirect, and induced jobs and over $276.6 million in annual economic activity, $51 million in annual salaries, wages, and benefits, and $38.7 million in annual state and local taxes. All of these benefits would disappear if San Miguel were to retire.

Conclusion

45. The 111(d) Rule abandons the long-established Clean Air Act framework, which allowed San Miguel to assess the cost of commercially available emissions reduction technology required by new EPA rules. Previously, despite

EPA's predictions to the contrary, San Miguel, through sound business planning, has been able to install new technology and still proceed with plant operation and mine development because the cost of additional controls did not offset the benefits of continuing to operate a low-cost, reliable power plant and continuing to develop a cost-effective lignite coal surface mine that ensures delivery of a long-term, low-cost fuel.

46. The 111(d) Rule, however, distorts the decision making process and burdens San Miguel and its members with the untenable decisions described above. A stay of the Rule and its deadlines until the conclusion of the legal proceedings challenging the rule will at least ensure that San Miguel's plant will be able to operate until 2024—and potentially until 2026—without facing the initial compliance deadline that, absent vacatur of, or substantive changes to, the Rule, will force the retirement of San Miguel's plant and closure of its mine. For the reasons discussed above, a stay will prevent, or at the very least mitigate, the harm San Miguel will incur while it waits for the Court to resolve the legal challenges to the Rule.

47. The only way San Miguel and its members will not suffer harm during the pendency of the legal challenges to the rule is if (a) San Miguel ignores the Rule and makes all business decisions as if the Rule never existed and (b) the Rule is struck down before the first compliance date. San Miguel may not be able to

take this course of action, however, even if it wished to, if it determined that doing so was not in its members' best interests or that any other course of action will cause harm for which no reasonable recovery is possible to San Miguel and its members. San Miguel should not be forced to choose between irreparable harm to itself and its members or ignoring the rule entirely and running the risk of its being upheld merely to exercise its legal right to challenge the rule.

I make this Declaration under penalty of perjury pursuant to 28 U.S.C. § 1746.

Derrick Brummett

Dated: 10/14/15

ATTACHMENT H

TO

MOTION OF UTILITY AND ALLIED PETITIONERS FOR STAY OF RULE

Declaration of Patrick F. Ledger (Oct. 14, 2015)

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

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION; ARIZONA ELECTRIC POWER COOPERATIVE, INC., *et al.*, Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, Respondent.	No. ______________

DECLARATION OF PATRICK F. LEDGER OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. IN SUPPORT OF MOTION TO STAY

I, Patrick F. Ledger, declare:

1. I am Chief Executive Officer for Arizona Electric Power Cooperative, Inc. ("AEPCO"). In that capacity, I serve as the executive manager of three associated electric generation cooperatives supplying power, transmission, power marketing, and other related services to six electric distribution cooperative members and other wholesale customers.

2. I have worked for AEPCO for 13 years. I obtained my B.A. from Colorado College. My master's and juris doctor degrees were earned from the University of Arizona.

3. AEPCO is a not-for-profit rural generation and transmission ("G&T") cooperative. The Apache Generating Station with its three steam units and four gas turbines is the only power generation station owned and operated by AEPCO.

4. AEPCO is composed of six Class "A" members, who are rural electric distribution cooperatives that collectively serve 12 counties in three states, numerous cities and eight tribes, or approximately 150,000 meters in total. Three of the six Class "A" members are all requirements members ("ARMs") who purchase all of their power needs from AEPCO and the other three are "partial requirements members" ("PRMs") who purchase a substantial portion of their power from AEPCO, but also have the capability of contracting on the market for other sources of power, subject to contract obligations with AEPCO.

5. The three Class "A" ARMs are Anza Electric Cooperative, Duncan Valley Electric Cooperative, and Graham County Electric Cooperative. The three Class "A" PRMs are Mohave Electric Cooperative, Sulphur Springs Valley Electric Cooperative and Trico Electric Cooperative. The smallest member, Duncan Valley Electric Cooperative, serves 2,315 meters with 453 miles of distribution line, while the largest, Sulphur Springs Valley Electric Cooperative, serves 52,999 meters with 4,059 miles of distribution line.

6. AEPCO is classified as a "small utility" because it sells less than the 4 million MWh or 750 MW net capacity threshold used under by the Federal Energy

Regulatory Commission ("FERC"). AEPCO also qualifies as a small business according to the U.S. Small Business Administration.

7. On August 3, 2015, the United States Environmental Protection Agency ("EPA") signed the final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units ("111(d) Rule" or the "Clean Power Plan") and was ultimately published in the Federal Register.

8. The 111(d) Rule requires an unprecedented reduction in fossil fuel-fired generation, with a 32 percent reduction in carbon dioxide (CO_2) emissions from 2005 levels required by 2030. The 111(d) Rule achieves those reductions through uniform CO_2 emission performance rate EPA has imposed on two subcategories of existing power plants (coal-and natural gas-fired units) and state-wide rate- or mass-based emissions goals that are formulated from the subcategory performance rates. States are required to formulate state plans for compliance and submit those plans to EPA for approval.

9. The rural nature of AEPCO's business means that fewer customers exist to share the costs of AEPCO's energy infrastructure. Because AEPCO is a not-for-profit cooperative, its Members must pay for any of AEPCO's expenditures, and AEPCO's costs are directly reflected in its rates for electricity.

10. Although states must plan for compliance, affected units like those owned and operated by AEPCO are ultimately responsible for compliance with the

interim and final goals established in the 111 (d) Rule. *See* 40 C.F.R. § 60.5855. By EPA's own admission, existing units cannot meet the new performance rates though any technological or operational changes at the unit without curtailing their generation or shuttering their plants, shifting generation to lower-emitting sources, and/or purchasing credits or allowances under a potential future trading program.

11. The Clean Power Plan could force AEPCO to commit to curtailing coal and even gas-fired generation or even retiring some or all of its steam units by 2022 to comply with the Clean Power Plan. AEPCO will need to make planning and resource allocation decisions long before Arizona adopts its state plan implementing the Clean Power Plan, EPA approves or disapproves such a plan, and even before EPA's proposed Federal Plan is finalized. Similarly, unless this Court grants relief, it is likely that AEPCO must make such decisions before this litigation is resolved. Because AEPCO must make these business decisions almost immediately to prepare to comply with the Clean Power Plan, the Clean Power Plan will have imminent and irreparable economic consequences for AEPCO if it is not enjoined during the pendency of the litigation and any compliance date extended. Absent such relief, AEPCO must comply with the Clean Power Plan regardless of whether it is ultimately found to be legal and this result works an extreme and unjust hardship on AEPCO, its members, and their members.

Introduction to AEPCO and its Generating Units

12. In support of AEPCO's generation services for its Class "A" members, AEPCO has built the Apache Generating Station in Cochise, Arizona, which consists of Steam Unit 1, a 72 MW natural gas fired steam unit built in 1963; Steam Units 2 and 3, a pair of 175 MW coal-fired steam units (with natural gas dual fire capability) built in 1978 and 1979 that presently generate the bulk of AEPCO's power; Gas Turbine 1, a 10 MW combustion turbine built in 1964 that can operate in semi-combined cycle mode with Steam Unit 1; Gas Turbine 2, a 20 MW gas or oil-fired combustion turbine built in 1972; Gas Turbine 3, a 65 MW gas-fired combustion turbine built in 1975; and Gas Turbine 4, a 38 MW gas or oil-fired combustion turbine built in 2002. The Apache Generating Station has a total net generating capability of 555 MW.

13. In response to the Regional Haze Rule, AEPCO has already committed to upgrading Steam Unit 1; converting Steam Unit 2 from dual coal/natural gas-fired operation to exclusively natural gas-fired operation except in the event of emergency; and to installing upgraded low NO_x burners, upgrading SO_2 scrubbing and installing selective non-catalytic reduction ("SNCR") on Steam Unit 3. This commitment will cost AEPCO approximately $30 million in capital and increase fuel costs by approximately 25% over current levels of operation.

14. The additional cost of the Regional Haze Rule is further aggravated by the 111(d) Rule and its impact on AEPCO's coal generating units. Because of the relative age and design of its units, Apache's heat rates for its three major steam units range from 10,321 Btu/kWh to 10,671 Btu/kWh, the natural gas conversion of Steam Unit 2 will likely add 150 Btu/kWh to its heat rate in the future. Heat rate is a critical component to successful market participation and, while burning natural gas, these rates are higher than those found in modern natural gas combined cycle ("NGCC") units, which causes our energy prices to be out of alignment with the neighboring markets.

15. AEPCO's annual revenues were $170 million in 2013 and $181 million in 2014. AEPCO has approximately $186 million in debt secured by a mortgage with the Rural Utilities Service ("RUS") and the National Rural Utilities Cooperative Finance Corporation ("CFC"). As noted above, AEPCO must expend another $30 million for Regional Haze Rule compliance prior to December 5, 2017.

16. Under the terms of AEPCO's mortgage with the RUS, AEPCO must maintain its debt and certain other financial indicators to meet certain criteria. The RUS mortgage and related loan documents require AEPCO to design rates to generate revenues sufficient to pay all taxes, maintenance expenses, costs of electric energy and other operating expenses, and to maintain, on an average of

the two best years out of the last three years, a Times Interest Earned Ratio of not less than 1.05 and a Debt Service Coverage Ratio of not less than 1.0. If AEPCO fails to do so, this failure will result in a default on the mortgage and immediate acceleration of the full $186 million in secured debt.

17. AEPCO has no shareholders. Because it is a not-for-profit cooperative, all of its costs must be paid for by its members. These costs include existing debt and new debt to pay for new resources. These costs also include all costs of generating energy and paying for pollution controls, including those contemplated by the Clean Power Plan.

The Clean Power Plan Rule

18. The Clean Power Plan requires that steam units, such as AEPCO's Steam Units 2 and 3, must achieve a carbon dioxide rate of no more than 1,534 lbs/MWh during the interim period of 2022-2029 and 1,305 lbs/MWh in the final period (2030 and beyond). 40 C.F.R. Part 60, Subpart UUUU, Table 1. Similarly, a stationary combustion turbine must achieve an interim rate of 832 lbs CO_2/MWh during the interim period and 771 lbs CO_2/MWh during the final period. *Id.*

19. In addition to the unit specific goals, the State of Arizona must develop a plan that ensures that total emissions of CO_2 from affected electric generating units during the interim period do not exceed 1,173 lbs/MWh on

average for all affected units and during the final period do not exceed 1,031 lbs/MWh on average for all affected units. *Id.* States have some flexibility in choosing their compliance paths, *see* Lisa Johnson Decl., ¶¶ 19-20, but state plans may not be finalized and approved by EPA until sometime in late 2018 or early 2019. States that fail to submit plans to EPA, or fail to submit approvable plans, will be subject to a Federal Implementation Plan ("Federal Plan").

20. As noted above, while the State of Arizona has some flexibility in devising its State Plan, if the State does not meet its reductions, the final compliance responsibility falls on AEPCO and other electric generating unit operators. 40 C.F.R. § 60.5885.

21. EPA's proposed Federal Plan states that EPA "intends" to allocate emissions allowances based on 2012 generation rates, but the final decision is deferred to future years. AEPCO's Steam Unit 1 would receive essentially no allowances if 2012 generation is used as the basis for allocation. EPA established a mass-based allocation of 36,032,671 tons in the interim period, compliance period 1. *See* proposed 40 C.F.R. § 60.15235(a) & Table 1. AEPCO's Steam Units 2 and 3 would receive at most their pro-rata share of 2012 generation, less 5% of the total (or 1,759,462 tons) for the renewable energy set aside, *see* proposed 40 C.F.R. § 62.16235(c) & Table 2, an additional 4,197,813 tons for the output-based set aside starting in the second compliance period, *see* proposed §

62.16235(d) & Table 3, and an additional 1,719,618 tons for the proposed Clean Energy Investment Program early action set aside, *see* proposed § 62.16235(e) & Table 4. Because AEPCO represents approximately 4% of 2012 affected generation in Arizona, AEPCO's allocation would be essentially 0.04 * (36,032,671 – 1,759,462 RE set aside – 1,719,618 CEIP set aside), or 1,627,659 tons. AEPCO cannot feasibly operate if its emissions are so limited.

The 111(d) Rule's Effect on AEPCO

22. AEPCO cannot comply with the Clean Power Plan as published on a rate basis. If a rate-based plan is implemented by Arizona, AEPCO does not have the ability to achieve the rate-based plan through any combination of its existing affected units and also meet its contractual load obligations to its members. For example, ST1 operates at approximately 1,460 lb/MWh, higher than the 832 or 771 lbs/MWh EPA authorizes for NGCC units under either the interim or final goal periods. Similarly, ST2 is expected to operate between 1,300 and 1,400 lbs/hr after its natural gas conversion. This rate is similar to the 1,534 lb interim rate for steam units, but well above the 1,305 lb final rate. Finally, ST3 operates at well over 2,000 lb/MWh, well above either the interim or final rates.

23. If a mass-based plan is implemented, and allocated as EPA has suggested in the proposed federal plan, AEPCO will receive an allocation of approximately 1.2 million tons CO_2 in 2022. With such an allocation, AEPCO

could only meet between 35 and 70 percent of the load before it must go to the market for either allowances or additional energy. The amount of load AEPCO could serve would decline thereafter as the number of allowances allocated to AEPCO declines.

24. AEPCO is a generation and transmission cooperative regulated by the Arizona Corporation Commission ("Commission"). AEPCO is required to act reasonably and prudently, subject to Commission review and oversight if it is to cover its cost pursuant to Arizona Administrative Code Section R14-2-1808-A. Purchasing between 35 and 60 percent of energy requirements on the market (either as allowances to run existing units or as energy) would not meet the prudency requirements of either AEPCO's members or of the Commission. Therefore, AEPCO must construct substantial new resources or purchase additional existing resources to comply with the Clean Power Plan.

25. While the Clean Power Plan creates an incentive to construct renewable resources, renewable resources cannot provide dynamic loading necessary to maintain AEPCO's transmission network.

26. AEPCO has no choice but to consider buying an existing NGCC unit(s) or building new NGCC unit(s) at Apache Generating Station or elsewhere. Whether an existing NGCC unit is available, "prudent" and able to support AEPCO's transmission network is unclear and subject to significant regulatory

uncertainty, both in terms of ability to run to meet AEPCO's needs in light of the Clean Power Plan and approvability by the Commission.

27. AEPCO therefore has determined that the most "prudent" course at this time, prior to final promulgation of the federal or state plan, is to add at least 211 MW of NGCC generation at Apache Generating Station. This addition should preserve the transmission network while meeting immediate generation needs. It is not sufficient, however, to carry AEPCO through the Clean Power Plan's interim period or final periods, when the goals become much more stringent. Adding a larger unit, or adding renewable energy or additional small units to meet load obligations under the Clean Power Plan, would further increase the cost and impact on AEPCO, its members, and their members.

28. Assuming the purchase of a new 211 MW NGCC unit to help ensure adequate load and network support, AEPCO has estimated a capital cost of $261 million. This will result in an annual compliance cost increase of tens of millions of dollars for AEPCO's members. This annual cost includes the capital cost of the new unit, fuel, the operational and maintenance costs, and the costs of retiring existing coal assets (ST3, coal handling equipment, ash disposal ponds, etc.) displaced by the new NGCC unit. The net effect would be a capacity cost increase of greater than 50%.

29. As a prudent operator, AEPCO will need to take steps immediately to ameliorate the cost consequences for its members. Because the Clean Power Plan will eliminate coal operation of ST3 by 2029 (because the allowable capacity factor is so unfavorable), AEPCO will need to retire substantial coal assets prior to the existing 2035 date, which is the current contract termination date for the two major steam units. If AEPCO waits for the State Planning process, which may not reach conclusion until September, 2019, AEPCO would be forced to recover the entire accelerated depreciation and decommissioning of the existing coal assets in only 9 years or less, at substantial cost to its members. Therefore, AEPCO needs to file as soon as possible for regulatory relief with the Commission to recognize the early retirement of the coal assets and spread the cost over the 2016 to 2028 period, which would help level (but not eliminate) the cost impact on its members. This means *immediately* undertaking the cost and expense of preparing a rate case. Even assuming the more favorable regulatory treatment discussed in this paragraph, the immediate cost to AEPCO members would be at least $3.7 million/year in 2016, increasing in subsequent years.

Additional Impacts

30. AEPCO directly and indirectly employs over 230 people, and it requires hundreds of additional skilled contractors that work at the plant during maintenance outages and capital project implementation. Between 300 and 550

contractors worked at Apache Generating Station during maintenance outages from 2013 to 2015. If AEPCO is forced to close Apache Generating Station or curtail its operations to comply with the 111(d) Rule, it will result in substantial lay-offs. Cochise County will also suffer economically painful consequences due to those layoffs and to the reductions in critical tax revenue. It is important to understand that the total job losses to the Cochise County economy would be greater than just the direct job loss at Apache Generating Station due to indirect and induced effects. Indirect effects refer to jobs that would be lost due to a cessation of business-to-business transactions between AEPCO and its suppliers. Induced effects refer to jobs that would be lost as a result of the decline in household earnings.

31. In summary the loss of jobs associated with the potential closure of the coal units at Apache Generating Station could well be greater than the total annual job losses countywide that have persisted over the past seven years (effectively doubling Cochise County's current annual job loss rate) and would further delay recovery of the Cochise County labor market.

32. AEPCO is the second largest property taxpayer in Cochise County, paying more nearly $3 million in property taxes in 2015. AEPCO's paired transmission cooperative, Southwest Transmission Cooperative, Inc., pays an additional $2.3 million in property taxes.

33. The premature closure of Apache Generating Station's key generating assets would jeopardize electric reliability in Southern Arizona. These units are utilized year-round to provide necessary dynamic voltage support and to prevent transmission system instability in the area. The surrounding transmission system has been designed around Apache Station, and displacing Apache resources would cause untenable voltage decline of various transmission elements and physical inability to import required power resources for our customers at the required levels.

34. AEPCO must make decisions on the future of Apache Generating Station in the very near future. It must decide now whether to spend the $30 million for Regional Haze Rule compliance. AEPCO cannot in good conscience choose to spend this money if it cannot recover the investment through rates because the underlying Steam Units 2 and 3 would be forced to shut down shortly thereafter. Similarly, AEPCO cannot recover sufficient costs in the period between now and 2022 to allow installation of these controls.

35. In the Mercury and Air Toxics Rule litigation, no stay was granted and, as a result, AEPCO incurred and will continue to incur substantial expenses to comply with that rule, even though the Supreme Court ultimately determined that the rule was not promulgated in accordance with the Clean Air Act. As in the MATS Rule, AEPCO must make compliance decisions within the next few

months that cannot be deferred if it is going to comply with the Clean Power Plan. Therefore, in order to prevent irreparable harm to AEPCO that is unlikely to ever be recovered from EPA, the federal government, or its rate payers, a stay needs to be granted until AEPCO's compliance obligations are clear and appropriate asset and power supply planning can occur.

Pursuant to 28 U.S.C. § 1746, I declare under the penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Executed: October 14, 2015

By: ______________________
Patrick F. Ledger

ATTACHMENT I

TO

MOTION OF UTILITY AND ALLIED PETITIONERS FOR STAY OF RULE

Declaration of Robert N. McLennan (Oct. 12, 2015)

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

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION, *et al.*,

Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,

Respondent.

No. ______________

DECLARATION OF ROBERT N. MCLENNAN OF MINNKOTA POWER COOPERATIVE IN SUPPORT OF MOTION TO STAY

I, Robert N. McLennan, declare:

1. I am President and CEO of Minnkota Power Cooperative, Inc. ("Minnkota"). In this capacity, I am responsible for the day-to-day oversight of more than 400 employees at the corporate office in Grand Forks, North Dakota and at the Milton R. Young Station ("Young Station") in Center, North Dakota, and over 1200 MW of generating resources serving an annual peak load of 960 MW.

2. I have been President and CEO of Minnkota since 2011. I am a graduate of the University of Jamestown in Jamestown, North Dakota. I have dedicated my 22-year career to serving the electric cooperative industry, specifically focusing on the areas of environmental affairs, member relations and public outreach. Prior

to joining Minnkota, I was employed by Tri-State Generation & Transmission Association, an electric generation and transmission ("G&T") cooperative based in Colorado, as senior vice president of external affairs and member relations. I also worked for the National Rural Electric Cooperative Association ("NRECA") as director of environmental affairs. I am currently Chairman of the Board for the Lignite Energy Council, and a member of the Board of Directors BNI Coal, Grand Forks Region Economic Development Corporation and the University of North Dakota's School of Engineering and Mines.

INTRODUCTION TO MINNKOTA AND ITS GENERATING RESOURCES

3. Minnkota is a non-profit wholesale electric G&T cooperative headquartered in Grand Forks, N.D. Minnkota recently had its 75th anniversary, beginning its operation in 1940. Eleven member-owned distribution cooperatives located in eastern North Dakota and northwestern Minnesota receive their electric energy from Minnkota under a contractual relationship that extends through 2055. In addition, Minnkota serves as the operating agent for Northern Municipal Power Agency ("NMPA"), a municipal joint action agency that serves as an energy supplier for 12 municipal utilities located within the Minnkota service area. In total, the Minnkota/NMPA "Joint System" provides electricity to more than 143,000 residential and commercial member consumers spanning over 34,500 square miles.

4. Minnkota and the Joint System have a diverse energy portfolio that includes coal-fired and renewable wind generation. That portfolio includes 705 MW of lignite coal generation at the Young Station (comprising two generating units, one of which is held by an identically owned affiliate, Square Butte Electric Cooperative), 128 MW of lignite coal generation at the Coyote Station (which is co-owned), 217.5 MW of wind generation from the Ashtabula Wind Energy Center, 139.5 MW of wind generation at the Langdon Wind Energy Center and 109 MW of hydropower generation from the Garrison Dam owned by the Federal Government and administered by the Western Area Power Administration. Lignite coal generation provides the majority or “baseload” of electricity for Minnkota and the Joint System.
5. Minnkota’s primary generation resource is the Young Station, a mine-mouth power plant located near Center, North Dakota, with two generating units providing 705 MW of energy fueled by lignite coal. Unit 1, which began producing electricity in 1970, is owned and operated by Minnkota and has the capacity to produce 250,000 KW of electricity. Unit 2, with a 455,000 KW generating capacity, began producing electricity in 1977. Unit 2 is owned by another electric cooperative and is operated by Minnkota. The output from Unit 2 is purchased under contract by Minnkota which purchases approximately 355 MW and another utility currently purchases 100 MW, although 100% of the

Unit 2 generation will be purchased by Minnkota by 2026. The Young Station was constructed through a loan issued by the Rural Electrification Administration in 1966. The Station's energy powers farms, schools, businesses, taconite producers, paper and pulp mills, and other industrial facilities, as well as many residential homes. Over 160 employees work at the Young Station.

6. Minnkota's generation resources currently total more than 1,200 MW. Minnkota currently serves a peak load of approximately 960 MW that is recognized in the winter. According to recent studies, Minnkota's forecasted peak load will grow to 1,100 MW in 2030. Based on these calculations, there is no demand for additional generation capacity. It would be excessive and a misuse of members' capital for Minnkota to construct and/or acquire unnecessary surplus generation resources prior to 2030 given present generation resources available to Minnkota.

7. As a G&T electric cooperative, Minnkota typically serves the rural areas that because of population density are not as profitable as areas supplied by investor-owned utilities. As explained more fully in the Declaration of Kirk Johnson, filed on behalf of NRECA, the principal purpose of an electric cooperative is to provide affordable and reliable electricity to the underserved rural areas and oftentimes lower-income populations. Consistent with its status

as a rural electric cooperative, Minnkota's mission is to provide electricity at the best energy value in the region. Through its generation resources, Minnkota currently has some of the most competitive wholesale electric rates in the country.

8. Being a not-for-profit cooperative also means Minnkota's member consumers directly shoulder the costs of Minnkota's energy infrastructure. Because Minnkota serves rural customers, there are also less consumers per mile of electric line to shoulder that burden. If Minnkota is required to build additional generation or purchase otherwise unnecessary power to comply with EPA's new carbon dioxide (CO2) emissions limits for existing sources, discussed below, this will directly result in higher electricity rates to Minnkota's member consumers, burdening low-income consumers.

THE 111(D) RULE

9. On August 3, 2015, the United States Environmental Protection Agency ("EPA") signed the final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (the "Rule").

10. As explained more fully in the Declaration of Lisa Johnson, filed on behalf of Seminole Electric Cooperative, the Rule requires a nationwide 32-percent reduction in (CO_2) emissions from 2005 levels required by 2030. The Rule achieves those reductions through uniform CO_2 emission performance rates

EPA has imposed on two subcategories of existing power plants (coal- and natural gas-fired units) and state-wide rate- or mass-based emissions goals that are formulated from the subcategory performance rates. States are required to formulate state plans for compliance and submit those plans to EPA for approval. Although states must plan for compliance, affected units like the Young Station are ultimately responsible for compliance with the interim and final goals established in the Rule. By EPA's own admission, existing units cannot meet the new performance rates though any technological or operational changes at the unit without curtailing their generation or shuttering their plants, shifting generation to lower-emitting sources, and/or purchasing credits or allowances under a potential future trading program.

11. For existing coal-fired units like the Young Station, the uniform performance rate that must be achieved is 1,305 lbs CO_2/MWh-net. That performance rate was used by EPA to calculate state-wide emission goals, and individual coal-fired units must comply with that rate or its equivalent by 2030. The Young Station currently emits 2,400 lbs CO_2/MWh-net. The Young Station cannot achieve the new performance rate – there is no technology or operational means available to reduce CO_2 rates at the Station to levels low enough to comply with that standard, short of curtailing generation from or closing one or both units. The same is true for Minnkota's other coal-fired resources.

12. The Young Station would fare no better under EPA's state-wide goals. North Dakota must achieve one of the steepest CO_2 emission reductions required under the Rule. The Rule requires a 45-percent reduction in the state's carbon dioxide emissions from the 2005 levels by 2030. North Dakota's final rate-based CO_2 emission performance goal for 2030 is 1,305 lbs CO_2/MWh (identical to the coal-fired performance rate), and its mass-based goal is 20,883,232 short tons of CO_2.

13. Although the *final* state goals are not effective until 2030, the rule establishes what EPA calls a "glide path" with increasingly stringent interim emission reduction requirements, average interim performance rates, and goals for the 2022 to 2029 compliance period, in addition to the 2030 final performance rates and goals. As implemented over time, and depending on whether North Dakota implements a rate-based or mass-based state model, Minnkota will need to achieve a CO_2 reduction, respectively, of 36.7% or 30.8% by 2025; 41.7% or 34.9% by 2027; and 44.9% or 37.4% by 2030.

THE RULE'S IMPACT ON MINNKOTA

14. Because the Young Station cannot satisfy the Rule's unit-specific performance rate or state-wide goals, Minnkota simply cannot meet the Rule's specified emission rates or mass-based goals without substantial modifications to its current generation portfolio. To comply, Minnkota would need a combined

approach of reducing its generation at its three coal generating resources, perhaps shuttering the Young Station completely, coupled with procurement of a substantial quantity of additional wind resources and the likely construction of gas-fired generation capacity. Minnkota must make these plans immediately, without full information on what type of state implementation plan North Dakota will adopt, and potentially spend hundreds of millions of dollars on unnecessary generating resources. In support of these statements, this Declaration will focus on three of the areas posing significant harm to Minnkota, which will be real, immediate and irreparable should the Rule be overturned after not having been stayed pending review.

Impending Capital Investments

15. The first area that puts Minnkota at real risk for irreparable harm concerns the upcoming required capital investments at the Young Station. Currently, Minnkota has scheduled maintenance and capital projects at the 250 MW Unit 1, totaling more than $60 million over the next 5 years. The final Rule requires a reduction of carbon emissions in North Dakota by 29.4% or 23.7%, depending on whether the state adopts a rate- or mass-based approach, by 2022. The state likely will not be determine its final approach until late 2018 or early 2019, because states are permitted under the final Rule to seek an extension to

September 6, 2018, to submit a final state plan to EPA for approval. *See* Lisa Johnson Decl., ¶ 21.

16. Given the legal uncertainty surrounding the Rule, Minnkota is faced with the decision of whether or not to make substantial investments in a coal-fueled asset that may or may not be able to continue operating beyond the year 2022, the initial "cliff" of the Rule. Absent the Rule, these investments will be capitalized and paid for by Minnkota's 143,000 member consumers over the next 30 years or longer. However, the asset may need to be shut down prematurely to comply with the Rule.

17. At present, Minnkota cannot commit $60 million to an asset that cannot continue running for the life of the investment; to do so would cause great harm, without taking into account the $425 million investment for environmental upgrades already made to the Young Station in the last few years.

18. On the other hand, if Minnkota does not invest the $60 million at the Young Station due to an uncertain future, and the Rule is subsequently overturned, Minnkota would suffer irreparable harm by diminishing both the efficiency and the reliability of its baseload asset as a result of not making these investments. Minnkota cannot wait for a final state plan or the outcome of this litigation to decide whether to make these critical capital investments.

New Generation

19. The second issue facing Minnkota is the need for more generation capacity to comply with the Rule. This need stems from the Rule's requirement to reduce coal-fired generation and the very real possibly that one or both units at the Young Station will have to be closed to comply with the Rule. Although Minnkota currently has renewable and low-emitting wind generation resources, and would need to procure more to comply with the Rule, Minnkota likely would also need to construct a new natural gas resource to replace baseload generation from the coal-fired Young Station. Wind generation is too variable to rely on for baseload generation and must be backstopped by other types of generation, like natural gas, to be run during periods when the wind is not blowing.

20. In recent years, Minnkota has evaluated the feasibility of adding natural gas capacity and has determined that it will take as long as 7 years to create a site plan, complete permitting, finalize technology studies, conduct transmission and interconnection studies, complete regulatory filings, confirm fuel source, construct a pipeline, and more to have an operational resource. This effort would need to commence immediately in order to comply with the Rule.

21. Within the next 2 to 3 years, Minnkota would need to spend approximately $8 million on just the preliminary portions of this work. While this may be

necessary to comply with the Rule, this option is particularly harmful because Minnkota already has excess generation projected until 2030, and it does not need an additional generation resource. The construction of a natural gas facility would be done only to comply with the Rule.

22. The total cost of adding natural gas capacity is expected to be at least $300 million. Minnkota would need to obtain that financing, starting in the next 2 years.

23. Further compounding the risk of irreparable harm to Minnkota is the amount of debt Minnkota and its affiliates presently carry on both units at the Young Station, totaling $800 million, $425 million of which was to cover the cost of state-of-the-art environmental upgrades made by Minnkota to achieve compliance with other EPA rules between 2007 and 2011. If required to shut down one or both units at the Young Station prematurely, plus build new natural gas generation to make up for the lost generation from the Young Station, our member consumers will be required to pay the substantial debt on the existing units and the very expensive costs for constructing a new resource. If Minnkota undertakes this option for compliance and the Court later overturns the Rule, Minnkota and the 143,000 member consumers in the Joint System will be left with debt, surplus generation capacity, and higher rates. In other words, they will be irreparably harmed.

New Wind Purchases

24. The final issue facing Minnkota also relates to the need for additional capacity to comply with the Rule. While Minnkota continues to evaluate its options for compliance, under either a mass-based or rate-based calculation it is clear that Minnkota will be forced to procure additional wind energy. To have the additional energy available for compliance by the 2022 time frame, Minnkota would need to secure substantial wind energy by entering into long-term purchase power agreements within the next 2 years during the pendency of the Court's deliberation.

25. As indicated above, Minnkota has excess generation, a significant portion of which is the 357 MW of wind energy resources acquired between 2007 and 2009. Adding additional wind energy will be solely an expense to comply with the Rule. Furthermore, Minnkota would need to start planning and permitting the construction of likely substantial transmission investments necessary to support the additional wind energy in a state that already has endured the addition of huge quantities of wind generation of the last decade and that has already maximized the existing infrastructure. That additional infrastructure would cost Minnkota (and by extension its member consumers).

26. If a stay were denied and if the Rule were ultimately vacated by the Court, Minnkota would have already entered into long-term contracts for the purchase

of wind-generated energy that are not needed. Minnkota would likely have also made additional transmission investments that would not be necessary. Minnkota's member consumers would be stuck paying for unnecessary wind generation and transmission through higher electricity rates for many years to come.

CONCLUSION

27. As a relatively small non-profit cooperative, Minnkota simply cannot justify incurring the debt set out above without putting its financial commitments and financial covenants in serious jeopardy. All costs incurred for compliance with the Rule will be borne by Minnkota's 143,000 member consumers. Unless the Rule is stayed pending judicial review, Minnkota must act quickly and make these irrevocable decisions, causing Minnkota, the Joint System and their member consumers to suffer irreparable harm. If the Rule is later overturned, Minnkota will already be committed to substantial investments in unnecessary power generation resources that are not presently needed. This runs counter to the very purpose for which rural cooperatives were established – the provision of reliable and affordable energy to rural customers.

Pursuant to 28 U.S.C. § 1746, I declare under the penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Executed: October 12, 2015

By: ______________________

Robert N. McLennan
President and CEO
Minnkota Power Cooperative, Inc.

ATTACHMENT J

TO

MOTION OF UTILITY AND ALLIED PETITIONERS FOR STAY OF RULE

Declaration of Kimball Rasmussen (Oct. 13, 2015)

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

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION, *et al.*

Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,

Respondent.

No. ____________

DECLARATION OF KIMBALL RASMUSSEN FOR DESERET GENERATION & TRANSMISSION CO-OPERATIVE IN SUPPORT OF MOTION TO STAY

I, Kimball R. Rasmussen declare as follows:

Introduction

1. I am the President and Chief Executive Officer of Deseret Power ("Deseret") and have been employed in that capacity since 1999.

2. Deseret is a Utah non-profit corporation comprised of six members. Its members are rural electric cooperatives that provide retail electric service in rural areas of Utah and neighboring states. Deseret owns and operates electric generation and

transmission facilities for the benefit of its members. Deseret also provides significant "baseload" (around-the-clock) electric energy to public utilities operating throughout the Western United States. Deseret's principal electric generating asset is the Bonanza Station, a 485 MW coal-fired electric generating unit located near Vernal, Utah. Bonanza represents over two-thirds of Deseret's entire electric generation resource.

The Clean Power Plan Imperils the Future Operation of the Bonanza Station

3. The Clean Power Plan ("CPP") establishes carbon dioxide ("CO_2") emission standards for coal-fired electric generating units. Under those standards, coal-fired units cannot emit more than 1,534 pounds CO_2 per megawatt hour ("lbs/MWh") for the interim the period 2022-29 and more than 1,305 lbs/MWh as a final limit thereafter. The Bonanza Station cannot meet these limits as, in its entire 30-year history, it has never operated for any length of time below approximately 2,000 lbs/MWh. There exists no commercially viable technology which could be incorporated by Bonanza to reach EPA's limits.

4. EPA has established an alternative path by which the 47 states and three Native American tribal areas that are subject to the CPP may comply with the CPP's 1,534 and 1,305 lbs/MWh emissions standards. In theory, States and tribes can adopt one of two types of budgets that fossil-fueled electric generating stations in the state or tribal area would have to meet. One type of budget is an emissions rate budget, where EPA set individual state-by-state and tribal-area-by-tribal-area CO_2 emissions

rates that electric generation resources in aggregate within each state and tribal area would have to meet. The other type of budget is a "mass based" budget which sets a limit on the number of tons of CO_2 emissions that all fossil-fueled-electric generating units within the state or tribal area can in aggregate emit.

5. One of the tribal areas for which EPA has set budgets is the Uintah/Ouray Reservation (hereafter "Reservation") in northeast Utah. EPA takes the position in the CPP that the Station is located on lands within the exterior boundaries of the Reservation and therefore is subject to the emission budgets that EPA set for that Reservation.

6. The Bonanza Station, however, cannot meet either the rate-based or mass-based budgets that EPA set for the Reservation. The rate-based budget for the Reservation is the same 1,534/1,305 lbs/MWh emissions rate that EPA set for coal-fired generating units in general.

7. The Bonanza Station is the only generating unit of any sort on the Reservation; it has no ability to aggregate its emissions with any other facility to meet the rate-based CPP emissions rates. The only way Bonanza and the Reservation could comply with these rates would be for Bonanza to close.

8. The Bonanza Station also cannot comply with the mass-based budget. The mass-based budget that EPA set for the Reservation beginning in 2022 represents less than 80 percent of the CO_2 emissions that the Bonanza Station emits in a typical year. Thus, Bonanza can meet the "mass-based" limit only by dramatically reducing

hours of operation, thereby operating more than 20 percent less than it currently operates. But since Bonanza is a "baseload" plant, providing reliable round-the-clock service, the only way the Station could comply with the CPP is to cease operating as a baseload plant.

9. If the Bonanza Station is forced to cease operating as a baseload plant, and Deseret is forced to replace the lost baseload generation as a result, the average residential, agricultural, and small commercial customer that receives service in one of the six rural service territories served by Deseret's member co-operatives would see rate increases that could quickly accumulate to over 40 percent or more in their electricity bills.

10. In theory, if the Uintah/Ouray tribal government entered into an agreement with other states providing for the trading of emissions allowances, Bonanza could continue to operate as a base load plant by purchasing allowances from a generating station located elsewhere that "over-complied" with the CPP. The Ute Tribe, however, indicated in their comments on the proposed CPP that it opposes any cross-border or inter-jurisdictional emissions trading.

The Clean Power Plan Imperils Deseret's Current Planning and Access to Long-term Financing

11. The fact that the only scenario under which the Bonanza Station, beginning in 2022, can stay open is to reduce generation and cease operation as a baseload facility is affecting Deseret's current decision making.

12. A portion of the output from the Bonanza Plant is sold under long-term bilateral contracts with utilities in Utah and other states that depend on the operation of the plant as a baseload facility as an integral part of their portfolio of baseload, intermittent, and peaking resources. A number of these contracts are currently set to expire during the years 2020-2025. Given the very long lead times involved in electric utility planning and resource acquisition, negotiations are already underway as to the price and other rates or terms for extension periods under these contract arrangements (the "Renewing Contracts").

13. With the publication of the CPP, however, Deseret is forced to assume that it cannot provide baseload power under any Renewing Contracts, or to assume a dramatic decrease in available baseload capacity to continue serving the Renewing Contracts and/or its other baseload requirements. Because baseload resource development typically takes more than 6 years to plan, permit, construct, and begin operations at utility scale, the purchasers under the Renewing Contracts must decide in the very near future whether to stay with Bonanza in the future as a non-baseload (or "partial" baseload) facility or purchase/construct an alternative baseload resource.

14. The purchasers under the Renewing Contracts inform Deseret that they have already begun looking elsewhere for potential alternative baseload resources.

15. Deseret must be in a position, within no more than 18 to 24 months from now, to contractually bind itself to the quantity and availability of baseload

resource which the Renewing Contracts will be able to draw upon during any renewal period from and after 2022.

16. Deseret also supplies baseload power and energy to its six members, each of which is a rural electric distribution co-operative operating under "all requirements" type wholesale power agreements (the "All Requirements Contracts").

17. Deseret's All Requirements Contracts are the primary collateral, and therefore the principal component of long-term financing available to Deseret for capital to maintain, repair, and make permitted capital improvements at the Bonanza Station.

18. Deseret's All Requirements Contracts are currently set to expire at the end of 2025. Deseret is in discussion with all of its rural electric cooperative members to renew and extend the All Requirements Contracts through a very long period until 2045 and beyond. It is very atypical and potentially debilitating to Deseret's ability to obtain needed capital financing for an operating generation & transmission cooperative such as Deseret to have member requirements contracts which expire anytime sooner than 20 to 40 years into the future.

19. Deseret's member systems must perform adequate due diligence including submitting sufficient analysis and support to the state public service commissions in order to justify and obtain consent to extend the All Requirements Contracts.

20. Deseret cannot reasonably provide long-term integrated resource plan(s) and associated backup to support the long-term extension of these All Requirement Contracts in the absence of reasonable certainty that its primary baseload resource, the Bonanza station, will be available to operate and provide adequate baseload generation supply to meet the all-requirements needs of its members beyond the current expiration of those contracts in 2025.

21. By the same token, it is not tolerable for Deseret to delay extending its All Requirements Contracts beyond the next 12 to 18 months. Any protracted delay will seriously risk Deseret's ability to obtain financing on reasonable commercial terms for long-term project needs at Bonanza and on the balance of Deseret's system.

22. I, Kimball R. Rasmussen, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct.

Kimball R. Rasmussen

Dated: October 13, 2015

ATTACHMENT K

TO

**MOTION OF UTILITY AND ALLIED PETITIONERS
FOR STAY OF RULE**

Declaration of Kirk Johnson (Oct. 14, 2015)

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

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION, *et al.* Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, Respondent.	No. ______________

DECLARATION OF KIRK JOHNSON FOR THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION IN SUPPORT OF MOTION TO STAY

I, Kirk Johnson, declare:

1. I am Senior Vice President for Government Relations for the National Rural Electric Cooperative Association ("NRECA"). NRECA represents the national interests of rural electric cooperatives and the consumers they serve. As Senior Vice President for Government Relations for NRECA, I am responsible for the Association's overall response to legislative, regulatory, and judicial matters affecting the interests of electric cooperatives.

2. I have worked for NRECA for approximately 14 years. I received my BA from Concordia College in Moorhead, Minnesota, and attended graduate

school at the Hubert H. Humphrey Institute of Public Affairs at the University of Minnesota.

3. On August 3, 2015, the United States Environmental Protection Agency ("EPA") signed the final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units ("111(d) Rule").

4. I offer this declaration to accompany the declarations of NRECA members Arizona Electric Power Cooperative ("AEPCO") ("Ledger Decl."); Associated Electric Cooperative, Inc. ("Associated") ("Jura Decl."); Deseret Generation & Transmission Cooperative ("Deseret") ("Rasmussen Decl."); East Kentucky Power Cooperative ("East Kentucky") ("Campbell Decl."); Minnkota Power Cooperative, Inc. ("Minnkota") ("McLennan Decl."); San Miguel Electric Cooperative, Inc. ("San Miguel") ("Brummett Decl."); Seminole Electric Cooperative, Inc. ("Seminole") ("Lisa Johnson Decl."); and Tri-State Generation and Transmission Association, Inc. ("Tri-State") ("McInnes Decl."). This declaration provides background on the creation, operation, and financing of electric cooperatives in order to explain why the 111(d) Rule will have a disproportionate impact on rural electric cooperatives and the low-income consumers they serve.

NRECA and Its Members

5. NRECA was formed in 1942 by rural electric cooperative leaders to represent the interests of electric cooperatives before Congress and Federal Agencies. Today, NRECA represents more than 900 not-for-profit, member-owned rural electric cooperatives.[1] NRECA's members include 838 local distribution cooperatives that provide electricity directly to member-consumers and 66 generation and transmission ("G&T") cooperatives, which generate and transmit wholesale power to the majority of the distribution cooperatives.[2] The G&Ts are owned by the distribution cooperatives they serve.

6. The history of, and purpose for, rural electric cooperatives traces to the New Deal era. They were established to provide reliable and affordable electricity to rural homes, farms, and businesses by purchasing electric power at wholesale prices and delivering it directly to the consumer without profit. In 1935, only 10 percent of farms had electric service. Investor-owned utilities had generally declined to provide electric service to rural areas due to high development costs owing mainly to the infrastructure required to supply electricity

[1] Depending on state law, electric cooperatives are defined as Electric Membership Corporations ("EMCs") or Electric Power Associations ("EPAs"). NRECA electric distribution members also include forty-four public power districts and municipal utilities.

[2] The remaining distribution cooperatives receive power directly from other generation sources.

to remote rural areas, coupled with the likelihood of low profit margins. As a result, rural customers were left without access to electricity.

7. To remedy that disparity, President Roosevelt established the Rural Electrification Administration ("REA") to encourage the generation, transmission, and distribution of electricity to rural areas. Subsequently, Congress passed the Rural Electrification Act of 1936, 7 U.S.C. § 901, *et seq*. The REA administered low-interest and long-term loans to rural electric cooperatives to assist them as they build infrastructure and improve electric service, and it provided cooperatives technical, managerial, and educational assistance. The REA was replaced in 1994 by the U.S. Department of Agriculture's Rural Utilities Service ("RUS"). Most of the electricity service in rural America today is provided by not-for-profit rural electric cooperatives originally founded with REA/RUS funds, and RUS continues to administer loans for the majority of electric cooperatives.[3] I note with some concern, however, that the current Administration has proposed significant restrictions for such loans in recent years.

8. All of the cooperatives are incorporated as private entities and have legal obligations to provide reliable electric service to their consumer-members. NRECA members provide electricity to approximately 42 million member-

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[3] For information on the cooperatives' current RUS loans, *see* Brummett Decl., ¶¶ 6, 13; Campbell Decl., ¶ 25; Ledger Decl., ¶¶ 15-16.

consumers in 47 states, comprising 12 percent of U.S. electric customers. Cooperatives serve 19 million businesses, homes, schools, churches, farms, irrigation systems, and other entities in 2,500 of the 3,141 counties in the United States. They own and maintain 42 percent of the nation's electric distribution lines. All but three of the G&Ts and distribution cooperatives qualify as small businesses according to the U.S. Small Business Administration.[4]

9. In short, rural electric cooperatives provide critical electric service to rural and low-income areas that investor-owned utilities typically declined to serve. To illustrate the dichotomy, rural electric cooperatives serve an average of only 7.4 consumers per mile of line, compared to an average of 34 customers per mile of line for the investor-owned electric utilities and 48 customers per mile for the municipal electric utilities. That number can be much lower. As pointed out in the respective declarations of Michael McInnes and Lisa Johnson, for example, Tri-State's members serve an average of less than five consumers per mile, and some of Seminole's member distribution cooperatives serve as few as 4.6 consumers per mile of electric line.[5] Fifty cooperatives have fewer than two consumers per mile of line (mostly in the Dakotas, Montana and Minnesota). Two with the lowest

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[4] *See, e.g.*, Brummett Decl., ¶ 4; Ledger Decl., ¶ 6.

[5] Lisa Johnson Decl., ¶ 8; McInnes Decl., ¶ 2; *see also* Jura Decl., ¶ 13 (Associated's member cooperatives have an average of only 6.04 customers per mile of line).

density areas are FEM Electric Association in South Dakota at less than one consumer per mile, and Cavalier REC in North Dakota at 1.02 consumers per mile of line.

10. The relatively small number of consumers per mile of line served by rural electric cooperatives has direct bottom-line effects. For example, rural electric cooperatives collect annual revenues of approximately $16,000 per mile of line, while public or municipally owned utilities collect $113,000 per mile of line. As a result, rural electric cooperatives have relatively fewer consumers and financial resources. Accordingly, the substantial challenges facing other electric utilities within the sector for financing large infrastructure projects are only amplified for rural electric cooperatives.

11. Rural electric cooperatives provide affordable electric power to customers who are often economically disadvantaged.[6] America's electric cooperatives serve more than 90 percent of the persistent poverty counties across the country.[7] The customers of nine out of ten electric cooperatives have average

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[6] *See, e.g.*, Brummett Decl., ¶¶ 20-23; Campbell Decl., ¶ 11; Lisa Johnson Decl., ¶¶ 8, 11-14; Jura Decl., ¶¶ 10-11; McInnes Decl. ¶ 4, Rasmussen Decl., ¶ 9.

[7] USDA Economic Research Service (ERS) has defined counties as being persistently poor if 20 percent or more of their populations were living in poverty over the last 30 years (measured by the 1980, 1990 and 2000 decennial censuses and 2007-11 American Community Survey 5-year estimates). Using this definition, there are currently 353 persistently poor counties in the United States

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household incomes lower than the national average. One in six consumers served by an electric cooperative lives at or below the poverty line. Rural electric cooperatives were formed specifically to provide reliable electric service to those member-consumers at the lowest reasonable cost.

12. Rural electric cooperatives also differ from investor-owned and municipally-owned utilities in the way they are governed. They are incorporated in the states in which they reside, and they are owned and democratically governed by their member-consumers through boards of directors that are elected by, and come from, their membership. The boards set policies and procedures that are then implemented by cooperatives' professional staff. This anchors them to the communities.

Cooperative Capital Project Planning and Financing

13. Cooperatives must engage in capital project planning years before making any new investments. Building new generation resources and related infrastructure in particular requires many years of advance planning. To construct

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(comprising 11.2 percent of all U.S. counties). The large majority (301 or 85.3 percent) of the persistent-poverty counties are rural (*e.g.*, non-metro), accounting for 15.2 percent of all non-metro counties. Persistent poverty also demonstrates a strong regional pattern, with nearly 84 percent of persistent-poverty counties in the South, comprising of more than 20 percent of all counties in the region.

a new power plant or renewable resource, cooperatives must create a site plan, apply for the necessary permits, finalize technology studies, conduct transmission and interconnection studies, complete regulatory filings, confirm the fuel source, construct or contract for pipelines to be built or capacity to be used, if needed, sign construction contracts, and construct the new resource.[8] For instance, Minnkota projects that it would take up to seven years to construct a new natural gas resource, Tri-State estimates that a new project could take anywhere from three to ten or more years to complete, and Seminole believes the planning process must begin six years before new generation resources are slated to come online.[9]

Planning for new generation is not the only advance decision cooperatives face. For example, Deseret is already negotiating its baseload power Renewing Contracts with utilities in Utah and other states, which must be complete within the next 18 to 24 months, and its All Requirements Contracts with its member cooperatives, which must be complete within the next 12 to 18 months.[10] Those decisions must be made *now*.

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[8] *See* McInnes Decl., ¶ 15.

[9] Lisa Johnson Decl., ¶ 26; McInnes Decl., ¶ 15; McLennan Decl., ¶ 20;; *see also* Campbell Decl. ¶ 22 (up to 10 years); Jura Decl., ¶ 26 (up to 7 years); Rasmussen Decl., ¶ 13 (typically, more than 6 years). In the case of mine-mouth power plants like San Miguel, the cooperatives must also plan years in advance for future mining operations or mine closure. *See* Brummett Decl., ¶¶ 4, 30-41.

[10] Rasmussen Decl., ¶¶ 12-21.

14. Cooperatives also must obtain financing for any capital expenditures. Financing poses a significant challenge for rural electric cooperatives. As described below, financing options for cooperatives are limited and can be more expensive than that available to other types of utilities, and any capital costs must be passed on to rural, low-income consumers through higher electricity rates.

15. G&Ts provide wholesale electricity to their member distribution cooperatives at rates that reflect their costs plus a small operating margin that serves as a cash reserve for unforeseen or unplanned events. Their wholesale rates cover only costs associated with debt service plus a small operating margin and do not include equity contributions to fund large capital projects. G&Ts therefore carry a large amount of debt relative to investor-owned segment within the electric utility industry because of how they must acquire capital. Specifically, G&Ts have no outside investors like the investor-owned utilities and thus do not have the option of acquiring capital through private equity. G&T financing also differs from that of the municipally owned utilities as they do not have access to municipal bonds. All G&T financing comes from issuing debt or from rates paid by consumers. There is no other source of capital for the G&Ts.

16. In the past G&Ts borrowed almost exclusively from RUS or one of two cooperative lending organizations that supplement RUS funds – the National Rural Utilities Cooperative Finance Corporation ("CFC") and CoBank, ACB

("CoBank").[11] The CFC is a member-owned, nonprofit cooperative organized in 1969 to raise funds from capital markets to supplement RUS loan programs. CoBank is a national cooperative bank and a member of the Farm Credit System, a nationwide network of banks and retail lending associations chartered to support the borrowing needs of U.S. agricultural interests and the nation's rural economy.

17. Increasingly, G&Ts have been forced to access the public and private capital markets due to loan restrictions imposed by RUS. For nearly a decade, RUS was prohibited from making loans for baseload generation sources such as coal, nuclear, or natural gas baseload generation units. The Administration's annual budget request has also proposed significant limitations on RUS loans. G&Ts have thus turned to the capital markets for financing. For those that have outstanding RUS obligations, G&Ts have worked to convert their existing RUS mortgages to RUS-approved indentures. Generally, an indenture is a form of mortgage that allows a borrower more flexibility in obtaining financing from non-governmental sources, provided that it meets certain agreed-upon financial requirements.

18. This access to private financing, however, comes with a higher cost as compared to costs associated with RUS loans. Moreover, because G&Ts are

[11] *See* Brummett Decl., ¶¶ 6, 13; Campbell Decl., ¶ 25; Ledger Decl., ¶¶ 15-16.

relatively smaller in size than investor-owned utilities and historically have had limited activity in the capital markets, G&Ts and their credit attributes are not as well known or understood by potential investors as compared generators within other electric utility segments. This lack of familiarity often results in a "story bond" premium being placed on G&T debt. A "story bond" is a bond with unusual characteristics that are unfamiliar or difficult to understand and in which investors are usually hesitant to invest. The term derives from the practical reality that the issuer must usually explain the "story" behind the bond's features in such a way as to convince the investor to buy it. A story-bond premium raises the costs of financing substantially.

19. G&Ts also generally have retained fairly low equity-to-total-capitalization ratios, often between 10 and 20 percent. Those low ratios at times affects credit analysis, including the assignment of credit ratings, which in turn affects the cost of capital and other aspects of a utility's operations. Because G&Ts are dependent on debt financing and lack any access to equity markets they must have access to these debt markets by maintaining sufficient credit ratings in order to fund capital expenditures. Large capital expenditures relative to the cooperative's total assets can cause significant deterioration in credit metrics making it more difficult, more expensive, or both to finance needed projects. If G&Ts are required to materially increase their capital expenditures to comply with

the 111(d) Rule, their equity-to-total-capitalization ratio will be adversely affected and will result in pressure on, and likely downgrading of, their credit ratings.[12]

20. Because G&Ts are not-for-profit, they must pass along capital costs directly to their member-consumers through increased rates.[13] The rural nature of electric cooperatives' business (and the small number of customers per mile of distribution line discussed above) means that fewer customers exist to share those costs.[14] Electric cooperatives' rural customers already spend more of their limited income on electricity than other electricity consumers, and they are accordingly disproportionately affected by rate increases.

21. Electric cooperatives may not, however, be free to raise rates to their consumers to pay for debt service associated with needed improvements. G&T boards must approve any rate increases in the first instance, and democratically-elected board members (who are also consumers) are traditionally reluctant to vote for a rate increase. In addition, cooperatives in twenty-three states are subject to rate regulation by state public utility commissions ("PUCs"); six G&Ts are subject

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[12] *See* Lisa Johnson Decl., ¶ 28; McInnes Decl., ¶ 7.

[13] *See* footnote 29, *infra*.

[14] *See* footnote 5, *supra*.

to the Federal Energy Regulatory Commission ("FERC") rate regulation.[15] An inability to raise rates could have serious consequences for cooperatives. For example, as AEPCO has described, the terms of its RUS mortgage and related loan documents require AEPCO to design its rates to generate sufficient revenue and to maintain certain financial health indicators, risking default and immediate acceleration of the full amount of its mortgage if those metrics are not satisfied.[16]

Overview of the 111(d) Rule

22. As explained more fully in the Declaration of Lisa Johnson for Seminole, the 111(d) Rule has the potential to drastically change the way that electricity is generated in this country.[17] The rule requires a sharp reduction in fossil fuel-fired generation beginning in 2022, with a 32-percent reduction in carbon dioxide (CO_2) emissions from 2005 levels required by 2030. To achieve that reduction, the 111(d) Rule imposes performance rates on two types of power plants: steam generating units (generally, coal-fired) and stationary combustion turbines (natural gas-fired). The performance rates are 1,305 lbs. CO_2/MWh-net and 771 lbs. CO_2/MWh-net, respectively.

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[15] *See* Ledger Decl., ¶ 29 (discussing the need to file for regulatory relief and prepare a rate case soon to spread the cost of stranded assets over as many years as possible).

[16] *Id*. ¶ 16.

[17] *See* Lisa Johnson Decl., ¶¶ 15-20.

23. The 111(d) Rule also imposes CO_2 emissions limits expressed via state-wide rate- or mass-based emission limits. The state-wide limits were calculated as a weighted average of each state's particular mix of fossil-fuel electric generating units in the baseline year 2012. States were affected differently by the final rule depending on their generation mix – generally, states that rely more heavily on coal-fired generation face the steepest emission cuts. States cannot change those limits or establish their own goals, but may adopt either a rate-based or mass-based approach to satisfying EPA's prescribed limits and can choose from a number of implementation paths set forth in the 111(d) Rule.[18]

24. Regardless of which compliance approach states choose, emission reductions from affected electric generating units – individually or in the aggregate – must achieve the equivalent of the EPA-specified CO_2 emission performance rates by 2030, expressed via the state-specific rate- or mass-based goals.

25. States must submit at least an initial state plan for compliance to EPA by September 6, 2016, with an option to seek an extension to September 6, 2018, to submit a final plan. It will not be clear what compliance methods will be ultimately adopted by a state – including whether a trading program will be established, the term (and affordability) of any such program, or whether that

[18] *See* Lisa Johnson Decl., ¶¶ 7, 19.

program will be acceptable to EPA – until the plan is finalized and approved by EPA sometime in late 2018 or 2019.

The 111(d) Rule's Devastating Impact on Rural Electric Cooperatives

26. The 111(d) Rule jeopardizes the ability of rural electric cooperatives to fulfill their mission under the congressionally crafted program to provide reliable and affordable electricity to their rural, predominantly lower-income residential member consumers.

27. By EPA's own admission, the coal-fired performance rates are so stringent that they cannot be achieved by existing power plants through available technological or operational measures at the plants themselves. That is true for many existing natural gas-fired units as well. The rural cooperatives agree with EPA's assessment – their existing operations cannot meet the new rates. As Anthony Campbell of Eastern Kentucky Power Cooperative conveyed, "[t]here is no viable technology or equipment modification to enable an existing EGU to meet the EPA's CO2 emission standards."[19] Similarly, as relayed by Kimball R. Rasmussen of Deseret Power, "[t]here exists no commercially viable technology

[19] Campbell Decl., ¶ 21.

which could be incorporated by Bonanza to reach EPA's limits."[20] EPA expects that many existing plants will be retired before the end of their natural life simply to comply with the 111(d) Rule. To replace lost generation, many G&Ts will be forced to close or curtail generation at existing units and to shift generation to lower or zero-emitting sources like natural gas, nuclear, or renewable energy.[21]

28. While the Rule's compliance period begins in 2022 and final standards must be achieved by 2030, as explained above in paragraph 13, electric utilities must begin taking steps well in advance of those deadlines – many immediately or imminently – if they are to comply by the specified deadlines. NRECA's G&T members will need to take actions that affect planning and resource allocation – like siting decisions, preparing permit applications, and negotiating pipeline contracts, power purchase agreements, construction contracts, and other commitments like long-planned capital investments and improvements – long before any state plans implementing the 111(d) Rule are submitted, well before EPA's proposed Federal Implementation Plan and model state trading rules

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[20] Rasmussen Decl., ¶ 3; *see also* Brummett Decl., ¶ 16; Lisa Johnson Decl., ¶ 15; Jura Decl., ¶ 8; Ledger Decl., ¶ 10; McInnes Decl., ¶¶ 9-10; McLennan Decl., ¶ 11; Rasmussen Decl., ¶¶ 6-7.

[21] *See* Brummett Decl., ¶ 26; 31-41; Campbell Decl., ¶ 21; Lisa Johnson Decl., ¶¶ 6, 12; Jura Decl., ¶¶ 8, 32; Ledger Decl., ¶ 10, 30; McInnes Decl., ¶ 13; McLennan Decl., ¶¶ 10, 19; Rasmussen Decl., ¶ 7.

are finalized, and almost certainly before this litigation is resolved.[22] Because cooperatives must make business decisions almost immediately to prepare to comply with the 111(d) Rule, the Rule will have imminent and irreparable economic consequences if it is not enjoined until this Court has had a full opportunity for review.

29. A stay of the 111(d) Rule is also critical for mine-mouth coal-fired power plants (that is, power plants that burn coal from an immediately adjacent coal mine) because those plants must make critical capital expenditure decisions for a mine as well as a power plant. As explained by Derrick Brummett on behalf of NRECA member San Miguel, capital investments required to open new areas of the San Miguel mine (which is the plant's only source for fuel) are typically planned years in advance and are justified by significant net savings from mining

[22] *See* Brummett Decl., ¶ 26; Campbell Decl., ¶ 23; Ledger Decl., ¶¶ 29, 34; Lisa Johnson Decl., ¶ 7; Jura Decl., ¶ 9; McInnes Decl., ¶¶ 14, 20-22; McLennan Decl., ¶ 14. Many substantial capital investments would otherwise be made and cooperatives must decide soon whether to go forward with those investments for assets that may soon be shuttered. *See* Lisa Johnson Decl., ¶ 29; Jura Decl., ¶ 20; Ledger Decl., ¶ 34; McInnes Decl., ¶¶ 7, 20-21; McLennan Decl., ¶¶ 15-18. Importantly, cooperatives cannot make business decisions in reliance on a possibility that future trading programs will be affordable or even adopted at all. *See* McInnes Decl., ¶ 18 (discussing the "little certainty that enough credits or allowances will be available for purchase. And even if they are available for purchase, they will likely be at unreasonably high prices"); Rasmussen Decl., ¶ 10 (stating that the tribal government for the Uintah/Ouray Reservation on which the Bonanza Generating Station is located opposes any cross-border or inter-jurisdictional emissions trading).

lower-cost fuel in new areas of the mine compared to continuing mining operations at areas of the mine where operational costs are higher due to the depth at which the coal is located or the distance of that area from the plant.[23] Unless the 111(d) Rule's compliance deadlines are extended, the 111(d) Rule forces San Miguel out of its normal decision-making process and into an un-deferrable choice that has two options which both risk irreparable harm: (1) to continue into the new mining area to save operational costs but expose itself to the risk that it will not have time to recover the additional debt incurred without dramatic rate increases or (2) forego the new mining area and expose its members to immediate higher operational costs and rates.[24] A stay and extension of compliance deadlines mitigates this dilemma by affording sufficient time for San Miguel to recover the additional debt associated with the new mine area and avoid higher operational costs in the meantime.

30. Whether G&Ts choose to construct new gas-fired and renewable resources,[25] or try to purchase generation capacity in what will likely be a crowded

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[23] Brummett Decl., ¶¶ 30-37.

[24] *Id.* ¶¶ 38-39.

[25] Many G&Ts will choose a mix of natural gas fired- and renewable replacement generation resources, or new natural gas fired-resources alone. *See, e.g.*, Campbell Decl., ¶ 21; Lisa Johnson Decl., ¶¶ 19, 24; Jura Decl., ¶¶ 24, 26; Ledger Decl., ¶¶ 27-28; McLennan Decl., ¶ 19. Notably, renewable resources alone are not well-

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and uncertain market, they will have to make enormous capital investments to comply with the 111(d) Rule.[26] For example, East Kentucky Power Cooperative will likely have to expend more than $500 million to retrofit or acquire new generation assets.[27] As explained above in paragraphs 14 and 16-18, G&Ts must obtain 100 percent (relatively high-cost) financing to pay for those investments.

31. To pay for that high-cost financing and additional capital costs, G&Ts will have to raise rates significantly and unduly burden their rural, low-income consumers.[28] In addition, they will still be carrying outstanding debt from prematurely retired assets, which will in turn negatively affect their credit ratings.[29] Their rates likely will be forced to increase even further to cover the costs of

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suited to serve as baseload generation. *See* Ledger Decl., ¶ 25; McLennan Decl., ¶ 19.

[26] *See, e.g.*, Campbell Decl., ¶ 21; Lisa Johnson Decl., ¶¶ 25, 27; Jura Decl., ¶ 25; Ledger Decl., ¶¶ 27-28; McInnes Decl., ¶¶ 18-19, 21; McLennan Decl., ¶¶ 22-23.

[27] Campbell Decl., ¶ 21.

[28] *See, e.g.*, Brummett Decl., ¶¶ 20, 23, 28; Campbell Decl. ¶¶ 24-25; Lisa Johnson Decl., ¶¶ 8-9, 25, 32; Jura Decl., ¶¶ 11-12, 29, 32; Ledger Decl., ¶ 9, 29; McLennan Decl., ¶ 8, 23; Rasmussen Decl., ¶ 9.

[29] *See* Brummett Decl., ¶¶ 20-40, 42; Campbell Decl., ¶ 21; Lisa Johnson Decl., ¶ 28; Jura Decl., ¶ 29; McInnes Decl., ¶ 7; McLennan Decl., ¶ 23.

generation while continuing to pay for the sunk costs and outstanding debt associated with prematurely-retired units.[30]

32. Higher rates may mean that cooperatives are no longer competitive with the rates of other electric utilities within the other electric utility segments.[31] Also G&Ts saddled with higher generation costs relative to other electric utilities will lose abilities to effectively compete in organized wholesale markets to sell excess power resulting in forcing additional cost increases to the electric cooperative consumer. Reliable electric service may also be jeopardized – reduced coal generation may impair a cooperative's ability to respond to unforeseen weather events from unexpected low or high temperatures.[32]

33. In the time that it would typically take for a court to review the legality of a rule like the 111(d) Rule, absent a stay, NRECA members will be forced to make irreversible commitments that will place their feet firmly on the path toward significantly higher rates, harming rural consumers and providing a disincentive for rural economic development. Cooperatives would be in jeopardy of failing to fulfill their mission under the federally-crafted rural cooperative

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[30] *See, e.g.*, Campbell Decl., ¶ 21; Johnson Decl., ¶ 26; Jura Decl., ¶ 27; Ledger Decl., ¶ 28; McLennan Decl., ¶¶ 8, 23; Rasmussen Decl., ¶ 9.

[31] *See* Johnson Decl., ¶ 32; Jura Decl., ¶ 32.

[32] *See* Campbell Decl., ¶ 26; Ledger Decl., ¶ 33.

structure to continue to provide rural and low-income consumers with reliable, affordable electricity.

Pursuant to 28 U.S.C. § 1746, I declare under the penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Executed: October 14, 2015

By: ______________________
Kirk Johnson

ATTACHMENT L

TO

MOTION OF UTILITY AND ALLIED PETITIONERS FOR STAY OF RULE

Declaration of Michael McInnes (Sept. 25, 2015)

Declaration of Micheal McInnes

I, Micheal McInnes, declare that the following statements made by me are true and accurate to the best of my knowledge, information, and belief:

1. I am the Chief Executive Officer of Tri-State Generation and Transmission Association, Inc. ("Tri-State"). From 2008 to 2014, before I assumed my current position, I served as Tri-State's Senior Vice President of Production and was responsible for the day-to-day oversight and operation of Tri-State's power generating facilities, coal mining operations, and land and water resources. From 2000 to 2008, I had primary responsibility for Tri-State's budget, environmental, risk management, safety, security, human resources, supply chain and procurement functions. Immediately prior to joining Tri-State in 2000, I was Executive Vice President and General Manager of Plains Electric Generation and Transmission Cooperative in Albuquerque, N.M.

2. Organized in 1952, Tri-State's mission is to provide reliable, cost-based wholesale electricity to its 44 not-for-profit member systems (electric cooperatives and public power districts). Its members serve 1.5 million predominantly rural consumers over 200,000 square miles of

territory in Colorado, Wyoming, Nebraska, and New Mexico. Tri-State owns several fossil fuel-fired electric generating units ("EGUs") in these states that are subject to EPA's Clean Power Plan ("Rule"). In 2014, Tri-State sold approximately 18.7 million megawatt-hours of electricity, at least 11.9 million megawatt-hours of which was generated by fossil fuel-fired sources covered by the Rule.

3. Tri-State's member systems serve a wide array of customers and demographics, from areas experiencing significant oil and gas development, to high production agricultural lands, to some of the most rural communities in America. In general, Tri-State's members serve low-density areas, which average less than 5 customers per mile of distribution line (compared to an average of over 35 customers per mile of distribution line for investor-owned and municipal utilities). Thirty-two percent of the power Tri-State generates or purchases is used to meet residential load, 55 percent meets commercial and industrial load, 8 percent meets irrigation load, and the remaining 5 percent meets miscellaneous load needs.

4. As a not-for-profit cooperative, Tri-State passes all of its costs along to its members. Tri-State's power is sold to some of the most

poverty-stricken counties in New Mexico and southern Colorado. Cognizant of this fact, Tri-State strives to keep its costs low and to deliver electricity at costs competitive with for-profit utilities by concentrating on efficiencies and cost instead of shareholder profits.

5. In a cooperative model, the member-owners of the cooperative bear all of Tri-State costs, including transmission and generation capital, operation and regulatory compliance expenses. Electric cooperatives were created when investor-owned utilities ("IOUs") would not supply power to rural customers because of high development costs and low profit margins. In 1935, President Franklin Roosevelt established the Rural Electrification Administration ("REA"), now the Rural Utilities Service, as part of the New Deal. The REA managed low-interest and long-term loan programs to help establish electric service to rural customers via rural electric cooperatives.

6. The ownership structure and fundamental purpose of electric cooperatives differentiate them from IOUs and municipal utilities. Electric cooperatives are not-for-profit, consumer-owned businesses. Their primary regulatory bodies consist of democratically elected boards of directors. Electric cooperatives work to ensure that

families and small businesses nationwide are able to effectively compete in the marketplace and to minimize the effects of market volatility and regulatory change that affect the electric utility industry. Electric cooperatives make power generation and transmission affordable to their members because of the economies of scale achieved by joining together. Electric cooperatives sell power to their members at cost. Electric generation and transmission ("G&T") cooperatives like Tri-State are formed and owned by electric distribution cooperatives. G&T cooperatives purchase wholesale power and generate electric power for their members. Any revenue gained in excess of expenses results in margins (commonly referred to as "patronage capital") that belong to the member systems and are returned to them, used to pay debt, cover operating costs, or fund future activities. Because Tri-State has a smaller generation fleet than many utilities, it will have a more difficult time meeting the requirements of the Rule because it has less flexibility within its fleet to generate power from different sources.

7. As a not-for-profit cooperative, Tri-State passes all of its costs along to its members, including the cost of financing for capital projects. Tri-State's cost of capital and ability to access capital may be

adversely affected by the Rule. For 2015 through 2019, we estimate that we may invest approximately $1.9 billion in new facilities and upgrades to our existing facilities which will require us to take on significant additional long-term debt. Many creditors may choose not to invest in Tri-State or may require higher interest rates if they have concerns over how the Rule will affect Tri-State. Further, Tri-State's interest costs are closely related to its credit ratings from Moody's, Standard and Poor's, and Fitch. A credit downgrade from any or all of the three rating agencies because of the negative financial implications of the Rule would result in higher borrowing costs and constrained access to the capital markets.

8. Over time, Tri-State strives to match the average life of its debt to the average life of its assets. The uncertainty surrounding the Rule may force Tri-State to make sub-optimal financing decisions. For instance, it may be in Tri-State's best interest to issue long-term debt, however it could be forced to issue short-term debt if the market is uncertain whether the lives of Tri-State's assets will be shortened.

9. The Rule establishes a uniform emission rate for coal-fired EGUs of 1,305 lb CO_2/MWh and bases all of the requirements for coal-

fired EGUs in the Rule on that rate. EGUs must generally begin making progress toward meeting this 1,305 lb CO_2/MWh rate in 2022 and must achieve it by 2031. Alternatively, each state may adopt an approach wherein all affected EGUs (both coal-fired and natural gas-fired) in the state must collectively meet an overall goal (which can be either mass- or rate-based) on that same timeframe. In the states where Tri-State owns generation assets, the state goals are even lower than the 1,305 lb CO_2/MWh standard: Arizona's final emission rate goal is 1,031 lb CO_2/MWh, Colorado's is 1,174 lb CO_2/MWh, Nebraska's is 1,296 lb CO_2/MWh, New Mexico's is 1,146 lb CO_2/MWh, and Wyoming's is 1,299 lb CO_2/MWh.

10. Existing coal-fired EGUs in the United States generally operate with emission rates in excess of 2,000 lb CO_2/MWh, and Tri-State's coal-fired EGUs are no exception. By themselves, Tri-State's coal-fired EGUs are not capable of meeting the applicable emission rate, and there is no known, commercially available technology that can be applied to the EGUs that will enable them to meet that rate. This means that Tri-State will need to (a) shut down those EGUs, (b) curtail those EGUs, and/or (c) generate or buy credits or allowances under a

trading program(s).In each of these possible scenarios, Tri-State will need to take significant and costly measures to comply with the Rule. Although the Rule references an "optional" market-based trading program, if all states do not opt in, there will be limited trading opportunities and limited credits or allowances available on the market. Moreover, there is no guarantee that the states in which Tri-State has generation will opt into the market-based programs. Even if they do, the cost of credits or allowances may be unreasonably priced.

11. The majority of the emission reductions that result from the Rule come from displacing higher emitting generation sources (such as coal-fired EGUs) with existing lower emitting sources (such as natural gas-fired EGUs and renewable generation resources).

12. Under the Rule, it will be impossible for all coal-fired EGUs to continue to operate at their historical capacity factors. Even in a market-based system, there will not be enough allowances or credits available. A significant number of coal-fired EGUs will be forced to close down and cease operations to free up allowances, and those that do remain in operation will likely have to curtail their operations significantly. EPA admits this is the case. EPA, Regulatory Impact

Analysis for the Clean Power Plan Final Rule, at 6-21 (Aug. 2015). Having to close down or severely curtail the operations of Tri-State's coal-fired EGUs will create significant stranded costs and may risk its ability to affordably invest in the additional needed capacity (renewables and natural gas-fired EGUs) that will be necessary for it to meet its contractual obligations to supply electricity.

13. The fact that a large percentage of coal-fired EGUs will need to close down as a result of the Rule is having an immediate harmful impact on Tri-State. Tri-State has limited options for shifting operations to a lower emissions unit. To ensure it can meet its contractual obligations to its members, Tri-State will very likely have to invest in new generation resources, which come at a significant capital expense, exclusively for the purpose of complying with the Rule, or it will have to purchase power from others. Additional costs will be incurred to develop and otherwise secure replacement generation. The EPA rule contains provisions that suggest states also regulate new gas units under a mass based system to limit the amount of gas units that can be built. Decisions about replacement generation need to be made many years in advance to allow adequate time for planning, permitting,

and construction. If the Rule is not stayed, Tri-State will need to begin making these decisions now, and once these decisions are made, they cannot be reversed without harm to Tri-State.

14. Transmission development and construction is also a significant issue for Tri-State. The process to plan, route, permit, and obtain land rights for new transmission lines can take many years. Until state plans are finalized and approved by EPA, Tri-State will not know for sure whether it needs to develop new transmission for any replacement generation or renewable generation needed for compliance purposes that it will need to construct. State plans can be approved by EPA as late as September 6, 2019, which would leave Tri-State with less than three years to make decisions and complete projects before the first interim period begins on January 1, 2022. This is not enough time to complete necessary projects to comply with the first interim compliance period. Tri-State will need to make significant financial commitments prior to 2019 in order to ensure that compliance obligations can be made. If Tri-State proceeds with projects that become unnecessary if the CPP is vacated because it is found wholly or partly unlawful, then it would have inappropriately allocated precious

capital funds. If Tri-State does not proceed with these projects, however, it runs the risk of either being unable to comply with the interim period goals or being unable to meet its obligations to its members.

15. Siting and permitting transmission is a complex and potentially controversial process that requires a large number of permits, consultations, and approvals from multiple federal, state, and local government bodies, tribal authorities and private parties before construction even begins. In some cases, approvals cannot be secured at all, despite years of effort and investment. The timeline for a transmission project depends on completion of planning studies and technical analysis, real estate availability (negotiating rights-of-way or exercising eminent domain authority), procurement of long lead-time equipment, environmental permitting requirements, public involvement, regulatory approval, and opportunities for equipment outages to interconnect the new facilities. A relatively simple project that will not traverse an environmentally sensitive area, require the exercise of eminent domain, or involve significant public opposition will take up to three years prior to construction. More complicated projects

that will traverse federal lands, environmentally sensitive areas, or will generate public opposition may require 10 years or more to complete. Examples of recent transmission projects by Tri-State demonstrate this: (1) the United Power 115 kV Transmission Improvement Project required 10 years to obtain pre-construction approval for only 15 miles of transmission line; (2) the Nucla-Sunshine 115 kV project endured a 13-year pre-construction process, and it took 15 years to complete the line from the time the permitting process initially commenced; and (3) the Colorado-New Mexico Intertie Project began in 1997 and did not end until 2006.

16. In some cases, utilities have been forced to abandon projects, including Tri-State's abandonment of a transmission line called the San Luis Valley-Calumet-Comanche project, which was a 230/345 kV project that received a Certificate of Public Convenience and Necessity from the Colorado Public Utilities Commission approving the project. The project ultimately had to be abandoned due to opposition from a private landowner.

17. Once it becomes apparent to Tri-State that it will need to shut down or decrease operations in one of its EGUs as a result of the

Rule, it will then be required to partially or wholly impair that asset. The impairment of the asset would happen upon knowing that the EGU would be forced to close or have decreased operations in the future and cannot wait until the actual closure or until operations are actually decreased. Impairment of an asset cannot be reversed. This means that if Tri-State begins to impair an asset and the Rule were later found to be unlawful, it would not be able to go back and reverse the impairment of the portion of the asset that had already been written off.

18. Even if Tri-State's coal-fired EGUs would not have to close down as a result of the Rule, those EGUs will need to severely curtail their operations or Tri-State will need to obtain allowances or credits to cover their emissions. Tri-State believes that assuming there will be surplus allowances or credits available for purchase at a reasonable price is a questionable business practice. The gap between actual emission rates for coal-fired EGUs and the requirement contained in the Rule is so large that there is little certainty that enough credits or allowances will be available for purchase. And even if they are available for purchase, they will likely be at unreasonably high prices. Because of the time that is needed to build new generation and

transmission (as discussed above), Tri-State will need to decide now whether to begin planning and construction or gamble that credits or allowances will be available at an affordable price. Neither of these is an attractive option, and both lead to irreparable harm if the decision (which has to be made now without full information) turns out to be the wrong one.

19. Tri-State's coal-fired EGUs provide baseload power. Severely curtailing their operation can have serious consequences, including higher CO_2 emissions rates and increased production costs. In addition, because Tri-State's coal-fired EGUs were designed for baseload and not for cycling (backup) service, the curtailed use of these units as backup generation will wear the EGUs out at a faster pace, further increasing production cost and decreasing reliability. If these units are going to be used for cycling service, it would be prudent for Tri-State to plan and make changes to these EGUs to make them more suitable for that purpose. These can be long-term projects that need to be evaluated, planned, designed, procured, and constructed during a scheduled outage over many years. This process should begin now if these units are to become cycling units. If Tri-State starts this process

now, however, and spends money on such an effort only to have the Rule later vacated, this will cause irreparable harm to Tri-State. On the other hand, if Tri-State doesn't start the process now, and the Rule remains in place, this will also cause irreparable harm to Tri-State. Without certainty over whether the Rule will survive the legal challenges, there are no good options for Tri-State that avoid harm.

20. The Rule is also affecting Tri-State's ability to make certain capital expenditures or enter into contractual commitments for things such as fuel or raw materials. In general, capital projects and contractual commitments are only entered into if the payback can be realized during the remaining useful life of the EGU. Due to concerns from the Rule about whether coal-fired EGUs may need to shut down before the end of their useful life or severely decrease operations from historical levels, Tri-State is having to be cautious about making certain capital expenditures or entering into contractual commitments. If Tri-State proceeds with projects with a long payback period, there is a risk that the payback will not be realized before the EGU is retired as a result of the Rule or that the payback period changes as a result of the reduction in operations. If Tri-State does not proceed with projects with

a long-term payback period, there is a risk that it is not maintaining its equipment in accordance with best practices. Applying a fiscal prudence to this situation, Tri-State is currently focused on projects with relatively short payback periods. Although this tactic provides it with certainty that it is not wasting money, it is far from the best practice for maintaining and operating a valuable asset. Similarly, decisions such as entering into long-term coal contracts are not prudent if the EGU for which the coal is being purchased is going to shut down or decrease operations. As a result, Tri-State is unable to take advantage right now of the ability to enter into long-term contracts that might be in Tri-State's best economic interest.

21. Decisions also need to be made right now regarding the installation of expensive emission controls on one of Tri-State's coal-fired EGUs—Unit 1 of Tri-State's Craig Station in Colorado. Tri-State is under compliance obligations to install selective catalytic reduction at the Unit to control emissions of nitrogen oxides by 2021 as part of the Regional Haze Program. Installing these controls costs hundreds of millions of dollars and is a five-year process that must begin in 2016 (before the legality of the Rule will be determined and before state plans

will be submitted and approved by EPA). If Tri-State is going to have to shut down Unit 1 or severely curtail its operation as a result of the Rule, then investment in these controls would be a waste of money. Without certainty as to whether the Rule will go forward, and if it does, whether Unit 1 will be forced to shut down, Tri-State is in a position where it cannot make an informed decision, and if it makes the wrong decision, it will be irreparably harmed. Tri-State's situation is identical at the Laramie River Station in Wheatland, Wyoming. Tri-State is a part owner of that three-unit facility and faces an investment of nearly $100 million to meet Regional Haze requirements in Wyoming.

22. Tri-State has recent experience with making significant investments to comply with an environmental regulation and having that regulation later be found unlawful. Tri-State recently installed emission controls at six coal-fired EGUs to comply with EPA's Mercury and Air Toxics Standards ("MATS"). After installation of these controls, the Supreme Court found that EPA did not properly consider costs as it developed MATS and remanded the case back to the D.C. Circuit. This was a hollow victory for Tri-State, which had already spent millions of

dollars to comply. A stay of the Rule is needed to avoid this type of result.

23. The Rule also contains provisions for a new Clean Energy Incentive Program that will provide credits for early action for any wind and solar energy projects that commence construction after the state in which the project is located submits its final state plan to EPA, or after September 6, 2018, if the state is subject to a federal plan. Credits can be granted for any electricity generated by those projects in 2020 and 2021. If Tri-State wants to take advantage of this aspect of the Rule, it needs to start planning for construction now because it takes time to get the permits and financing for such construction. But if Tri-State enters into commitments for these projects and the Rule is invalidated, then this will not have been a good use of Tri-State's funds. On the other hand, Tri-State would normally consider trying to take advantage of this program if the Rule does go forward because Tri-State is an electric cooperative with low-income members and projects in those areas may qualify for additional credits – although it is impossible to know that at this time as EPA has not yet defined what "low income" means for the

purpose of the Rule. In addition, there are a limited amount of credits available, so to take advantage, Tri-State needs to act quickly.

24. For all of these reasons, Tri-State will experience irreparable and irreversible harm from the Rule well before the compliance obligations of the Rule go into effect.

I make this Declaration under penalty of perjury pursuant to 28 U.S.C. § 1746, and I state that the facts set forth herein are true.

Micheal S. McInnes

Micheal McInnes

Dated: 25 SEP, 2015

ATTACHMENT M

TO

MOTION OF UTILITY AND ALLIED PETITIONERS FOR STAY OF RULE

Declaration of Jim P. Heilbron (Oct. 8, 2015)

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

Utility Air Regulatory Group,	)	
	)	
Petitioner,	)	
	)	
v.	)	Case No. __________
	)	
U.S. Environmental Protection Agency,	)	
	)	
Respondent.	)	

DECLARATION OF JIM P. HEILBRON

I, Jim P. Heilbron, declare:

1. I am the Senior Production Officer ("SPO") of Alabama Power Company ("Alabama Power" or the "Company"). As SPO, I oversee Alabama Power's electricity generation operations and, as part of our generation planning efforts, I rely on information and input from the Company's transmission planning group. I have been in this role since March 2013. I have worked within the Southern Company system for seventeen years. I served as the SPO of Southern Power Company from July 2010 to February 2013. Before that, I was Plant Manager at Georgia Power Company's Plant Wansley starting in 2006. I held various other roles within the system prior to 2006. I hold a Bachelor's Degree in Civil/Environmental Engineering and a Master's Degree in Environmental Engineering from Auburn University. I also hold a Master's in Business Administration from Emory University.

2. In this declaration, I identify numerous impacts to Alabama Power, its employees, its customers, and its local communities if we are required to undertake the steps the Environmental Protection Agency ("EPA") itself has forecasted in its Regulatory Impact Analysis of the Clean

Power Plan. Based on EPA's Integrated Planning Model ("IPM") analysis, the impacts to Alabama Power include:

- The premature shuttering of over 2,600 megawatts ("MW") of fossil fuel-fired units, constituting approximately 21% of Alabama Power's generating capacity, with more than 1,800 MW with a current value of approximately $1.2 billion identified for retirement in 2016 alone;
- Higher production costs and an insufficient reserve margin, resulting in increased customer costs of approximately $590 million in 2016-2017;
- Costs in excess of $350 million for needed transmission projects, with approximately $72 million in costs in 2016-2017;
- Costs in 2016-2017 of $344 million to compensate for impacts to the fuels program;
- Loss of approximately $3 million in annual property taxes used by local governments beginning in 2016; and
- Loss of over 350 full-time jobs in 2016-2017 alone.

3. Based on EPA's results, and because it takes many years to plan and implement changes to our generating and transmission resources, Alabama Power would have to begin activities immediately in 2016 and 2017 regardless of the specifics of any state or federal plan ultimately adopted to implement the Clean Power Plan. This is because, according to EPA, the retirements identified by the IPM are already the current "best assessment of likely impacts of the [Clean Power Plan] under a range of approaches that states may adopt." EPA, Regulatory Impact Analysis 3-11 (Aug. 2015) ("RIA"), *available at* http://www3.epa.gov/airquality/cpp/cpp-final-rule-ria.pdf. Moreover, as explained below, many of these impacts could not be reversed once the changes to the generating and transmission resources have begun.

4. Alabama Power is a subsidiary of Southern Company, serving the southern two-thirds of Alabama. Alabama Power delivers 1.4 million customers safe, reliable, and affordable electricity service generated from a full portfolio of energy resources, comprising 24 fossil, nuclear, and hydro-electric generating plants. As the SPO, I and my staff are charged with ensuring the reliability and cost-effectiveness of Alabama Power's generation.

5. Alabama Power is a vertically integrated, regulated utility that not only produces electricity but also ensures the safe, reliable, and affordable transmission and distribution of that electricity to our customers.

6. Alabama Power has and applies tools to assess and project the status of our power plants and transmission network to ensure reliability and availability as part of an annual resource planning process.

7. Alabama Power has a horizon of forty years for many of its planning decisions. Most of the activities we undertake require years, and sometimes decades, to plan and execute. Depending on the type of generation (combustion turbine, natural gas combined cycle ("NGCC"), nuclear, etc.), new generation plants require from four to seventeen years to obtain regulatory approvals, plan, site, design, permit, construct, and commission. For example, a new NGCC takes approximately seven to eight years to obtain regulatory approvals, engineer, procure, construct, and place in service. Accordingly, if a new NGCC were needed to be placed into service in 2022, activities to meet that projected in-service date would have to begin immediately. Likewise, identifying, developing, planning, and then building transmission projects can require years to implement, particularly when property rights for new power line corridors must be obtained. In sum, the nature of the utility planning process requires us to take

actions well in advance of a forecasted event or need in order to ensure that we maintain our ability to provide the most cost-effective and reliable electric service possible to our customers.

8. I provide this declaration in support of the Utility Industry's motion to stay the EPA's "Carbon Pollution Emission Guidelines for Existing Sources: Electric Generating Units" ("Final Rule" or "Clean Power Plan"). EPA, *Carbon Pollution Emission Guidelines for Existing Sources: Electric Generating Units* (signed Aug. 3, 2015), *available at* http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf.

9. I hereby rely upon all statements and analyses provided by Kim Greene, Southern Company's Chief Operating Officer, on behalf of the Southern Company system.

10. This declaration is based on my personal knowledge of facts and analysis conducted by Alabama Power and Southern Company staff and me.

SUMMARY OF EPA'S CLEAN POWER PLAN

11. On August 3, 2015, EPA promulgated its Final Rule under Section 111(d) of the Clean Air Act. The Final Rule establishes interim and final national "performance rates" for existing fossil fuel-fired steam boilers and for NGCCs. The interim performance rates, which apply from 2022 through 2029, are established as the emission of 1,534 lbs CO_2/MWh and 832 lbs CO_2/MWh for fossil fuel-fired steam boilers and NGCCs, respectively. Beginning in 2030 and thereafter, the fossil fuel-fired steam boiler and NGCC performance rates drop to 1,305 lbs CO_2/MWh and 771 lbs CO_2/MWh. EPA used these interim and final national performance rates to establish state-specific, rate-based and mass-based goals, which were calculated by applying the performance rates to each state's 2012 generation mix. EPA's goals for fossil fuel-fired generating units in Alabama are shown in the table below.

EPA's Goals for Fossil Fuel-Fired Units in Alabama

	Rate-Based Goal (lbs. CO_2/MWh)	**Mass-Based Goal (short tons)**
Interim (2022-2029)	1,157	62,210,228
Final (2030)	1,018	56,880,474

EPA'S REGULATORY IMPACT ANALYSIS

12. In performing its Regulatory Impact Analysis of the Final Rule, EPA relied on the IPM to define "a least cost way to achieve the state goals . . . ." RIA at ES-4. Through this modeling, EPA developed a "compliance solution" for each state—i.e., the set of plant retirements, shifts in utilization of remaining generation, and new generation that would demonstrate compliance with the Clean Power Plan's required reductions.

CONSEQUENCES IDENTIFIED IN EPA'S REGULATORY IMPACT ANALYSIS

13. Under EPA's compliance solution, Alabama Power must retire over 2,600 MW of fossil fuel-fired units by 2030, as shown in the table below, which constitutes approximately 21% of Alabama Power's generating capacity. Of that 2,600 MW, EPA predicts that *more than 1,800 MW will retire in 2016 alone*.

Alabama Power Retirements under EPA's Compliance Solution

Unit	Year	Net Summer Peak MW Capacity (APC Ownership Portion Shown in Parentheses)
Barry 1, 2, & 4	2016	637
Greene County 1	2016	262 (157)
Gorgas 8-10	2016	1,043
Greene County 2	2020	255 (153)
Gadsden 1-2	2025	130
Gaston 1-4	2025-2030	1030 (515)

As described in Kim Greene's declaration, we have determined some of the immediate and irreparable consequences of these premature retirements for Alabama Power. Although I focus on those harms that would occur as a result of retirements in 2016, even if the retirements identified by EPA in its compliance solution did not occur until 2022 (the first year of the interim compliance periods), Alabama Power would suffer irreparable harm in the near-term given the decisions and actions that would be necessary now to prepare for those retirements.

Impacts to Reserve Margins

14. The retirements shown in EPA's compliance solution reflect Alabama Power retirements of over 1,800 MW in 2016, and overall Southern Company system retirements of over 8,000 MW in 2016. While Alabama Power has its own obligation to meet customer needs, the Company's generating and transmission resources are physically connected to and integrated with the rest of the Southern Company system, and balancing combined customer demand and generation is done at the system level.

15. The premature retirement of over 8,000 MW in 2016 would negatively impact the reserve margin of the Southern Company system. A reserve margin is a measure of the amount of resources available in excess of forecasted demand. Southern Company's long-term reserve margin is established at 15% and is necessary to maintain reliability on the system, taking into account risks due to non-normal weather, unit outages, and inherent inaccuracies in demand forecasts. EPA's compliance solution would dangerously reduce Southern Company's long-term reserve margin below the established 15% to 4.8% in 2016 and 2.9% in 2017. These drastically reduced reserve margins would have significant reliability and cost implications. Furthermore, the Company's response to these reliability and cost implications cannot be unwound, because once an electric generating unit is retired, it is not feasible to return the same unit to service.

16. The Southern Company system's reserve margin depends not only on physical generating assets but also on customer participation in what are referred to as "demand-side options." These demand-side options are agreements with some customers to interrupt some or all of their service when needed (for example, a factory with three production lines may agree that it will shut down one or more production lines for a certain time period when asked to do so).

17. If such demand-side options were no longer available, the Southern Company system's reserve margin would be negative in 2016 and 2017 under EPA's compliance solution. This would mean there are not enough generation resources to match even forecasted demand under normal weather conditions, much less under extreme weather conditions. An example of demand-side options becoming unavailable is if the factory participant (described above) chooses to exit the program because its power was interrupted frequently rather than rarely.

18. The premature retirement of over 8,000 MW of generation in 2016 would also drive the Southern Company system's reliability far outside of common industry practice. One industry

measure of sufficient generating resources is to avoid having more than one customer electricity service interruption over a ten-year period. The Southern Company system currently has sufficient generation to be below this measure. However, the retirement of over 8,000 MW in 2016 would drive that measure for the Southern Company system to twenty-four events every ten years, or twenty-four times higher than common industry practice.

19. The retirements and generation shifts shown in EPA's compliance solution would also lead to an increase in generation production costs, because more expensive generation will need to operate to partially replace the less expensive generation that is retired or utilized less. In addition, there would be an impact on customers associated with the cost of unserved energy. Unserved energy is customer demand for electricity that cannot be met due to generation deficiencies. This unserved demand is manifested as controlled, temporary shut-off of electric service in a rotating manner to groups of firm load customers in order to maintain compliance with North American Electric Reliability Corporation ("NERC") standards. Customers with unmet demand suffer economic costs. The economic impact to Alabama Power customers from such higher production costs and unserved energy would be approximately $590 million during the 2016-2017 time period.

20. If these retirements occurred in 2022, the reserve margin impacts would be deferred until 2022. However, even if the retirements occurred in 2022, the Southern Company system would still have to begin taking action immediately in 2016-2017 to prepare for the retirements. For example, if the Southern Company system sought to replace the retired generation through the construction of NGCCs in order to reach the target planning reserve margin in 2022, the planning process would have to begin immediately, and there would be $158 million of expenditures in 2016-2017. Alabama Power Company's share of spending would be $7 million.

Impacts to Transmission

21. A preliminary screening analysis was performed by Alabama Power's transmission planning group to assess the impacts to the transmission system due to the unit retirements identified in EPA's compliance solution. I have received the results from Alabama Power's transmission planning group as detailed below. This is the type of information that is utilized as an input in the Company's planning process. The preliminary screening analysis used to determine the transmission system impacts, as well as associated transmission projects and estimated costs, was limited to power flow analyses developed with transmission planning models for the years 2016 and 2022 to monitor thermal and voltage constraints in our transmission system. Additional transmission analyses, such as dynamic analysis and assessments of off-peak system conditions, would need to be performed to identify a comprehensive set of transmission projects needed to maintain reliability. It would take many months to perform these additional transmission analyses, and thus they are not included in this declaration. It is anticipated that such analyses would likely identify additional, significant transmission impacts due to the unit retirements identified in EPA's compliance solution.

22. As a result of the unit retirements identified in EPA's compliance solution, a significant amount of replacement generating capacity will be needed to maintain resources adequate to reliably serve the demand for electricity. For purposes of our preliminary screening analysis, we assumed this replacement generating capacity would have to be procured from third-party resources because neither Alabama Power nor the Southern Company system would be able to build sufficient generation to replace the missing capacity by the 2016 closure dates identified in EPA's compliance solution. Under these resource assumptions, our analysis showed that in order to accommodate the unit retirements identified in EPA's compliance solution, numerous transmission projects must be undertaken in Alabama Power's service territory to maintain

compliance with NERC Reliability Standards. Specifically, as identified in the table below, at least sixteen additional transmission projects, including five new line and substation projects, at a cost in excess of $358 million, will be necessary in Alabama, $72 million of which would be expended in 2016-2017. These are conservative estimates for numerous reasons, including that they do not account for unserved energy from transmission constraints. Furthermore, and most critically, due to lead times required to complete these transmission projects, the transmission projects cannot be placed in service by the unit retirement dates identified in EPA's compliance solution. The new line and substation projects will require from five to seven years to complete. Projects at existing lines and substations will take approximately two to five years to complete. As a result, there will be increased risk to system reliability until these projects can be completed. Once new construction projects have begun, because they involve acquisition of long-term property rights, they cannot be easily unwound.

Transmission Projects Necessary in Alabama

Project Type	Number of Projects
New Line and Substation Projects	5
Existing Line and Substation Projects	11
Total	16

23. Even if the retirements identified by EPA for 2016 did not occur until 2022, when compliance targets set by the Clean Power Plan become effective, many of the actions identified above would not only still be necessary but would also still need to begin in 2016-2017 in order to minimize the reliability impacts of delivering electric service. Specifically, to accommodate those retirements, Alabama Power would still have to begin the transmission projects that require

five years or longer to complete, and the expenditure to support those projects would be in excess of $26 million in 2016-2017.

Impacts from Fuel Contracts and Inventories

24. Under EPA's compliance solution, across the Southern Company system as a whole, the operating companies will incur costs of approximately $950 million in the 2016-2017 timeframe due to the impact on our fuel contracts and fuel inventories. As referenced by Kim Greene, these include: (1) the incremental cost to reduce coal contract volumes, assuming diverting remaining coal shipments to other coal units whenever possible; (2) liquidated damages associated with transportation contract cancellations; (3) costs associated with other fuel-related impacts, such as incremental costs to reduce other materials' contract volumes, including limestone, gypsum, fuel oil agreements, and railcar leases; (4) costs to cancel firm transportation agreements for natural gas to retired units, assuming no remarketing capability; and (5) the increase in system production cost, which results from forcing coal units to operate in order to consume the retiring units' coal inventories (planned burn). Specifically, all of the costs within the system associated with reducing coal contract volume are directly associated with retirements identified at Alabama Power, totaling $325 million alone. In total in 2016-2017, Alabama Power will bear $344 million of costs associated with fuel contracts and inventories as shown below, and once contracts are cancelled, they cannot easily be reinstated. Even if some of these costs could be mitigated under force majeure, substantial impacts would clearly remain.

Costs to Alabama Power from Fuel Contracts and Inventories

Fuel Costs	Estimated Cost in 2016-2017 ($2015)
Coal Commodity Agreements	$325M
Additional Fuel Related Impacts	$2M
Gas Firm Transportation Cancellations	$12M
Coal Planned Burn	$5M
Total	**$344M**

Impacts to Local Economies

25. The retirement of the units defined in EPA's compliance solution would have immediate and irreparable impacts on local economies. In Alabama alone, local communities served by Alabama Power will lose approximately $3 million in annual property taxes beginning in 2016. These tax dollars are used by local governments to help fund basic services from police and fire protection to sanitation and education.

26. In addition to the dramatic reduction in tax base, the 2016 retirements will result in over 350 direct job losses, with more losses occurring as additional units are retired.

Remaining Useful Life

27. The premature retirement of Alabama Power's units identified in EPA's compliance solution will result in closure of units that otherwise would have been economic to continue operating for many years. Alabama Power has recently invested substantial capital resources in these units, primarily for compliance with other EPA regulations. The net book value of units identified as retiring in 2016 under EPA's compliance solution is over $800 million as of July 2015. In addition, Alabama Power has already committed nearly $400 million in investments to come online at those units in the next year.

Conclusion

28. Unless the Final Rule is stayed, EPA's compliance solution shows immediate and irreparable impacts on Alabama Power, its employees, its customers, and the local communities it serves. These impacts are caused by the retirement of significant generating capacity that EPA's model shows occurring in 2016, even though this capacity would otherwise serve Alabama's electricity needs for many years. The retirements identified in EPA's compliance solution would negatively affect our customers and the communities that we serve by increasing their cost for electricity, risking reliability, dramatically reducing the tax base, and causing substantial job losses.

29. Direct impacts to Alabama Power in excess of $415 million in 2016-2017 result from the need to undertake new transmission projects (which could not be completed in 2016) and from the impacts to fuel contracts and inventories.

30. Even if the retirements identified in EPA's compliance solution for 2016 occur in 2022, Alabama Power would be required to take action and incur approximately $33 million in costs in 2016-2017 to ensure that it can continue to provide safe, reliable, and affordable electricity service.

Respectfully submitted,

Jim P. Heilbron
Alabama Power, Senior Production Officer

October 8, 2015

ATTACHMENT N

TO

MOTION OF UTILITY AND ALLIED PETITIONERS FOR STAY OF RULE

Declaration of Lisa D. Johnson (Oct. 12, 2015)

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

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION, *et al.*

Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,

Respondent.

No. ______________

DECLARATION OF LISA D. JOHNSON OF SEMINOLE ELECTRIC COOPERATIVE, INC. IN SUPPORT OF MOTION TO STAY

I, Lisa D. Johnson, declare:

1. I am the CEO & General Manager of Seminole Electric Cooperative, Inc. ("Seminole"). In that capacity, I supervise more than 500 employees at three principal locations in Florida. I am directly responsible to Seminole's Board of Trustees for overall Seminole operations.

2. I have worked for Seminole for two years, starting in July of 2013. Before joining Seminole, I was senior Vice President and Chief Operating Officer at Old Dominion Electric Cooperative in Glen Allen, Virginia. I hold a Bachelor of Science Degree in Mechanical Engineering and Materials Science from Duke University, and I have worked in the electric utility sector for over twenty years. I serve as a Director on the Florida Reliability Coordinating Council, as the

Secretary/Treasurer of the Florida Electric Power Coordinating Group, as a Trustee on the Board of Averett University, as a Director and as a member of the Executive Committee on the Board of the Florida Electric Cooperatives Association, as a director on the Board of the Electric Power Research Institute, and as Second Vice-President of the National G&T Managers Association. I was named one of Virginia's most "Influential Women" in 2012.

3. Seminole is one of the largest not-for-profit rural generation and transmission ("G&T") cooperatives in the country. Seminole has been in operation since 1948 and became fully operational as a G&T cooperative in 1976. Seminole and its nine Member-distribution cooperatives (collectively, "Seminole") serve approximately 1.4 million people and businesses in rural areas of Florida across 42 counties.

4. On August 3, 2015, the United States Environmental Protection Agency ("EPA") signed the final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units ("111(d) Rule" or the "Rule").

5. The 111(d) Rule requires a drastic reduction in carbon dioxide ("CO_2") emissions from fossil fuel-fired generation, with a 32-percent reduction from 2005 levels required by 2030. The 111(d) Rule achieves those reductions through uniform CO_2 emission performance rates EPA has imposed on two

subcategories of existing power plants (coal- and natural gas-fired units), and statewide rate- or mass-based emissions goals that are formulated from the subcategory performance rates. States are required to formulate state plans for compliance and submit those plans to EPA for approval.

6. Although states must plan for compliance, affected units like those owned and operated by Seminole are responsible for compliance with the interim and final goals established in the Rule. Seminole cannot meet the new performance rates through any technological or operational changes at its existing units without curtailing generation or shuttering the plants, shifting generation to lower-emitting sources, and/or purchasing credits or allowances under a potential future trading program.

7. The 111(d) Rule could force Seminole to commit to curtailing coal and/or gas-fired generation or even shuttering all of its owned baseload and intermediate load electricity generating facilities, including both coal-fired units at Seminole Generating Station ("SGS") and the natural gas-fired combined-cycle unit at Midulla Generating Station ("MGS") by 2022 to comply with the Rule. Seminole will need to make planning and resource allocation decisions long before any final state plans implementing the 111(d) Rule are submitted to EPA for approval, before EPA's proposed Federal Plan and model state trading rules are finalized, and before this litigation is resolved. Because Seminole must make these

business decisions almost immediately to prepare to comply with the 111(d) Rule, Seminole and the communities it serves will incur imminent and irreparable consequences if the Rule is not enjoined until this Court has had a full opportunity for review.

Introduction to Seminole and its Generating Units

8. Like most electric cooperatives, Seminole serves rural areas that would not be profitable or feasible for other utilities to serve, and that such utilities historically declined to serve. As explained more fully in the Declaration of Kirk Johnson, filed on behalf of the National Rural Electric Cooperative Association, the principal purpose of rural electric cooperatives like Seminole is to provide affordable electricity to underserved rural and largely lower-income populations. To that end, Seminole provides essential electric service in primarily rural and low-income areas of Florida stretching from west of Tallahassee to south of Lake Okeechobee. Approximately one-third of Seminole's residential customers have household incomes below the poverty level. Seminole serves an average of less than 10 customers per mile of electric line, whereas nationally, investor-owned utilities average 34 customers per mile and publicly-owned utilities average 48 customers per mile. Some of Seminole's Member cooperatives ("Members") serve as few as 4.6 customers per mile of electric line.

9. The rural nature of Seminole's business means that fewer customers exist to share the costs of Seminole's energy infrastructure. Because Seminole is a not-for-profit cooperative, its costs are reflected directly in its rates for electricity.

10. Seminole's primary generation resources include the coal-fired SGS plant and the natural gas combined cycle ("NGCC") unit at MGS. Most of Seminole's generation occurs at SGS in Putnam County in northern Florida. SGS was constructed in the era of the "Powerplant and Industrial Fuel Use Act." The Act, which restricted new power plants from using oil or natural gas and encouraged the use of coal, was enacted in 1978, and was not repealed until 1987. SGS came online in 1984 and consists of two, 650-megawatt ("MW") coal-fired generating units. SGS has operated at an average capacity factor of 80 percent throughout the last 18 years. In other words, SGS is very heavily utilized. In fact, in 2014, SGS generated approximately 58 percent of the total energy Seminole provided to its Members. Seminole engineering and consultant analyses estimate that SGS has a remaining useful life of at least another 30 years.

11. Putnam County, Florida, in which SGS is situated, was identified by *USA Today* as the poorest county in the State of Florida in 2015.[1] Putnam County

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[1] The Poorest County in Each State, *USA TODAY* (Jan. 10, 2015), *available at* http://www.usatoday.com/story/money/personalfinance/2015/01/10/247-wall-st-poorest-county-each-state/21388095/ (last visited Aug. 26, 2015).

has limited financial resources and is striving to improve its business and tax base. Putnam County has been designated as a “Florida Rural Enterprise Zone,” which provides for economic revitalization through tax incentives. The Governor also has designated Putnam County as a “Rural Area of Opportunity” because it is struggling to maintain, support, or enhance job activity, and to generate needed revenues for education, infrastructure, transportation, and safety. Portions of Putnam County also are within a U.S. Small Business Administration “Historically Underutilized Business Zone,” which allows small businesses to gain preferential access to federal procurement opportunities to promote economic development and growth in distressed areas. These state and federal designations reflect the tenuous economic status of the County and its residents.

12. SGS is one of the few major employers in Putnam County. SGS directly employs more than 300 people, and it requires hundreds of additional skilled contractors that work at the plant during maintenance outages and capital project implementation. Between 400 and 650 contractors worked at SGS during maintenance outages from 2012 to 2014. SGS is the largest taxpayer in Putnam County, paying more than $5 million in property taxes in both 2013 and 2014. If SGS is forced to close prematurely, or curtail its operations to comply with the 111(d) Rule, it will result in substantial layoffs. Putnam County will also suffer

substantial economic consequences due to those layoffs and due to the reductions in critical tax revenue.

13. Seminole also owns and operates MGS, an 810-MW (nominal) generating facility that burns natural gas as its primary fuel, with ultra-low sulfur fuel oil used as a back-up fuel. MGS began commercial operation in 2002 with a 500-MW NGCC unit, which consists of two natural gas-fired combustion turbines, two heat-recovery steam generators, and one steam turbine. In 2006, Seminole added 310-MW(nominal) of gas-fired peaking capacity, which can be operational in as few as eight minutes to meet state operating reserve requirements. In 2014, MGS' NGCC unit provided approximately 17 percent of Seminole's total energy needs. Like SGS, MGS has a remaining useful life of at least another 30 years.

14. MGS is located on the county line between Hardee and Polk counties in south central Florida, and employs 36 workers. Similar to Putnam County where SGS is located, Hardee County has been designated as a "Florida Rural Enterprise Zone" and as a "Rural Area of Opportunity." Portions of Hardee County also are within a U.S. Small Business Administration "Historically Underutilized Business Zone." Seminole paid more than $3 million annually in property taxes to Hardee County in both 2013 and 2014.

Summary of the 111(d) Rule

15. The 111(d) Rule establishes stringent CO_2 emission guidelines that states must follow to reduce CO_2 emissions from existing fossil fuel-fired power plants. Specifically, the Rule establishes: (a) unachievable CO_2 emission performance rates for two subcategories of existing power plants – steam generating units (including coal-fired boilers) and stationary combustion turbines (including natural gas-fired combined cycle units) – that EPA has nonetheless determined represent the best system of emission reduction for existing fossil fuel-fired power plants; (b) state-specific rate-based and mass-based CO_2 emission goals based on the unachievable subcategory rates and the state's 2012 generation mix; and (c) standards and requirements for the development, submittal, implementation, and enforcement of state compliance plans that establish emission standards or adopt other measures at least as stringent as the subcategory-specific performance rates or state goals. While the Rule's compliance period begins in 2022, and final standards must be achieved by 2030, regulated entities must begin taking steps well in advance of those deadlines – many immediately – if they are to comply by the specified deadlines.

16. As stated above, the Rule assigns a uniform performance rate for each existing coal-fired and natural gas-fired electric generating unit (except excluded combustion turbines) to reduce CO_2 from existing power plants, measured in terms

of pounds of CO_2 emitted for every net megawatt hour, or lbs CO_2/MWh-net. For existing steam generating coal-fired units like SGS, the performance rate is 1,305 lbs CO_2/MWh-net. For natural gas combined-cycle units like those at MGS, the performance rate is 771 lbs CO_2/MWh-net.

17. The Rule also sets forth statewide rate- and mass-based emission goals for each state calculated from the weighted aggregate of emission performance rates applicable to the state's existing coal-, gas- and oil-fired power plants. Florida's final rate-based CO_2 emission performance goal for 2030 is 919 lbs CO_2/MWh-net, and its mass-based goal for existing affected units is 105,094,704 short tons of CO_2.

18. Although the *final* state goals are not effective until 2030, the 111(d) Rule also establishes a "glide path" with increasingly stringent interim emission reduction requirements and average interim performance rates and goals for the 2022 to 2029 compliance period. Individual units must comply with both the interim and final requirements.

19. States may directly impose source-specific emission standards or requirements, or they may adopt other measures that achieve equivalent CO_2 emission reductions from the same group of existing electric generating units. Specifically, states may adopt an "emissions standards" plan that applies the source subcategory-specific performance rates to affected units or applies other rate or

mass-based standards to affected units that individually, or in the aggregate, achieve EPA's subcategory-specific performance rates, or state rate- or mass-based goals upon implementation. Affected units could pursue compliance measures such as heat rate improvements, investing in or transitioning generation to existing natural gas combined cycle, renewable, or nuclear electricity generation, or use of an emissions credit/allowance trading system. States also may adopt a "state measures" plan that includes, at least in part, measures imposed on entities other than existing electric generating units covered under the Rule, as well as a backstop of federally enforceable standards for individual power plants that are triggered if the state measures do not achieve the required emission reductions. States also may band together to adopt a multi-state plan applying either an "emissions standards" or "state measures" approach.

20. Regardless of which compliance approach states choose, emission reductions from affected electric generating units like those at SGS and MGS – individually, in the aggregate, or in combination with other measures taken by the state – must achieve the equivalent of the EPA-specified CO_2 emission performance rates by 2030, expressed via the state-specific rate- or mass-based goals. States must abide by the goals set by EPA; they are not free to adopt less stringent goals.

21. The apparent flexibility of the EPA process for crafting a state implementation plan creates the kind of uncertainty that is impracticable to plan for. Seminole is forced to make imminent planning decisions based on the most stringent, inflexible outcome possible, causing irreparable harm if other more flexible options become available at a later date under yet-to-be-determined rulemakings. States must submit at least an initial state plan to EPA by September 6, 2016. The 111(d) Rule allows states to seek an extension to September 6, 2018, to submit a final plan. EPA has pledged to review and approve state plans within a year of their submission. The State of Florida thus has until September 6, 2018, to submit a final plan so long as it submits an initial plan for compliance by September 6, 2016, and seeks an extension from EPA. It will not be clear what compliance methods will be ultimately adopted by the State – including whether a trading program will be established, the terms of any such program, or whether that program will be acceptable to EPA – until the plan is finalized and approved sometime in late 2018 or 2019. The State also has the discretion to choose not to adopt a trading program in favor of other methods of compliance. In short, there is likely to be no certainty about the shape of Florida's plan, whether trading will be available under it and, if so, on what terms trading will be available, for at least another four years.

The Rule's Effect on Seminole

22. Neither of Seminole's primary generating resources can meet the final 111(d) Rule's performance rate for existing steam generating coal-fired and natural gas combined cycle plants, nor can they meet the interim rate. As noted above, the performance rates are among the few key metrics finalized by EPA as of the August 3 signature. Accordingly, when dealing with forced current realities (i.e., required generation planning) as opposed to future possibilities under whatever type of plan Florida ultimately adopts, SGS would be permitted to emit no more than 1,305 lbs CO_2/MWh-net annually, and the MGS NGCC unit would be permitted to emit no more than 771 lbs CO_2/MWh-net annually, by 2030. The interim rates, which must be met by 2022, would permit SGS to emit no more than 1,534 lbs CO_2/MWh-net annually, and the MGS NGCC unit would be permitted to emit no more than 832 lbs CO_2/MWh-net annually. Over the past 5 years, SGS has emitted CO_2 at an average annual rate of 2,006 lbs CO_2/MWh-net, more than 700 lbs more per MWh-net than permitted by the 111(d) Rule when fully implemented. MGS has emitted CO_2 at an average annual rate of 905 lbs CO_2/MWh-net, more than 130 lbs more per MWh-net than permitted by the 111(d) Rule when fully implemented.

23. Because SGS and MGS cannot meet the uniform performance rates, the 111(d) Rule's strict requirements are placing all of Seminole's owned base-

load and intermediate generating facilities at SGS and MGS in jeopardy of being curtailed, shuttered, and/or replaced. In 2014, these assets provided 76 percent of Seminole's total energy needs. They are outfitted with state-of-the-art emission control systems and, having reached approximately half of their expected useful lives, are relatively new facilities, yet they cannot even come close to meeting the EPA's stringent 111(d) emission limits. Seminole has invested more than $530 million on state-of-the-art environmental control equipment at SGS since the plant came online in 1984 and more than $262.4 million has been invested since 2006 alone. Should the plant be shuttered and/or replaced, these investments will be lost.

24. There is no viable, adequately demonstrated environmental control system that Seminole can install at SGS or MGS to meet the new performance rates. The only means for SGS and the MGS NGCC unit to achieve the Rule's emission rates are: (i) curtailment of operations and replacement of the lost generation with lower-emitting generation (e.g., natural gas-fired units and renewable generation) obtained elsewhere; (ii) closure of the facilities entirely and replacement of the units with new natural gas-fired units and renewable generation; or (iii) purchase of emission reduction credits or allowances through a trading system that *might* be established pursuant to the 111(d) Rule.

25. The first two options explained in the previous paragraph (curtailment and replacement, or closure and replacement) will require the premature closure

and/or curtailment of SGS, and possibly the NGCC unit at MGS, at extraordinary cost to Seminole and its Members. More specifically, Seminole does not currently have sufficient owned or contracted lower-emitting generation capacity to replace all or part of the generation provided by SGS and the NGCC unit at MGS. Even if the NGCC unit at MGS could meet EPA's emission limits, it does not have sufficient capacity to replace lost generation from coal-fired SGS. The MGS NGCC unit has operated at an average capacity factor of 62 percent since 2012; this capacity factor leaves little room for Seminole to ramp up output at MGS to offset curtailed generation from the SGS coal-fired facility, as contemplated by EPA with their imposition of a 75 percent capacity factor requirement for gas-fired facilities. Seminole could also construct additional renewable generation, but it is not feasible to replace the baseload and intermediate generation provided by SGS and MGS wholly with intermittent renewable generation resources given their unpredictability and low capacity factor.

26. To comply with the final 111(d) Rule, then, Seminole must choose to construct new generation facilities or to contract for purchased power supply from third parties. In addition, Seminole must contract for natural gas to be used to fuel its own generation and potentially must contract for natural gas to be used at its purchased power resource facilities. Under any option, Seminole must make these irrevocable decisions *soon* as explained in the next paragraph. In addition,

Seminole must decide by early 2016 if it will build replacement generation resources or enter into one or more purchased power agreements. Considering the uncertainty created by the 111(d) Rule throughout the electric generation industry, it is questionable whether Seminole will be able to obtain any purchased power resources. If Seminole must construct its own gas-fired power plants by 2022, it must decide in 2016 whether to replace all generation at SGS and MGS or some portion of these resources, which is prior to any final regulatory direction provided by EPA or the State of Florida. These investments must be funded by consumers, resulting in extraordinary rate increases. Seminole's Members and their end-use consumers cannot withstand this added financial burden. If the Court invalidates the Clean Power Plan, these new investments will not be needed but consumers will have already suffered from the unnecessary and irreparable rate-increases.

27. To replace SGS alone, Seminole would have to choose and evaluate potential sites and apply for the requisite environmental and local permits, at a cost of approximately $2 million. As explained above, this irreparable effort and expense would need to begin by mid-2016. By the middle of 2018, Seminole also would have to contract to purchase generation equipment for the new plant at a cost of approximately $375 million. If the decision is made to replace the MGS NGCC unit by constructing an equivalently-sized new gas-fired combined cycle facility, Seminole would be required to spend an additional $150 million in the

same time frame.[2] Alternatively, if Seminole chooses to contract for the purchase of power and/or natural gas generating capacity, Seminole would have to negotiate and enter into the necessary contract(s) by mid-2018.

28. The total cost to Seminole of replacing 1,800 MW of capacity generated by SGS and the MGS NGCC unit is expected to be at least $1.8 billion. Replacing SGS's output would cost Seminole approximately $1.3 billion, and the cost of replacing the MGS NGCC unit's output would be approximately $500 million. These figures could be even higher if the gas-fired equipment and construction markets surge in response to the 111(d) Rule. Seminole would have to obtain financing, starting with powertrain payments of $525 million ($375 million to replace SGS and $150 million to replace the MGS NGCC unit) that would be made in mid-2018. Because Seminole will be carrying approximately $836 million in outstanding debt (as of December 2021) associated with the prematurely-retired SGS and MGS units when it obtains that additional financing, its credit rating also may be negatively affected. Credit rating downgrades extend across all aspects of a utility, negatively affecting contracts, financing, and rates. Seminole would have to accelerate the depreciation schedule for SGS from a 30-year remaining life to a significantly shorter useful life. Seminole's rates would be forced to increase to

[2] These costs represent only the initial power train equipment purchases that must be made by mid-2018, not the cost to replace SGS and MGS entirely.

cover the costs of new gas and/or renewable generation while continuing to pay for the sunk costs and outstanding debt associated with SGS and MGS.

29. Seminole also must decide before the end of 2016 whether to forgo planned investments in SGS, which are intended to maintain its efficient and environmentally-responsible operations. The uncertainty created by the 111(d) Rule thus creates another "roll of the dice" decision that must be made by Seminole. Seminole must choose now whether to spend additional money on improvements and risk losing the investments if the facility is prematurely retired, or choose not to spend the money and forgo the environmental benefits and efficiency gains that could be achieved.

30. Regardless of whether Seminole constructs new generation or enters into purchased power contracts with others to achieve compliance, Seminole would need to contract to increase its gas transportation capacity (via pipeline) before the end of 2016. The cost of constructing a gas pipeline to serve new gas-fired units is estimated to cost more than $80 million, $8 million of which may need to be paid before the end of 2016 to initiate the construction process. The enormous cost of the required investments – completely unnecessary and imprudently made if the Rule is eventually overturned – would be unrecoverable from the United States even if the 111(d) Rule is vacated. It is important to note that all of the additional

costs described above are on top of and in addition to the costs required to meet expected future demand for our Members.

31. The third option for compliance described above – purchase of emission reduction credits or allowances under a 111(d) Rule-compliant trading program – will not even be available to Seminole *unless* Florida adopts such a system. Seminole will not know with any certainty whether such trading will be available until late 2018 or in 2019, because the state plan requires development and EPA approval, both of which are time consuming. As noted above, Seminole will need to make decisions and commit to significant expenditures starting in 2016 regarding the generation resources that will be online in 2022 and beyond. It does not have the luxury of waiting to see if Florida adopts a trading program or if that program will provide sufficient credits or allowances, at economic prices, to allow the continued operation of SGS and the NGCC unit at MGS.

32. Seminole is a not-for-profit cooperative that cannot absorb the enormous costs of constructing a lower-emitting generating facility or contracting for lower-emitting generating capacity without passing along those costs to its Members. Premature closure of SGS, and potentially the NGCC unit at MGS, and the inability of Seminole to replace that generating capacity at a cost that would be affordable to Seminole's Members will have significant detrimental impacts on Seminole and its Members' consumers: (1) SGS's approximately 300 employees

will lose their jobs (and hundreds of contract-work opportunities will also be lost); (2) Seminole will no longer operate in its current form, having lost its principal generating unit(s); (3) Seminole will lose an annual multi-million dollar revenue stream from a contract with Continental Building Products ("Continental"), under which Continental purchases synthetic gypsum (a byproduct of combustion, produced by SGS's environmental control systems) and recycles that product to make wallboard; (4) Seminole's rates will increase and may no longer be competitive with other utilities in the state, driving much needed economic development out of Florida's rural areas; and (5) the entire objective of the federally-crafted rural cooperative structure will be undermined.[3]

33. Unless the 111(d) Rule is stayed pending judicial review, Seminole must take the immediate and irreversible steps described above causing Seminole and its Members' consumers to suffer immediate and irreparable harm. If the 111(d) Rule is later invalidated, without a stay, Seminole will have already committed to a combination of the following irreparable actions: premature closings and/or significant curtailment of its operating power generation facilities, significant expenditures on natural gas and/or renewable generation facilities, and

[3] *See* Kirk Johnson Decl., ¶¶ 6-9, 11 (discussing the purpose and formation of rural electric cooperatives).

new gas pipeline construction and/or purchase contracts.

Pursuant to 28 U.S.C. § 1746, I declare under the penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Executed: October 12th, 2015

By: ______________________

Lisa D. Johnson

ATTACHMENT O

TO

MOTION OF UTILITY AND ALLIED PETITIONERS FOR STAY OF RULE

Declaration of Michael L. Burroughs (Oct. 12, 2015)

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

Utility Air Regulatory Group,	)	
	)	
Petitioner,	)	
	)	
v.	)	Case No. __________
	)	
U.S. Environmental Protection Agency,	)	
	)	
Respondent.	)	

DECLARATION OF MICHAEL L. BURROUGHS

I, Michael L. Burroughs, declare:

1. I am the Senior Production Officer ("SPO") of Gulf Power Company ("Gulf Power" or the "Company"). As SPO, I oversee Gulf Power's electricity generation operations and, as part of our generation planning efforts, I rely on information and input from the Company's transmission planning group. I have been in my current role since August 2010. Prior to that, I served as the Plant Manager of Georgia Power's Plant Yates beginning in 2007. Overall, I have worked within the Southern Company system for twenty-four years. I hold a Bachelor's Degree in Mechanical Engineering from the University of Alabama at Birmingham.

2. In this declaration, I identify numerous impacts to Gulf Power, its employees, its customers, and its local communities if we are required to undertake the steps the Environmental Protection Agency ("EPA") itself has forecasted in its Regulatory Impact Analysis of the Clean Power Plan. Based on EPA's Integrated Planning Model ("IPM") analysis, the impacts to Gulf Power include:

- The premature closure of over 1,100 megawatts ("MW") of fossil fuel-fired units with a current value of over $1.4 billion, constituting approximately 58% of Gulf Power's generating capacity;
- Higher production costs and an insufficient reserve margin, resulting in increased customer costs of over $130 million in 2016-2017;
- Costs in excess of $50 million for needed transmission projects, with approximately $33 million in costs in 2016-2017;
- Costs in 2016-2017 of $98 million to compensate for impacts to the fuels program;
- Loss of approximately $3 million in annual property taxes used by local governments beginning in 2016; and
- Loss of approximately 260 full-time jobs in 2016-2017.

3. Based on EPA's results, and because it takes many years to plan and implement changes to our generating and transmission resources, Gulf Power would have to begin activities immediately in 2016 and 2017 regardless of the specifics of any state or federal plan ultimately adopted to implement the Clean Power Plan. This is because, according to EPA, the retirements identified by the IPM are already the current "best assessment of likely impacts of the [Clean Power Plan] under a range of approaches that states may adopt." EPA, Regulatory Impact Analysis 3-11 (Aug. 2015) ("RIA"), *available at* http://www3.epa.gov/airquality/cpp/cpp-final-rule-ria.pdf. Moreover, as explained below, many of these impacts could not be reversed once the changes to the generating and transmission resources have begun.

4. Gulf Power is a subsidiary of Southern Company, serving customers across Northwest Florida. Gulf Power delivers nearly half a million customers safe, reliable, and affordable electricity service generated from a full portfolio of energy resources, comprising four fossil and

renewable generating plants. As the SPO, I and my staff are charged with ensuring the reliability and cost-effectiveness of Gulf Power's generation.

5. Gulf Power is a vertically integrated, regulated utility that not only produces electricity but also ensures the safe, reliable transmission and distribution of that electricity to our customers.

6. Gulf Power has and applies tools to assess and project the status of our power plants and transmission network to ensure reliability and availability as part of an annual resource planning process.

7. Gulf Power has a long-range horizon for many of its planning decisions. Most of the activities we undertake require years, and sometimes decades, to plan and execute. Depending on the type of generation (combustion turbine, natural gas combined cycle ("NGCC"), nuclear, etc.), new generation plants require from four to seventeen years to obtain regulatory approvals, plan, site, design, permit, construct, and commission. For example, a new NGCC takes approximately seven to eight years to obtain regulatory approvals, engineer, procure, construct, and place in service. Accordingly, if a new NGCC were needed to be placed into service in 2022, activities to meet that projected in-service date would have to begin immediately. Likewise, identifying, developing, planning, and then building transmission projects can require years to implement, particularly when property rights for new power line corridors must be obtained. In sum, the nature of the utility planning process requires us to take actions well in advance of a forecasted event or need in order to ensure that we maintain our ability to provide the most cost-effective and reliable electric service possible to our customers.

8. I provide this declaration in support of the Utility Industry's motion to stay the EPA's "Carbon Pollution Emission Guidelines for Existing Sources: Electric Generating Units" ("Final

Rule" or "Clean Power Plan"). EPA, *Carbon Pollution Emission Guidelines for Existing Sources: Electric Generating Units* (signed Aug. 3, 2015), *available at* http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf.

9. I hereby rely upon all statements and analyses provided by Kim Greene, Southern Company's Chief Operating Officer, on behalf of the Southern Company system.

10. This declaration is based on my personal knowledge of facts and analysis conducted by Gulf Power and Southern Company staff and me.

SUMMARY OF EPA'S CLEAN POWER PLAN

11. On August 3, 2015, EPA promulgated its Final Rule under Section 111(d) of the Clean Air Act. The Final Rule establishes interim and final national "performance rates" for existing fossil fuel-fired steam boilers and for NGCCs. The interim performance rates, which apply from 2022 through 2029, are established as the emission of 1,534 lbs CO_2/MWh and 832 lbs CO_2/MWh for fossil fuel-fired steam boilers and NGCCs, respectively. Beginning in 2030 and thereafter, the fossil fuel-fired steam boiler and NGCC performance rates drop to 1,305 lbs CO_2/MWh and 771 lbs CO_2/MWh. EPA used these interim and final national performance rates to establish state-specific, rate-based and mass-based goals, which were calculated by applying the performance rates to each state's 2012 generation mix. EPA's goals for fossil fuel-fired generating units in Florida are shown in the table below.

EPA's Goals for Fossil Fuel-Fired Units in Florida

	Rate-Based Goal (lbs. CO_2/MWh)	**Mass-Based Goal (short tons)**
Interim (2022-2029)	1,026	112,984,729
Final (2030)	919	105,094,704

EPA'S REGULATORY IMPACT ANALYSIS

12. In performing its Regulatory Impact Analysis of the Final Rule, EPA relied on the IPM to define "a least cost way to achieve the state goals . . . ." RIA at ES-4. Through this modeling, EPA developed a "compliance solution" for each state—i.e., the set of plant retirements, shifts in utilization of remaining generation, and new generation that would demonstrate compliance with the Clean Power Plan's required reductions.

CONSEQUENCES IDENTIFIED IN EPA'S REGULATORY IMPACT ANALYSIS

13. Under EPA's compliance solution, Gulf Power must retire *over 1,100 MW of fossil fuel-fired units in 2016 alone*, as shown in the table below. With these retirements, 58% of Gulf's ownership in retail generation would be retired in 2016.

Gulf Power Retirements under EPA's Compliance Solution

Unit	Year	Net Summer Peak MW Capacity (Gulf Power Ownership Portion Shown in Parentheses)
Crist 4-7	2016	924
Daniel 1	2016	510 (255)

As described in Kim Greene's declaration, we have determined some of the immediate and irreparable consequences of these premature retirements for Gulf Power. Although I focus on those harms that would occur as a result of retirements in 2016, even if the retirements identified by EPA in its compliance solution did not occur until 2022 (the first year of the interim compliance periods), Gulf Power would suffer irreparable harm in the near-term given the decisions and actions that would be necessary now to prepare for those retirements.

Impacts to Reserve Margins

14. The retirements shown in EPA's compliance solution reflect Gulf Power retirements of over 1,100 MW in 2016, and overall Southern Company system retirements of over 8,000 MW in 2016. While Gulf Power has its own obligation to meet customer needs, the Company's generating and transmission resources are physically connected to and integrated with the rest of the Southern Company system, and balancing combined customer demand and generation is done at the system level.

15. The premature retirement of over 8,000 MW in 2016 would negatively impact the reserve margin of the Southern Company system. A reserve margin is a measure of the amount of resources available in excess of forecasted demand. Southern Company's long-term reserve margin is established at 15% and is necessary to maintain reliability on the system, taking into account risks due to non-normal weather, unit outages, and inherent inaccuracies in demand forecasts. EPA's compliance solution would dangerously reduce Southern Company's long-term reserve margin below the established 15% to 4.8% in 2016 and 2.9% in 2017. These drastically reduced reserve margins would have significant reliability and cost implications. Furthermore, the Company's response to these reliability and cost implications cannot be unwound, because once an electric generating unit is retired, it is not feasible to return the same unit to service.

16. The Southern Company system's reserve margin depends not only on physical generating assets but also on customer participation in what are referred to as "demand-side options." These demand-side options are agreements with some customers to interrupt some or all of their service when needed (for example, a factory with three production lines may agree that it will shut down one or more production lines for a certain time period when asked to do so).

17. If such demand-side options were no longer available, the Southern Company system's reserve margin would be negative in 2016 and 2017 under EPA's compliance solution. This

would mean there are not enough generation resources to match even forecasted demand under normal weather conditions, much less under extreme weather conditions. An example of demand-side options becoming unavailable is if the factory participant (described above) chooses to exit the program because its power was interrupted frequently rather than rarely.

18. The premature retirement of over 8,000 MW of generation in 2016 would also drive the Southern Company system's reliability far outside of common industry practice. One reliability measure used in the industry is to avoid having more than one customer electricity service interruption over a ten-year period due solely to having insufficient generation to meet customer firm demand. The Southern Company system currently has sufficient generation to be below this measure. However, the retirement of over 8,000 MW in 2016 would drive that measure for the Southern Company system to twenty-four events every ten years, or twenty-four times higher than common industry practice.

19. The retirements and generation shifts shown in EPA's compliance solution would also lead to an increase in generation production costs, because more expensive generation will need to operate to partially replace the less expensive generation that is retired or utilized less. In addition, there would be an impact on customers associated with the cost of unserved energy. Unserved energy is customer demand for electricity that cannot be met due to generation deficiencies. This unserved demand is manifested as controlled, temporary shut-off of electric service in a rotating manner to groups of firm load customers in order to maintain compliance with North American Electric Reliability Corporation ("NERC") standards. Customers with unmet demand suffer economic costs. The economic impact to Gulf Power customers from such higher production costs and unserved energy would be approximately $133 million during the 2016-2017 time period.

20. If these retirements occurred in 2022, the reserve margin impacts would be deferred until 2022. However, even if the retirements occurred in 2022, the Southern Company system would still have to begin taking action immediately in 2016-2017 to prepare for the retirements. For example, if the Southern Company system sought to replace the retired generation through the construction of NGCCs in order to reach the target planning reserve margin in 2022, the planning process would have to begin immediately, and there would be $158 million of expenditures in 2016-2017. Gulf Power Company's share of spending would be $30 million.

Impacts to Transmission

21. A preliminary screening analysis was performed by Gulf Power's transmission planning group to assess the impacts to the transmission system due to the unit retirements identified in EPA's compliance solution. I have received the results from Gulf Power's transmission planning group as detailed below. This is the type of information that is utilized as an input in the Company's planning process. The preliminary screening analysis used to determine the transmission system impacts, as well as associated transmission projects and estimated costs, was limited to power flow analyses developed with transmission planning models for the years 2016 and 2022 to monitor thermal and voltage constraints in our transmission system. Additional transmission analyses, such as dynamic analysis and assessments of off-peak system conditions, would need to be performed to identify a comprehensive set of transmission projects needed to maintain reliability. It would take many months to perform these additional transmission analyses, and thus they are not included in this declaration. It is anticipated that such analyses would likely identify additional, significant transmission impacts due to the unit retirements identified in EPA's compliance solution.

22. As a result of the unit retirements identified in EPA's compliance solution, a significant amount of replacement generating capacity will be needed to maintain resources adequate to

reliably serve the demand for electricity. For purposes of our preliminary screening analysis, we assumed this replacement generating capacity would have to be procured from third-party resources because neither Gulf Power nor the Southern Company system would be able to build sufficient generation to replace the missing capacity by the 2016 closure dates identified in EPA's compliance solution. Under these resource assumptions, our analysis showed that in order to accommodate the unit retirements identified in EPA's compliance solution, numerous transmission projects must be undertaken in Florida to maintain compliance with NERC Reliability Standards. Specifically, as identified in the table below, at least five additional transmission projects, including one new line and substation project, at a cost in excess of $54 million, will be necessary in Florida, $33 million of which would be expended in 2016-2017. These are conservative estimates for numerous reasons, and they do not account for unserved energy from transmission constraints. Furthermore, and most critically, due to lead times required to complete these transmission projects, the transmission projects cannot be placed in service by the unit retirement dates identified in EPA's compliance solution. The new line and substation project will require a minimum of three years to complete. Projects at existing lines and substations will take approximately one to three years to complete. As a result, there will be increased risk to system reliability until these projects can be completed. Once new construction projects have begun, because they involve acquisition of long-term property rights, they cannot be easily unwound.

Transmission Projects Necessary in Florida

Project Type	Number of Projects
New Line and Substation Projects	1
Existing Line and Substation Projects	4
Total	5

Impacts from Fuel Contracts and Inventories

23. Under EPA's compliance solution, across the Southern Company system as a whole, the operating companies will incur costs of approximately $950 million in the 2016-2017 timeframe due to the impact on our fuel contracts and fuel inventories. As referenced by Kim Greene, these include: (1) the incremental cost to reduce coal contract volumes, assuming diverting remaining coal shipments to other coal units whenever possible; (2) liquidated damages associated with transportation contract cancellations; (3) costs associated with other fuel-related impacts, such as incremental costs to reduce other materials' contract volumes, including limestone, gypsum, fuel oil agreements, and railcar leases; (4) costs to cancel firm transportation agreements for natural gas to retired units, assuming no remarketing capability; and (5) the increase in system production cost, which results from forcing coal units to operate in order to consume the retiring units' coal inventories (planned burn). Gulf Power will bear $98 million of these costs as identified below, and once contracts are cancelled, they cannot easily be reinstated. Even if some of these costs could be mitigated under force majeure, substantial impacts would clearly remain.

Costs to Gulf Power from Fuel Contracts and Inventories

Fuel Costs	Estimated Cost in 2016-2017 ($2015)
Coal Transportation Agreements	$10M
Additional Fuel Related Impacts	$60M
Gas Firm Transportation Cancellations	$8M
Coal Planned Burn	$20M
Total	**$98M**

Impacts to Local Economies

24. The retirement of the units defined in EPA's compliance solution would have immediate and irreparable impacts on local economies. In Florida alone, local communities served by Gulf Power will lose approximately $3 million in annual property taxes beginning in 2016. These tax dollars are used by local governments to help fund basic services from police and fire protection to sanitation and education.

25. In addition to the reduction in tax base, the 2016 retirements will result in approximately 260 direct job losses in Florida.

Remaining Useful Life

26. The premature retirement of Gulf Power's units identified in EPA's compliance solution will result in closure of units that otherwise would have been economic to continue operating for many years. Gulf Power has recently invested substantial capital resources in these units, primarily for compliance with other EPA regulations. The net book value of these assets plus the value of environmental projects already underway is over $1.4 billion as of July 2015.

Conclusion

27. Unless the Final Rule is stayed, EPA's compliance solution shows immediate and irreparable impacts on Gulf Power, its employees, its customers, and the local communities it serves. These impacts are caused by the retirement of significant generating capacity that EPA's model shows occurring in 2016, even though this capacity would otherwise serve Florida's electricity needs for many years. The retirements identified in EPA's compliance solution would negatively affect our customers and the communities that we serve by increasing their cost for electricity, risking reliability, dramatically reducing the tax base, and causing substantial job losses.

28. Direct impacts to Gulf Power in excess of $130 million in 2016-2017 result from the need to undertake new transmission projects (which could not be completed in 2016) and from the impacts to fuel contracts and inventories.

29. Even if the retirements identified in EPA's compliance solution for 2016 occur in 2022, Gulf Power would be required to take action and incur approximately $30 million in costs in 2016-2017 to ensure that it can continue to provide safe, reliable, and affordable electricity service.

Respectfully submitted,

Michael L. Burroughs
Gulf Power, Senior Production Officer

October 12, 2015

ATTACHMENT P

TO

MOTION OF UTILITY AND ALLIED PETITIONERS FOR STAY OF RULE

Declaration of Anthony S. Campbell (Oct. 12, 2015)

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

UTILITY AIR REGULATORY GROUP, et al

Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,

Respondent.

Case No. ______________

DECLARATION OF ANTHONY S. CAMPBELL IN SUPPORT OF MOTION TO STAY

I, Anthony S. Campbell declare:

1. I am the President and Chief Executive Officer (CEO) of East Kentucky Power Cooperative, Inc. (EKPC).

2. EKPC is a not-for-profit generation and transmission (G&T) cooperative based in Winchester, KY.

3. EKPC's mission and obligation under federal and state law is to provide safe, reliable, affordable electric power to the 16 electric distribution cooperatives that own EKPC.

4. EKPC generates electricity at three base load power plants fueled by coal (8 units) one peaking plant fueled by natural gas (9 units), and five landfill gas plants. EKPC also has a long term power supply contract for hydroelectric generation.

5. More than 65 percent of the power EKPC needs to serve its load is fueled by coal.

6. EKPC's total generating capacity is about 3,000 megawatts, and that power is delivered over a network of high-voltage transmission lines totaling about 2,800 miles.

7. EKPC employs about 700 people.

8. More than 1 million Kentucky residents and businesses in 87 counties depend on the power EKPC generates.

9. EKPC's 16 owner-member cooperatives serve mainly rural areas in the Eastern and Central two-thirds of Kentucky. EKPC and its member cooperatives exist only to serve their members.

10. Our electric cooperatives serve some of the most remote parts of Kentucky. The terrain in this region varies from rolling farmland in central Kentucky to mountains in the eastern portion. On average, our cooperatives have about 9 consumers per mile of power line, while investor-owned utilities average 37 consumers per mile and municipal utilities average 48 consumers.

11. We serve some of the neediest Kentuckians. The household income of Kentucky cooperative members is 7.4 percent below the state average, and 22 percent below the national average. Twenty of the 82 counties we serve are characterized as in "persistent poverty" by the U.S. Department of Agriculture.

EKPC'S CURRENT ENVIRONMENTAL COMPLIANCE

12. EKPC has invested over nearly 1.7 billion dollars to have one of the cleanest coal fleets in the country. The Spurlock 1 and 2 units are retrofitted with state of the art emissions controls for SO_2, NOx, Particulate Matter, Mercury and Acid Gases. The Spurlock 3 and 4 units are state of the art Circulating Fluidized Bed technology and are two of newest and cleanest coal units in the country.

13. Cooper unit 2 has been retro-fitted with a selective catalytic reduction unit to remove NOx from the flue gas stream and a dry flue-gas desulfurization unit to control SO_2.

14. Cooper unit 1 is in the process of being tied into Cooper unit 2's controls and will be controlled at the same levels as Cooper unit 2.

THE CLEAN POWER PLAN

15. On August 3, 2015, the United States Environmental Protection Agency (EPA) signed the final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (the Rule).

16. As promulgated, the Rule requires a drastic reduction in fossil fuel-fired generation in Kentucky. In Kentucky, the Rule requires more than a 36-percent reduction in carbon dioxide emissions from the 2005 levels by 2030, a costly and unexpected additional decrease of 27 percent from the proposed rule's aggressive 2030 goal.

17. The Rule directs states to establish interim steps to facilitate compliance with the interim goals. Although the states have some flexibility, EPA proposes that Interim Step 1 include 2022-2024, Interim Step 2 include 2025-2027 and Interim Step 3 include 2028-2029. EPA requires states to adopt Interim Step goals that ensure that the state meets its overall interim compliance goal (whether it is in rate or mass).

18. States must submit an implementation plan to EPA for approval. States have the option of creating a plan using EPA's CO_2 emissions rate goal or EPA's tons CO_2 mass goal. States also have an option of adopting a "state measures" plan which allows states to impose standards on units that are not otherwise impacted by the Rule. States adopting a "state measures" plan must include a federally enforceable backstop. Because EPA cannot enforce a "state measures" plan, the backstop ensures EPA can enforce CO_2 limits in the event the state does not meet the Rule's goals. Each of these options leads to a different optimal compliance plan for the state's utilities including EKPC, yet EKPC must

begin planning and execution of its compliance plans before the State plan is known.

19. EPA set September 6, 2016 as the deadline for states to submit implementation plans. States have the option of providing EPA with an initial submission on September 6, 2016 and obtaining a two year extension, provided they meet certain qualifications for the extension. States that obtain a two year extension must submit their implementation plans to EPA by September 6, 2018.

20. The emission rates (and necessarily the state's resultant mass tons goals) for steam generating units are not achievable by any existing coal-fired units. To meet these limits, all existing owners of coal-fired steam generating units will have to decrease their average CO_2 emissions by (a) shutting down some units, (b) running some or all fossil units much less each year, (c) immediately beginning the process of constructing replacement natural gas baseload generation, and/or (d) engaging in some form of market for procuring emissions rate credits or emission allowances. Today there is no market for the latter option available in Kentucky, and EKPC cannot know today whether such a market will be formed. Because the Rule requires EKPC to drastically overhaul its generation fleet before 2022, for EKPC to be in a position to comply with the Rule in 2022, planning decisions and investment must begin immediately.

THE RULE'S IMPACT ON EKPC

21. There is no viable technology or equipment modification to enable an existing EGU to meet the EPA's CO_2 emission standards. EKPC simply cannot meet the Rule's reduction targets without substantial modifications to the design and operation of its current generation portfolio. To comply, EKPC must reduce generation, partially or fully retrofit for natural gas firing, or cease generation at its Spurlock and Cooper Plants as early as 2022 and immediately commit an extraordinary and unexpected amount of capital to develop natural gas resources at these plants and at its Smith natural gas site. EKPC also must invest heavily in renewable assets in a state that has limited wind and solar renewable resources as established and documented by third party experts. The expenditures required are likely to exceed a $500 million dollars and the amount of stranded assets on the Spurlock and Cooper plants could be approximately $500 million dollars. In support of these statements, this Declaration will focus on three of the areas posing significant harm to EKPC, which will be <u>real</u>, <u>immediate</u> and <u>irreparable</u> if the Rule is not stayed.

22. The Rule ignores the historic, well documented long lead times inherent in electric utility development of new, modified and or reconstructed generation facilities, pipeline construction and transmission expansion. Because of these long lead times, EKPC cannot wait for the final outcomes from any other

litigation, the details of a state implementation plan, or any CO_2 trading market to be developed, before expending substantial sums on compliance. If the Rule is not stayed, EKPC will be immediately forced to make substantial and irreversible multi-million dollar financial commitments to retain the expertise to study, design and begin the approval processes to construct assets necessary to comply with the Rule, potentially including new natural gas pipelines. These new pipelines will be required to allow the Spurlock and Cooper units to be modified and/or reconstructed to permit conversion to, or co-firing with, natural gas in order to generate at much lower CO_2 emissions rates and enable compliance with the 2022 CO_2 emissions rate targets. Lead times for siting, design, engineering, state and federal regulatory approvals, state and EPA environmental permitting, condemnation proceedings, procurement, construction and commissioning are a minimum of 6 years for plant modifications alone, and up to 10 years for transmission and natural gas infrastructure changes. The Rule also forces EKPC to immediately begin the parallel and substantial expense of constructing new gas generation assets that are mandatory for EKPC's compliance with the Rule. Importantly, ALL of these expenditures will be incurred regardless of whether or not the state files a state implementation plan by September 6, 2016, or obtains an extension until September 6, 2018, as the initial compliance period will begin in 2022 no matter when a state submits its plan.

23. EKPC must decide now, even before a state implementation plan is submitted and inclusive of a possible extension until September 6, 2018, whether to make this $500 million plus dollar commitment to these modified and/or reconstructed assets and new gas resources. If EKPC commits now to this course of action, these decisions cannot be undone once the rule is vacated years from now. The construction of these natural gas facilities would be done only to comply with the Rule.

24. The financial burden of these investments will be felt by EKPC's member-consumers in the form of substantial and unexpected rate hikes. At a compliance cost of just $500 million, each end consumer in EKPC's system would be responsible for $1,000 in direct costs, plus financing costs and the potential cost of stranded assets. EKPC's consumers cannot withstand this added financial burden. If the Court invalidates the Rule, these new investments will not be needed but consumers will have already suffered from the unnecessary rate-increases.

25. Further compounding the risk of irreparable harm to EKPC is the amount of debt that the Rule puts at risk. EKPC will have to immediately begin borrowing the funds needed to construct new facilities. These new borrowings will total at least 85% of the cost of the new facilities, likely well over $500 million. At the same time, EKPC must continue to pay its outstanding debts, of which the

majority is owed to the Rural Utilities Service/Federal Financing Bank (RUS/FFB), even if the underlying assets are used much less or not at all. The rates in place today support repayment of that existing debt and will be necessary to continue to repay that debt. This combination of substantial new debt and continued repayment of old debt associated with assets no longer fully in use will require substantial new rate increases, thereby increasing the financial burden on EKPC's members, who are unable to afford substantial increases in their electric bills.

26. The anticipated coal retirements potentially forced by this rule also threaten to irreparably harm EKPC's owner-consumers. Reduced coal generating units impacts EKPC's ability to respond to unforeseen weather events and to be able to continue to provide reliable generation throughout the year. Reliable and affordable electricity is particularly necessary during hot summer months and cold winter months. EKPC's owner-consumers need electricity most during winter and EKPC must ensure that adequate electricity is delivered to the grid during those critical months or the health of its owner-members will be at risk.

Pursuant to 28 U.S.C. § 1746, I declare under the penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Executed: October 12th, 2015

By: Anthony S Campbell

Anthony S. Campbell

ATTACHMENT Q

TO

MOTION OF UTILITY AND ALLIED PETITIONERS FOR STAY OF RULE

Declaration of Robert Frenzel (Oct. 15, 2015)

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

UTILITY AIR REGULATORY GROUP, Petitioner, v. **UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,** Respondent.	))))))))))	Case No. __________

<u>DECLARATION OF ROBERT FRENZEL</u>

1. I am the Senior Vice President and Chief Financial Officer ("CFO") of Luminant Generation Company LLC ("Luminant"), a subsidiary of Energy Future Holdings Corporation ("EFH Corp.") that holds several companies engaged in the competitive electric power business in Texas.

2. Luminant is the largest producer of electricity in Texas. Luminant owns and operates twelve coal-fueled and seven gas-fueled steam electric generating units ("EGUs") in Texas that are subject to regulation under the U.S. Environmental Protection Agency's ("EPA") Section 111(d) Final Rule.

3. I joined EFH Corp. in 2009 and served as the senior vice president for corporate development, strategy, and mergers and acquisitions prior to beginning my current role in 2012. Before joining EFH Corp., I was a senior vice president in the investment banking division of Goldman Sachs & Co. While at Goldman Sachs, I was a member of the energy and power group and focused on strategic and financial transactions within the industry. Prior to Goldman Sachs, I was a manager and senior consultant in the strategy, finance, and economics practice at Arthur Andersen. I also served as a nuclear engineering officer and weapons officer in the United States

Navy. I resigned from active duty in 1998, but I remained in the Navy Reserves, where I was later promoted to lieutenant commander before resigning my commission in 2007. I earned a Bachelor's Degree in industrial engineering from Georgia Tech and a Master's of Business Administration from the University of Chicago Graduate School of Business.

4. As CFO of EFH Corp., I am familiar with the Texas electricity market and Luminant's business, day-to-day operations, financial matters, the value of its assets, and its underlying books and records. I am providing this declaration in support of the Utility Air Regulatory Group's ("UARG") motion to stay EPA's final rule establishing CO_2 emission guidelines for existing stationary sources—a rule that will have highly damaging and irreparable impacts on Luminant's operations, as described below. This declaration is based on my personal knowledge of fact and analysis conducted by Luminant staff and me.

SUMMARY OF IRREPARABLE HARMS CAUSED BY EPA'S RULE

5. EPA's Section 111(d) Rule will have severe and detrimental impacts on Luminant's operations. As detailed below, these harms are already occurring or, based on EPA's own projections, will occur as early as 2016—before judicial review of the rule can be completed. In summary, EPA's rule:

a. Incentivizes the otherwise uneconomic construction of new generation to the detriment of Luminant's operations and the value of its existing assets;

b. Creates a regulatory overhang that prevents Luminant from engaging in efficient operations, planning, maintenance, and investment in its generating units and the mines supporting those units;

c. Renders several of Luminant's electric generation units uneconomic and forecasts the shutdown of those assets;

d. Projects a significant reduction in generation (and therefore profitability) as early as 2016 for units that are not forecast as shutdown.

6. Each of the above enumerated harms will be experienced in advance of the Final Rule's emission limitations becoming effective in 2022 and will be irreversible. The Final Rule, unless it is stayed immediately, will cause substantial operational and financial harm to Luminant and its existing assets regardless of whether the rule is ultimately found to be illegal.

7. Luminant operates its EGUs in a highly competitive marketplace in which the price of electricity—and ultimately Luminant's profitability—is set by the available supply of generation and its associated marginal costs, which are largely fuel, at a given level of demand. Low cost fuel and operating efficiencies are the hallmarks of a sustainable, profitable business. Any regulation that upsets the current or proposed balance of supply and demand for electricity in the state could cause immediate, near-term, and long-term irreparable harm to the existing electric generators in Texas.

8. These imminent harms are more specifically described as follows:

a. First, the rule changes the Texas power sector to the significant harm of Luminant's operations and the value of its assets. The prospect of EPA's CO_2 limitations taking effect is already distorting the market by incentivizing the build-out or expansion of generation from renewable energy sources and lower-CO_2 emitting natural gas sources. While these new generation assets have high up-front costs, once developed, this generation operates at a lower cost than Luminant's units and displaces our units in the competitive market place. Further, once new generation is developed, it will continue to operate regardless of whether the rule is ultimately found to be illegal. As a result, Luminant will experience substantial harm that cannot later be reversed well before EPA's CO_2 limits take effect.

b. Second, EPA's rule presently creates a regulatory overhang that is preventing Luminant from engaging in its normal generation operations, maintenance, planning, and investment. The cloud of uncertainty regarding the value and future economic viability of Luminant's generating assets inhibits investment in its mining and generation assets, which translates to lowering generation reliability and/or raising fuel costs. These scenarios lower near-term revenues or increase costs prior to the rule's implementation period and cause irrecoverable financial loss for the company.

c. Third, EPA's own modeling predicts multiple Luminant units are uneconomic under the rule and forecasts the shutdown of those generation units. EPA clearly believes these units are uneconomic under the rule. The shutdown of Luminant's units would not only cause Luminant significant financial harm, but it would cause a ripple effect in the surrounding communities, which are particularly susceptible to economic harms, and the permanent loss of a diverse energy mix for Texas. Once shutdown, it would be extremely difficult to recover these assets should the rule be struck down by the courts.

d. Fourth, for those Luminant units that EPA does not predict will actually shut down, EPA nonetheless projects a significant reduction in generation as early as 2016 under both its "rate-based" and "mass-based" approaches. It is not economically practical nor operationally efficient to operate these assets for long periods of time at reduced, inefficient capacity factors that EPA projects. The loss of production from Luminant's units would cause substantial and negative financial impacts to the company, including stranded assets and lost revenue, as well as job and skill losses that could not be recovered.

LUMINANT'S OPERATIONS AND ECONOMIC IMPACT

9. Luminant owns and operates over 13,700 megawatts ("MW") of installed generation capacity in Texas. This includes approximately 8,000 MW fueled by lignite and subbituminous coal. Luminant's generating portfolio is made up of 58% coal (including approximately 2,200 MW of new coal generation that came online in 2009 and 2010), 17% nuclear, and 25% natural gas. Luminant employs approximately 4,000 full-time employees and contracts with independent contractors that provide approximately 2,000 contractors to work at Luminant's plants and mines in the state of Texas. Luminant spends approximately $2.5 billion annually in the form of salaries, taxes, fuel, maintenance, and other operating and capital expenditures, and its impact on gross state product and gross domestic product is substantial.

10. Luminant's generation represents approximately 1.5% of all electricity generated in the United States annually. In Texas, in 2014, Luminant contributed approximately 20% of the electricity dispatched to Texas consumers and businesses by the Electric Reliability Council of Texas ("ERCOT"), the independent system operator that manages the state's unique competitive power market and the electric power grid that serves the majority of the state. The ERCOT market is a "power island" contained within Texas and separated from neighboring interconnections by asynchronous ties that limit imports and exports to and from the ERCOT market. Approximately 98% of the electricity generated in the ERCOT market is consumed in the ERCOT market. Texas's economic growth (as measured by gross state product year-over-year growth) has been one of the highest in the United States for the period 2005-2015, and

Texas's electric consumption has followed its growth. The state of Texas relies upon access to affordable, reliable generation to continue to fuel its economic expansion and that of the United States. Luminant's generating units are critical to the reliable operation of the ERCOT grid, and ERCOT relies heavily on Luminant to meet the area's increasing demand. Just this summer, for example, the hourly demand on the ERCOT system broke the all-time peak record three times in one week.[1] Demand ultimately peaked at 69,783 MW on August 10, 2015,[2] with all Luminant plants available and supplying nearly 14,000 MW to the grid at the time.

11. Luminant's coal-fueled EGUs are located at five generating plants (Big Brown, Martin Lake, Monticello, Sandow, and Oak Grove) that produce approximately 8,000 MW of power used by approximately three million Texans across the state. Luminant's coal-fueled EGUs are "mine mouth" plants that rely on lignite mines located near the plants to provide lignite coal to fuel the generating units. Luminant operates eight lignite mines that provide fuel to its coal-fueled generating units (Beckville, Kosse, Liberty, Oak Hill, Tatum, Thermo, Three Oaks, and Turlington). Thus, there is a specific and co-dependent relationship between the Luminant coal-fueled EGUs and the lignite mines that source the coal for them.

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[1] ERCOT, *ERCOT System Breaks 69,000 MW in Hourly Peak Demand for the First Time Ever* (Aug. 10, 2015), http://www.ercot.com/news/press_releases/show/73057.

[2] *Id.*

Luminant's Coal Units & Associated Mines

Plant	Operating Capacity (MW)	County	Associated Lignite Mines
Big Brown	1,150	Freestone	Turlington
Martin Lake	2,250	Rusk/Panola	Beckville, Tatum, Liberty, Oak Hill
Monticello	1,880	Titus	Thermo
Oak Grove	1,600	Robertson	Kosse
Sandow	1,137	Milam	Three Oaks

12. Luminant also owns and operates seven natural gas-fueled, steam-driven EGUs at four Texas plants (Graham, Lake Hubbard, Stryker Creek, and Trinidad), all subject to the rule, as well as ten diesel engine generators with a total installed capacity of 14 MW, which are not subject to the rule.

Luminant's Natural Gas Units

Plant	Operating Capacity (MW)	County
Graham	630	Young
Lake Hubbard	921	Dallas
Stryker Creek	675	Cherokee
Trinidad	244	Henderson
Morgan Creek	390	Mitchell
Permian Basin	325	Ward
Decordova	260	Hood
Diesel Engine Generators	14	Various

13. Additionally, Luminant owns and operates Comanche Peak, a nuclear power plant, located in Somervell County with an installed capacity of 2,300 MW.

14. Thus, Luminant has substantial experience and knowledge regarding the operation of various types of generating units, and my responsibilities as CFO encompass all of these units.

15. At all of its plants, mines, and offices, Luminant employs more than 4,000 employees, over 2,000 of whom work in mining operations and support.

THE SECTION 111(D) RULE'S REQUIREMENTS FOR TEXAS

16. EPA released the pre-publication version of its rule relying on Section 111(d) of the Clean Air Act (42 U.S.C. § 7411(d)) on August 3, 2015 ("Section 111(d) Final Rule"). The rule establishes nationwide emission performance rates (stated in pounds ("lbs.") of CO_2 per net megawatt hour ("MWh") of electricity generated) that apply to individual EGUs. EPA established a performance rate of 1,305 lbs. CO_2/MWh for fossil fuel-fired steam EGUs and a rate of 771 lbs. CO_2/MWh for natural gas combined cycle ("NGCC") units. Luminant's coal- and gas-fueled steam EGUs would be subject to the 1,305 lbs. CO_2/MWh performance rate. As discussed below, this rate could never be achieved at any of Luminant's units.

17. EPA also "converts" these performance rates into state "goals"—a "rate-based" goal (expressed in lbs. CO_2/MWh) and a "mass-based" goal (expressed in short tons). EPA did this by applying a weighted average of the individual unit performance rates to a state's generating mix of coal, natural gas, and other fossil fuel generating units. EPA's goals for Texas are shown in the table below.

EPA's "Goals" For Texas Compared to Baseline

	Rate-Based Goal (lbs. CO_2/MWh)	Mass-Based Goal (tons)
2012 Baseline	1,566	240,730,037
2022-2029 Interim Goal	1,188	208,090,841
2030+ Final Goal	1,042	189,588,842

Under these goals, Texas is required to reduce CO_2 emissions by 51.1 million tons per year by 2030. The 2030 Texas target requires a 33.5% reduction of Texas's CO_2 emission rate.

18. The regulation of CO_2 differs significantly from that of other emissions in several respects. CO_2 is naturally occurring in the environment and does not have direct effects on human health. And unlike for other emissions, add-on control equipment and other technologies are not effective means of reducing CO_2 emissions from existing sources. Instead, EPA identifies increases in generating unit efficiency as the primary mechanism for CO_2 reductions from units themselves. Beyond efficiency improvements, EPA does not identify any technologically available method of reducing CO_2 emissions at existing EGUs, and, therefore, adaptations of the EGUs will not result in the required reductions. As EPA acknowledges, CO_2 is not the result of impurities in the fuel and is an "unavoidable product" of combusting fuel to generate energy. Final Rule at 136. As a result, EGUs must reduce their productive service in order to achieve the CO_2 reduction goals required under EPA's Section 111(d) Rule. It is EPA's intention, fully articulated, that these units be unable to perform their function. According to EPA, under the Final Rule, "an EGU can either directly replace its generation, or simply reduce its generation, and in the latter case, the integrated grid . . . will result in entities providing replacement generation." Final Rule at 624.

EPA'S PERFORMANCE RATES WOULD REQUIRE THE SHUT DOWN OF LUMINANT'S UNITS

19. EPA's emission performance rate for fossil-fueled EGUs is simply not achievable, nor will it ever be achievable. Luminant's EGUs, like all other fossil fuel EGUs in the country, operate at rates significantly higher than EPA's performance rate. The table below shows the actual CO_2 rate for Luminant's coal-fueled EGUs in 2014 and estimates that each unit will be required to have at least a 50% reduction in emission rate to be in compliance with EPA's goals for Texas.

Actual Achieved CO_2 Performance Rates For Luminant Units

Unit / Plant	CO_2 Emission Rate (2014) (lbs. CO_2 / Net MWh)	Required Compliance Reduction to Meet Goal (%)[3]
Big Brown	2,301	55%
Martin Lake	2,388	56%
Monticello	2,409	57%
Sandow 4	2,345	56%
Sandow 5	2,131	51%
Oak Grove	2,184	52%

20. Thus, and as demonstrated below, these Luminant units will ***never*** be able to lower their CO_2 emission rate to comply with the unit performance rate promulgated by EPA in the Section 111(d) Final Rule. The only measure identified by EPA in the Final Rule by which an individual EGU could improve its performance rate is through an increase in generating unit efficiency (*i.e.*, making improvements that would enable the unit to produce more electricity with the same amount of fuel). Decreasing generation does not improve the units' CO_2 *rate* because any

[3] Texas's state-specific goal for 2030 and beyond is 1,042 lbs. CO_2/MWh.

decrease in actual CO_2 emissions from burning less fuel would also lower the output of the unit—and thus the CO_2 emitted *per megawatt hour* would be largely unaffected. In fact, because combustion units, like Luminant's, are designed to operate most efficiently at full load, lowering production would likely result in a decrease in efficiency and an *increase* in lbs. CO_2/MWh.

21. As part of its comments on EPA's proposed rule, Luminant engaged the engineering firm Burns & McDonnell ("BMcD") to conduct a technical assessment of EPA's "building block 1," requiring increases in efficiency, as applied to its units. Based on the assessment conducted, Luminant's best performing units could achieve *at best* less than 1% improvement in heat rate (which would correspond to a 1% reduction in lbs. CO_2/MWh). EPA itself only assumes that Texas coal-fueled EGUs can achieve a 2.3% emissions rate improvement (not the 50% that would be required for Luminant's units to be in compliance) under building block 1. The table below shows the substantial amounts of CO_2 reductions that must be achieved under the rule to meet the Texas goal but that cannot be achieved through heat rate improvements at the EGUs themselves.

BMcD's Projection of Achievable Heat Rate Improvements

Unit / Plant	Actual 2014 lbs. CO_2/MWh	Reduction from 1% Heat Rate Improvement per BMcD (lbs. CO_2/MWh)	2030 CO_2 Goal Reduction Achieved from 1% Heat Rate Improvement (%)	Remaining Shortfall From 2030 Goal (lbs. CO_2/MWh)	Additional Reduction in lbs. CO_2/MWh Needed to Meet Texas 2030 Goal (%)
Big Brown	2,301	23	1.8%	1,236	54%
Martin Lake	2,388	24	1.8%	1,322	55%
Monticello	2,409	24	1.8%	1,343	56%
Sandow 4	2,345	23	1.8%	1,280	55%
Sandow 5	2,131	21	2.0%	1,068	50%
Oak Grove	2,184	22	1.9%	1,120	51%

22. In addition, Luminant's natural gas-fueled steam EGUs could never meet the CO_2 reduction required by EPA's final performance goal. Luminant's natural gas-fueled steam EGUs currently produce between 1,400 lbs. and 1,700 lbs. CO_2/MWh. Neither a 1% or 2.3% heat rate improvement would achieve the reductions required.

23. Under EPA's performance rate for EGUs, Luminant's coal-fueled and natural gas-fueled EGUs would thus be forced to shut down completely.

EPA'S RULE IS CAUSING IMMEDIATE, IRREPARABLE HARM TO LUMINANT

EPA's Rule Creates Artificial Incentives that are Disrupting the Competitive Market

24. Even though the final rule does not require CO_2 reductions until 2022, the rule is presently creating anomalies in the Texas power market to Luminant's competitive disadvantage. For example, even before the rule became final, market participants were expecting dramatic shifts in generation away from coal-fueled units and to natural gas and renewable units in order to comply with the rule, and this incentivized the additional build out of natural gas and

renewable generation that would not otherwise be economic in ERCOT but for the *prospect* of EPA's state goal taking effect in the future. This shift will only become more pronounced in the immediate and near-term under the final rule. With the rule now finalized, changes in the market caused by the prospect of future shutdown or reduction of generation from Luminant's fossil generation will accelerate the incentives for new generation and cannot be prevented without a stay of the rule.

25. New renewable plants have high upfront capital costs (and are partially subsidized by Federal Tax incentives). Customers will ultimately have to provide an adequate profit to compensate for construction of new generation, thereby raising costs for consumers. This is also true for natural gas-fueled generation. However, this additional capacity on the market—which generally operates at lower marginal cost than Luminant's coal-fueled EGUs once the significant construction costs are expended—artificially lowers the wholesale price of power within ERCOT and results in lost revenue for Luminant. Furthermore, the Final Rule actually includes "early" incentives for development of new renewable generation in advance of the 2022 interim CO_2 reduction goals, and it is likely that this trend will be accelerated to accommodate planning and construction lead-times, and that is certainly EPA's intent. Once these units are built, they will continue to operate to the detriment of existing fossil units even if the rule is ultimately found to be illegal and the CO_2 limits do not go into effect. Thus, well before the CO_2 limits in the rule take effect, Luminant will experience irreparable and irreversible harm from the rule and that harm will persist even if the rule is ultimately found to be illegal.

26. The timeframe provided under EPA's Section 111(d) Final Rule incentivizes Texas's energy sector to take action immediately, otherwise it risks non-compliance with the rule in the future. As demonstrated below, EPA projects a massive increase in solar generation in the state,

beyond that which would otherwise be developed without the Final Rule, which the state and Texas generators must begin planning for now.

EPA's Solar Projections for Texas Needed To Comply With Section 111(d) Final Rule

	2012 Baseline (MWh)[4]	2030 Projected Solar Generation (MWh)[5]	Increase (MWh)	Increase (%)	Average land required (acres)
Rate-Based Approach	115,216	30,105,512	29,990,296	26,000%	131,000
Mass-Based Approach	115,216	33,911,475	33,796,259	29,300%	147,000

A vast majority of the increase in solar generation would come from *new* solar capacity. Specifically, of the 29,990,296 MWh increase under the rate-based approach, EPA projects Texas will generate 29,449,096 MWh of that increase from 15,421 MW of new solar capacity by 2030. Of the 33,911,475 MWh increase under the mass-based approach, EPA projects 33,085,598 MWh will be generated from 17,325 MW of new solar capacity by 2030. In 2012, by EPA's numbers, Texas generated only 115,216 MWh from solar. The land area required for such a massive increase in solar capacity (using an established range of 7 to 10 acres per MW) would range from 107,947 acres to 154,210 acres (rate-based goal) or 121,275 acres to 173,250 acres (mass-based goal), not accounting for the area or substantial cost required to develop additional transmission facilities, roughly 1/5th the size of the entire state of Rhode Island. For Texas to develop and utilize such a significant increase in solar, it will cost billions of dollars and

[4] EPA, *Clean Power Plan Final Rule Technical Documents*, http://www2.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents (last updated August 13, 2015) (data from "Data File: Goal Computation Appendix 1-5").

[5] EPA, *Analysis of the Clean Power Plan*, http://www2.epa.gov/airmarkets/analysis-clean-power-plan (last updated Oct. 15, 2015) (data from "Rate Based analyses of the CPP" and "Mass Based analyses of the CPP" IPM Run Files).

a significant increase in power prices to consumers. And, in practice, these deadlines kick in much earlier, with EPA artificially incentivizing the development of renewable energy between now and 2022.

27. Even if it were possible to build this much new renewable generation, the electricity sector in Texas would need to undertake a massive transmission build-out. A build-out of this magnitude would cost billions of dollars and require immediate planning to begin. The recent expansion of Texas's transmission system—the Competitive Renewable Energy Zone ("CREZ") project that was undertaken to accommodate the substantial renewable generation that Texas has already developed—took "years to undergo the regulatory process, siting, easement acquisition and construction to develop transmission facilities."[6] The CREZ project took eight years and nearly $7 billion to build approximately 3,600 miles of transmission lines capable of carrying a little over 18,000 MW of electricity.[7] To meet EPA's goals in the Section § 111(d) Final Rule, Texas's energy sector would need to begin the process now of investing substantial amounts of time and money to develop the extensive transmission system that would be necessary to comply. Delaying this process until all legal proceedings are concluded would put Texas at risk for noncompliance were the rule to survive legal challenge and be implemented; on the other hand, moving forward with this complex process before legal challenges are resolved risks expending valuable public and private resources in vain and distracting the energy sector from pressing near-term needs and priorities.

[6] Daniel Cusick, *New Power Lines will Make Texas the World's 5th-Largest Wind Power Producer* (Feb. 25, 2014), http://www.eenews.net/stories/1059995041 (citing Robbie Searcy, an ERCOT spokeswoman).

[7] *Id.*; Pub. Util. Comm'n of Tex., CREZ Transmission Program Information Center (2010), http://www.texascrezprojects.com/overview.aspx.

The Regulatory Uncertainty Caused by the Rule Is Causing Inefficient Operations, Maintenance, Planning, and Investment

28. In the immediate term, EPA's rule is causing significant harm by creating unprecedented regulatory uncertainty, which prevents efficient operations, maintenance, planning, and investment.

29. Under the deadlines set by EPA, the State of Texas is required by September 6, 2016, to either submit a full state plan to EPA or request an extension in accordance with EPA requirements. As EPA itself notes, "there is considerable uncertainty with regard to the regulatory form and precise measures that states will adopt to meet the requirements." U.S. EPA, Regulatory Impact Analysis for the Clean Power Plan Final Rule 3-11 (Aug. 2015) ("RIA"). Although EPA provides for the opportunity to seek an extension for states that provide significant and detailed information on how they intend to implement the Rule, EPA itself has merely *proposed* a separate rule to provide guidance for states on their state plans and will not finalize that rule until summer of 2016. In the interim, this kind of unprecedented regulatory uncertainty from not knowing how EPA will finalize its direction to the states and how Texas legislators and regulators ultimately will respond to such direction is causing significant uncertainty beyond what we have seen with any other environmental rulemaking and, in turn, significant harm from the inability to plan.

30. Given the vast reach of the rule and the changes it would force, this uncertainty—in and of itself—is causing Luminant irreparable harm. For most environmental rules, the compliance obligation is well-understood and defined—for example, install a certain piece of emissions control equipment that would meet a certain emission rate. For EPA's Section 111(d) Final Rule, however, the situation is starkly different. Here, EPA established a rate without tying that rate to any "adequately demonstrated" emission control technology. As EPA notes in the

preamble to the rule, CO_2 emissions directly correlate to the productive capacity of an EGU—that is, without the combustion process that generates CO_2, the unit does not operate. It is not something that can be eliminated from the process. Further, it is not solely up to the EGU operator to decide how to comply; the state must decide how it will comply and how the EGUs will fit within its plan. Thus, business planning for this rule is fundamentally different than planning for other rules, and the rule is already impacting how Luminant manages its EGUs. For example, the company engages in multi-year planning for its fleet in order to allocate its limited operating and capital dollars to maximize returns. But without knowing what the compliance obligation will be for its units—whether a performance rate will be directly imposed by the state or a trading program created or some other actions required—it is impossible to do this basic planning in the most efficient manner. The power generation and mining businesses typically have long-dated assets and long lead-time investment timelines, and it would be illogical for Luminant to make a 10-year investment in a plant or mine that will have to shut down in 5 years, thereby stranding costs—particularly in a competitive market like ERCOT where formal mechanisms to recover these costs do not exist. The result of this regulatory uncertainty and overhang is lost opportunity and foregone investment for the company.

31. The precise concern here was very recently realized in EPA's Mercury and Air Toxics Standards ("MATS") rule, which also applied to Luminant's units. Various states and industry groups sought a stay of the MATS rule until all legal proceedings had been finalized, but the Court denied the motion to stay and the rule was allowed to move forward. Companies undertook billions of dollars of investment, shut down power plants, and reduced their labor force in efforts to comply with the rule. Luminant also spent significant sums on compliance planning and implementation efforts. Years after the rule was finalized and after the initial

compliance deadline, the U.S. Supreme Court found the rule to be unlawful. Yet, significant and irreparable harms resulting from compliance with an illegal rule had already occurred. Under EPA's Section 111(d) Final Rule, the energy sector is once again faced with undergoing immediate, significant changes, many of which will be irreversible, to comply with a rule that may ultimately be deemed unlawful many years down the road. This Rule, however, is infinitely more complex and raises a vast amount of additional uncertainty beyond that of the MATS rule, creating an extraordinary risk that the harms to Luminant will be even greater here. Where the MATS rule set emission rates that could be achieved with additional, albeit expensive controls, the Section 111(d) Final Rule is not predicated on any achievable control equipment or strategy except to reduce or cease operation completely. In essence, without a stay of the Section 111(d) Final Rule, EPA will be able to impose regulatory changes it seeks even though the rule may ultimately be found unlawful—in other words, the delay of litigation without a stay could give EPA the results it desires in a manner that it cannot achieve legally through legislation.

EPA's Rule Will Cause Imminent, Irreparable Harm to Luminant in the Form of Unit Closures and Derates

32. Luminant's coal-fueled and gas-fueled steam generating units are existing EGUs under the rule, and it is Luminant's belief that the rule will have substantial and immediate negative impacts on Luminant's business. The Section 111(d) Final Rule as issued by EPA is specifically designed to shut down or substantially decrease production from its coal-fueled EGUs, including Luminant's newest and most efficient coal-fueled EGUs, in order to decrease CO_2 emissions.

33. EPA says in its final rule that "[s]tates . . . could simply impose [the performance] rates on each affected EGU in their respective jurisdiction" in order to comply. Final Rule at 330. Were EPA's unit performance rates imposed on Luminant's EGUs, it is a certainty that all those units would be required to shut down because they cannot meet the unit performance rate either

by operational or technological means. EPA also says that it is "offering states alternative approaches to carrying out their obligations." *Id.* These are EPA's statewide goals, discussed above. EPA claims these state goals "expand the range of choices that states have in developing their plans." RIA at 3-5. But from Luminant's perspective, these are false choices. EPA expects many EGU owners to "reduce the generation of an EGU by substituting generation from a lower-emitting NGCC directly." Final Rule at 701. But that is no solution for Luminant, who owns no NGCCs. Instead, Luminant would have to rely on the "alternatives" provided by EPA, such as just reducing its generation, "reduc[ing] its generation and purchas[ing] replacement power from the market," or purchasing credits or allowances to offset continued generation. *Id.* at 698, 701. Luminant operates in a competitive generation market and relies upon its ability to maximize its generation to maximize its profitability. So, under any of the so-called alternatives, Luminant's units would be required to decrease production or cease operating altogether, and Luminant would be required to invest in generating assets owned by its competitors to keep its own units operating. This causes Luminant significant irreparable harm, particularly with respect to its newest EGUs (Oak Grove and Sandow 4), which have many more decades of useful operating life, but for which EPA is projecting significant production losses (as discussed below). Additionally, this would result in job and other economic losses in the Texas communities in which the plants operate.

34. In the event of significant lost production at Luminant's coal-fueled units, it will be necessary for Luminant to effectuate a corresponding decrease in production at its mines that provide coal to the EGUs. Following a decrease in production, Luminant would then be required to release a significant number of its employees who work in mining operations. Even if EPA's Section 111(d) Final Rule is ultimately found to be illegal, it is unlikely Luminant would be able

to restore its skilled workforce. Mining jobs are some of the highest paying jobs in the rural communities in which Luminant's mines are located, so it is unlikely the employees will be able to find comparable employment in those areas. As a result, many employees who are let go would be forced to move elsewhere to look for work. Additionally, many of Luminant's mining employees have been working for the company for decades and will prematurely retire in the face of a potential layoff. Therefore, Luminant would unnecessarily face a shortage of skilled employees that could not be adequately replaced.

35. Although the exact parameters of the requirements on individual sources are not yet known, EPA itself has modeled the impact of its "rate-based" and "mass-based" goals for Texas and has concluded that, ***as early as 2016***, either goal would result in the closure or substantial loss of production at Luminant's coal-fueled EGUs.

36. As part of its final rule, in order "to estimate the costs, benefits, and economic and energy market impacts of implementing the CPP guidelines, the EPA modeled two illustrative plan approaches, each at the state level, based on a rate-based approach and a mass-based approach." *See* RIA at 3-7. EPA did so "to reflect, to the extent possible, the scope and nature of the CPP guidelines." *Id.* at 3-10 to 3-11.

37. EPA modeled the two illustrative plan approaches using the Integrated Planning Model ("IPM"). IPM, in EPA's words, is "a state-of-the-art, peer-reviewed, dynamic linear programming model that can be used to project power sector behavior under future business-as-usual conditions and examine prospective air pollution control policies throughout the contiguous United States for the entire electric power system." *Id.* at 3-1. "EPA used IPM to project likely future electricity market conditions with and without the Clean Power Plan Final

Rule." *Id*. Luminant is unable to run the proprietary IPM model itself and, thus, can only review the modeling results that EPA has made available and EPA's conclusions.

38. Under the rate-based scenario, EPA projects that U.S. coal-fueled generation will "decline 12 percent in 2025." *Id.* at 3-26. By 2030, the U.S. coal-fueled fleet "generates 23 percent less than in the base case." *Id*. EPA predicts that, "[r]elative to the base case, about 23 GW of additional coal-fired capacity is projected to be uneconomic to maintain by 2025 under the rate-based illustrative scenario, increasing to 27 GW in 2030 (about 11-13 percent respectively of all coal-fired capacity projected to be in service in the base case)." *Id.* at 3-30.

39. Under the mass-based scenario, EPA projects a decrease in U.S. coal-fueled generation of 15% in 2025 and 22% in 2030. *Id.* at 3-26. "Under the mass-based scenario, about 29 GW of additional coal-fired capacity is projected to be uneconomic to maintain by 2025, increasing to 38 GW by 2030 (about 14-19 percent respectively of all coal-fired capacity projected to be in service in the base case)." *Id.* at 3-30.

40. As to Luminant's EGUs in particular, EPA's IPM modeling shows Monticello Units 1 and 2 as completely shut down in 2016 under all cases. These units generated 2,971,440 Net MWh of electricity in 2014[8] (and they are continuing to operate in 2015), and the loss of these units would cause substantial financial harm to the company, as well as harm to the community and company employees.

41. Further, EPA's IPM modeling predicts that other Luminant units, although not immediately shut down, will see significantly less production in 2016 as a result of the rule. The two tables below present data from EPA's IPM modeling. The tables compare a 2016 "base case" without the rule to a modeled 2016 case with the rule (under the rate-based and mass-based

[8] EIA, Form EIA-923 Detailed Data, http://www.eia.gov/electricity/data/eia923/index.html (last visited Oct. 8, 2015) (select "2014: EIA-923 Early Release*").

approaches). As these tables show, Luminant's Martin Lake, Oak Grove, Sandow 4, and Sandow 5 facilities will operate less in 2016, resulting in lost generation and lost revenue to the company, according to EPA's modeling. At an average wholesale power price of $25 to $35/MWh, using EPA's projections, Luminant stands to lose as much as $60 to $85 million in revenue and associated contribution margin from lost generation at these units in 2016 alone.

EPA's Projected Decrease in 2016 Generation Under CPP's Rate-Based Goals[9]

Plant / Unit	**Baseline 2016 Generation in GWh**	**Rate-based 2016 Generation in GWh**	**Decrease in Generation in GWh**
Martin Lake	17,424	15,916	1,508
Oak Grove	12,391	11,945	446
Sandow 4	4,190	3,943	247
Sandow 5	3,981	3,746	235

EPA's Projected Decrease in 2016 Generation Under CPP's Mass-Based Goals[10]

Plant / Unit	Baseline Generation in GWh	Mass-based Generation in GWh	Decrease in Generation in GWh
Martin Lake	17,424	16,898	526
Oak Grove	12,391	12,306	85
Sandow 4	4,190	3,943	247
Sandow 5	3,981	3,746	235

42. EPA notes that its IPM modeling does not include an interstate trading option and that "trading across states would provide EGUs with additional low cost abatement opportunity,"

[9] EPA, *Analysis of the Clean Power Plan*, http://www2.epa.gov/airmarkets/analysis-clean-power-plan (last updated Oct. 15, 2015) (data from "EPA Base Case for the Clean Power Plan" and "Rate Based analyses of the CPP" IPM Run Files).

[10] EPA, *Analysis of the Clean Power Plan*, http://www2.epa.gov/airmarkets/analysis-clean-power-plan (last updated Oct. 15, 2015) (data from "EPA Base Case for the Clean Power Plan" and "Mass Based analyses of the CPP" IPM Run Files).

RIA at 3-10, but trading would not be available and in place in 2016. Thus, irrespective of what may happen in 2022 and what options states may have for compliance, EPA's modeling predicts generation changes in 2016 as a result of the rule, and these changes cannot be altered or alleviated by trading or some other regulatory mechanism, which under even the best of circumstances would not be available until 2022 at the earliest. This is consistent with my conclusions that EPA's rule is already creating changes in the way units are developed and managed. As EPA's modeling reflects, the energy market has already begun reacting to the rule without the foresight of knowing what will happen in the future. EPA's own IPM model demonstrates that the Section 111(d) Final Rule, which does not require compliance until 2022, will begin impacting units' operations as early as 2016, causing irreparable harm.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct. Executed this 15 day of October, 2015.

Robert Frenzel
Senior Vice President and Chief Financial Officer
Luminant Generation Company LLC

ATTACHMENT R

TO

**MOTION OF UTILITY AND ALLIED PETITIONERS
FOR STAY OF RULE**

Declaration of R. Allen Reaves, Jr. (Oct. 13, 2015)

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

Utility Air Regulatory Group,	)	
	)	
Petitioner,	)	
	)	
v.	)	Case No. __________
	)	
U.S. Environmental Protection Agency,	)	
	)	
Respondent.	)	

DECLARATION OF R. ALLEN REAVES, JR.

I, R. Allen Reaves, Jr., declare:

1. I am the Senior Production Officer ("SPO") of Mississippi Power Company ("Mississippi Power" or the "Company"). As SPO, I oversee Mississippi Power's electricity generation operations and, as part of our generation planning efforts, I rely on information and input from the Company's transmission planning group. I have been in this role since August 2010. I began working within the Southern Company system thirty-four years ago. I have held numerous positions throughout the system, along with relevant positions at other utility operating companies. Prior to my current position, I served as manager of Plant Daniel beginning in September 2007. I hold a Bachelor's Degree in Mechanical Engineering from the University of Alabama at Birmingham.

2. In this declaration, I identify numerous impacts to Mississippi Power, its employees, its customers, and its local communities if we are required to undertake steps as outlined in the Environmental Protection Agency's ("EPA") Regulatory Impact Analysis of the Clean Power Plan. Based on EPA's Integrated Planning Model ("IPM") analysis, the impacts to Mississippi Power include:

- The premature shuttering of over 1,200 megawatts ("MW") of fossil fuel-fired units, constituting approximately 33% of Mississippi Power's generating capacity, with more than 850 MW with a current value of over $450 million identified for retirement in 2016 alone;
- Higher production costs and an insufficient reserve margin, resulting in increased customer costs of approximately $125 million in 2016-2017;
- Costs in excess of $50 million for needed transmission projects, with more than $10 million in costs in 2016-2017;
- Costs in 2016-2017 of $23 million to compensate for impacts to the fuels program;
- Loss of approximately $15 million in annual property taxes used by local governments beginning in 2016; and
- Loss of approximately 95 full-time jobs in 2016-2017 alone.

3. Based on EPA's results, and because it takes many years to plan and implement changes to our generating and transmission resources, Mississippi Power would have to begin activities immediately in 2016 and 2017 regardless of the specifics of any state or federal plan ultimately adopted to implement the Clean Power Plan. This is because, according to EPA, the retirements identified by the IPM are already the current "best assessment of likely impacts of the [Clean Power Plan] under a range of approaches that states may adopt." EPA, Regulatory Impact Analysis 3-11 (Aug. 2015) ("RIA"), *available at* http://www3.epa.gov/airquality/cpp/cpp-final-rule-ria.pdf. Moreover, as explained below, many of these impacts could not be reversed once the changes to the generating and transmission resources have begun.

4. Mississippi Power is a subsidiary of Southern Company, serving customers in Southeast Mississippi. Mississippi Power delivers nearly 187,000 customers safe, reliable, and affordable electricity service generated from a full portfolio of energy resources, comprising 19 fossil

electric generating units. As the SPO, I and my staff are charged with ensuring the reliability and cost-effectiveness of Mississippi Power's generation.

5. Mississippi Power is a vertically integrated, regulated utility that not only produces electricity but also ensures the safe, reliable transmission and distribution of that electricity to our customers.

6. Mississippi Power has and applies tools to assess and project the status of our power plants and transmission network to ensure reliability and availability as part of an annual resource planning process.

7. Mississippi Power has a horizon of forty years for many of its planning decisions. Most of the activities we undertake require years, and sometimes decades, to plan and execute. Depending on the type of generation (combustion turbine, natural gas combined cycle ("NGCC"), nuclear, etc.), new generation plants require from four to seventeen years to obtain regulatory approvals, plan, site, design, permit, construct, and commission. For example, a new NGCC takes approximately seven to eight years to obtain regulatory approvals, engineer, procure, construct, and place in service. Accordingly, if a new NGCC were needed to be placed into service in 2022, activities to meet that projected in-service date would have to begin immediately. Likewise, identifying, developing, planning, and then building transmission projects can require years to implement, particularly when property rights for new power line corridors must be obtained. In sum, the nature of the utility planning process requires us to take actions well in advance of a forecasted event or need in order to ensure that we maintain our ability to provide the most cost-effective and reliable electric service possible to our customers.

8. I provide this declaration in support of the Utility Industry's motion to stay the EPA's "Carbon Pollution Emission Guidelines for Existing Sources: Electric Generating Units" ("Final

Rule" or "Clean Power Plan"). EPA, *Carbon Pollution Emission Guidelines for Existing Sources: Electric Generating Units* (signed Aug. 3, 2015), *available at* http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf.

9. I hereby rely upon all statements and analyses provided by Kim Greene, Southern Company's Chief Operating Officer, on behalf of the Southern Company system.

10. This declaration is based on my personal knowledge of facts and analysis conducted by Mississippi Power and Southern Company staff and me.

SUMMARY OF EPA'S CLEAN POWER PLAN

11. On August 3, 2015, EPA promulgated its Final Rule under Section 111(d) of the Clean Air Act. The Final Rule establishes interim and final national "performance rates" for existing fossil fuel-fired steam boilers and for NGCCs. The interim performance rates, which apply from 2022 through 2029, are established as the emission of 1,534 lbs CO_2/MWh and 832 lbs CO_2/MWh for fossil fuel-fired steam boilers and NGCCs, respectively. Beginning in 2030 and thereafter, the fossil fuel-fired steam boiler and NGCC performance rates drop to 1,305 lbs CO_2/MWh and 771 lbs CO_2/MWh. EPA used these interim and final national performance rates to establish state-specific, rate-based and mass-based goals, which were calculated by applying the performance rates to each state's 2012 generation mix. EPA's goals for fossil fuel-fired generating units in Mississippi are shown in the table below.

EPA's Goals for Fossil Fuel-Fired Units in Mississippi

	Rate-Based Goal (lbs. CO_2/MWh)	**Mass-Based Goal (short tons)**
Interim (2022-2029)	1,061	27,338,313
Final (2030)	945	25,304,337

EPA'S REGULATORY IMPACT ANALYSIS

12. In performing its Regulatory Impact Analysis of the Final Rule, EPA relied on the IPM to define "a least cost way to achieve the state goals . . . ." RIA at ES-4. Through this modeling, EPA developed a "compliance solution" for each state—i.e., the set of plant retirements, shifts in utilization of remaining generation, and new generation that would demonstrate compliance with the Clean Power Plan's required reductions.

CONSEQUENCES IDENTIFIED IN EPA'S REGULATORY IMPACT ANALYSIS

13. Under EPA's compliance solution, Mississippi Power must retire over 1,200 MW of fossil fuel-fired units by 2020, as shown in the table below, which constitutes approximately 33% of Mississippi Power's generating capacity. Of that 1,200 MW, EPA predicts that *more than 850 MW will retire in 2016 alone.*

Mississippi Power Retirements under EPA's Compliance Solution

Unit	Year	Net Summer Peak MW Capacity (MPC Ownership Portion Shown in Parentheses)
Greene County 1	2016	262 (105)
Daniel 1	2016	510 (255)
Watson 5	2016	510
Greene County 2	2020	255 (102)
Watson 4	2020	265

As described in Kim Greene's declaration, we have determined some of the immediate and irreparable consequences of these premature retirements for Mississippi Power. Although I focus on those harms that would occur as a result of retirements in 2016, even if the retirements identified by EPA in its compliance solution did not occur until 2022 (the first year of the interim compliance periods), Mississippi Power would suffer irreparable harm in the near-term given the decisions and actions that would be necessary now to prepare for those retirements.

Impacts to Reserve Margins

14. The retirements shown in EPA's compliance solution reflect Mississippi Power retirements of over 850 MW in 2016, and overall Southern Company system retirements of over 8,000 MW in 2016. While Mississippi Power has its own obligation to meet customer needs, the Company's generating and transmission resources are physically connected to and integrated with the rest of the Southern Company system, and balancing combined customer demand and generation is done at the system level.

15. The premature retirement of over 8,000 MW in 2016 would negatively impact the reserve margin of the Southern Company system. A reserve margin is a measure of the amount of resources available in excess of forecasted demand. Southern Company's long-term reserve margin is established at 15% and is necessary to maintain reliability on the system, taking into account risks due to non-normal weather, unit outages, and inherent inaccuracies in demand forecasts. EPA's compliance solution would dangerously reduce Southern Company's long-term reserve margin below the established 15% to 4.8% in 2016 and 2.9% in 2017. These drastically reduced reserve margins would have significant reliability and cost implications. Furthermore, the Company's response to these reliability and cost implications cannot be unwound, because once an electric generating unit is retired, it is not feasible to return the same unit to service.

16. The Southern Company system's reserve margin depends not only on physical generating assets but also on customer participation in what are referred to as "demand-side options." These demand-side options are agreements with some customers to interrupt some or all of their service when needed (for example, a factory with three production lines may agree that it will shut down one or more production lines for a certain time period when asked to do so).

17. If such demand-side options were no longer available, the Southern Company system's reserve margin would be negative in 2016 and 2017 under EPA's compliance solution. This would mean there are not enough generation resources to match even forecasted demand under normal weather conditions, much less under extreme weather conditions. An example of demand-side options becoming unavailable is if the factory participant (described above) chooses to exit the program because its power was interrupted frequently rather than rarely.

18. The premature retirement of over 8,000 MW of generation in 2016 would also drive the Southern Company system's reliability far outside of common industry practice. One industry measure of sufficient generating resources is to avoid having more than one customer electricity service interruption over a ten-year period. The Southern Company system currently has sufficient generation to be below this measure. However, the retirement of over 8,000 MW in 2016 would drive that measure for the Southern Company system to twenty-four events every ten years, or twenty-four times higher than common industry practice.

19. The retirements and generation shifts shown in EPA's compliance solution would also lead to an increase in generation production costs, because more expensive generation will need to operate to partially replace the less expensive generation that is retired or utilized less. In addition, there would be an impact on customers associated with the cost of unserved energy. Unserved energy is customer demand for electricity that cannot be met due to generation deficiencies. This unserved demand is manifested as controlled, temporary shut-off of electric service in a rotating manner to groups of firm load customers in order to maintain compliance with North American Electric Reliability Corporation ("NERC") standards. Customers with unmet demand suffer economic costs. The economic impact to Mississippi Power customers

from such higher production costs and unserved energy would be approximately $125 million during the 2016-2017 time period.

20. If these retirements occurred in 2022, the reserve margin impacts would be deferred until 2022. However, even if the retirements occurred in 2022, the Southern Company system would still have to begin taking action immediately in 2016-2017 to prepare for the retirements. For example, if the Southern Company system sought to replace the retired generation through the construction of NGCCs in order to reach the target planning reserve margin in 2022, the planning process would have to begin immediately, and there would be $158 million of expenditures in 2016-2017. Mississippi Power Company's share of spending would be $19 million.

Impacts to Transmission

21. A preliminary screening analysis was performed by Mississippi Power's transmission planning group to assess the impacts to the transmission system due to the unit retirements identified in EPA's compliance solution. I have received the results from Mississippi Power's transmission planning group as detailed below. This is the type of information that is utilized as an input in the Company's planning process. The preliminary screening analysis used to determine the transmission system impacts, as well as associated transmission projects and estimated costs, was limited to power flow analyses developed with transmission planning models for the years 2016 and 2022 to monitor thermal and voltage constraints in our transmission system. Additional transmission analyses, such as dynamic analysis and assessments of off-peak system conditions, would need to be performed to identify a comprehensive set of transmission projects needed to maintain reliability. It would take many months to perform these additional transmission analyses, and thus they are not included in this declaration. It is anticipated that such analyses would likely identify additional, significant transmission impacts due to the unit retirements identified in EPA's compliance solution.

22. As a result of the unit retirements identified in EPA's compliance solution, a significant amount of replacement generating capacity will be needed to maintain resources adequate to reliably serve the demand for electricity. For purposes of our preliminary screening analysis, we assumed this replacement generating capacity would have to be procured from third-party resources because neither Mississippi Power nor the Southern Company system would be able to build sufficient generation to replace the missing capacity by the 2016 closure dates identified in EPA's compliance solution. Under these resource assumptions, our analysis showed that in order to accommodate the unit retirements identified in EPA's compliance solution, numerous transmission projects must be undertaken in Mississippi Power's service territory to maintain compliance with NERC Reliability Standards. Specifically, as identified in the table below, at least four additional transmission projects, including one new line and substation project, at a cost in excess of $50 million, will be necessary in Mississippi, more than $10 million of which would be expended in 2016-2017. These are conservative estimates for numerous reasons, including that they do not account for unserved energy from transmission constraints. Furthermore, and most critically, due to lead times required to complete these transmission projects, the transmission projects cannot be placed in service by the unit retirement dates identified in EPA's compliance solution. The new line and substation project will require from five to seven years to complete. Projects at existing lines and substations will take approximately two to five years to complete. As a result, there will be increased risk to system reliability until these projects can be completed. Once new construction projects have begun, because they involve acquisition of long-term property rights, they cannot be easily unwound.

Transmission Projects Necessary in Mississippi

Project Type	Number of Projects
New Line and Substation Projects	1
Existing Line and Substation Projects	3
Total	4

23. Even if the retirements identified by EPA for 2016 did not occur until 2022, when compliance targets set by the Clean Power Plan become effective, many of the actions identified above would not only still be necessary but would also still need to begin in 2016-2017 in order to minimize the reliability impacts of delivering electric service. Specifically, to accommodate those retirements, Mississippi Power would still have to begin the transmission projects that require five years or longer to complete, and the expenditure to support those projects would be in excess of $4 million in 2016-2017.

Impacts from Fuel Contracts and Inventories

24. Under EPA's compliance solution, across the Southern Company system as a whole, the operating companies will incur costs of approximately $950 million in the 2016-2017 timeframe due to the impact on our fuel contracts and fuel inventories. As referenced by Kim Greene, these include: (1) the incremental cost to reduce coal contract volumes, assuming diverting remaining coal shipments to other coal units whenever possible; (2) liquidated damages associated with transportation contract cancellations; (3) costs associated with other fuel-related impacts, such as incremental costs to reduce other materials' contract volumes, including limestone, gypsum, fuel oil agreements, and railcar leases; (4) costs to cancel firm transportation agreements for natural gas to retired units, assuming no remarketing capability; and (5) the increase in system production cost, which results from forcing coal units to operate in order to consume the retiring

units' coal inventories. Mississippi Power will bear $23 million of these costs as identified below, and once contracts are cancelled, they cannot easily be reinstated. Even if some of these costs could be mitigated under force majeure, substantial impacts would clearly remain.

Costs to Mississippi Power from Fuel Contracts

Fuel Costs	Estimated Cost in 2016-2017 ($2015)
Additional Fuel Related Impacts	$3M
Gas Firm Transportation Cancellations	$20M
Total	**$23M**

Impacts to Local Economies

25. The retirement of the units defined in EPA's compliance solution would have immediate and irreparable impacts on local economies. In Mississippi alone, local communities served by Mississippi Power will lose approximately $15 million in annual property taxes beginning in 2016. These tax dollars are used by local governments to help fund basic services from police and fire protection to sanitation and education.

26. In addition to the dramatic reduction in tax base, the 2016 retirements will result in approximately 95 direct job losses, with more losses occurring as additional units are retired.

Remaining Useful Life

27. The premature retirement of Mississippi Power's units identified in EPA's compliance solution will result in closure of units that otherwise would have been economic to continue operating for many years. Mississippi Power has recently invested substantial capital resources in these units, primarily for compliance with other EPA regulations. The net book value of units identified as retiring in 2016 under EPA's compliance solution is over $250 million as of July

2015. In addition, Mississippi Power has already committed nearly $200 million in investments to come online at those units in the next year.

Conclusion

28. Unless the Final Rule is stayed, EPA's compliance solution shows immediate and irreparable impacts on Mississippi Power, its employees, its customers, and the local communities it serves. These impacts are caused by the retirement of significant generating capacity that EPA's model shows occurring in 2016, even though this capacity would otherwise serve Mississippi's electricity needs for many years. The retirements identified in EPA's compliance solution would negatively affect our customers and the communities that we serve by increasing their cost for electricity, risking reliability, dramatically reducing the tax base, and causing substantial job losses.

29. Direct impacts to Mississippi Power in excess of $30 million in 2016-2017 result from the need to undertake new transmission projects (which could not be completed in 2016) and from the impacts to fuel contracts and inventories.

30. Even if the retirements identified in EPA's compliance solution for 2016 occur in 2022, Mississippi Power would be required to take action and incur approximately $23 million in costs in 2016-2017 to ensure that it can continue to provide safe, reliable, and affordable electricity service.

Respectfully submitted,

R. Allen Reaves, Jr.
Mississippi Power, Senior Production Officer

October 13, 2015

ATTACHMENT S

TO

MOTION OF UTILITY AND ALLIED PETITIONERS FOR STAY OF RULE

Declaration of James J. Jura (Oct. 12, 2015)

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

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION, *et al.* Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, Respondent.	No. ____________

DECLARATION OF JAMES J. JURA OF ASSOCIATED ELECTRIC COOPERATIVE, INC. IN SUPPORT OF MOTION TO STAY

I, James J. Jura, declare:

1. I am CEO and General Manager of Associated Electric Cooperative, Inc. ("Associated"). In that capacity, I am ultimately responsibility for providing Associated's members with an economical and reliable power supply and support services. I have broad latitude authorized by the policies of the Board of Directors to develop and implement strategies and tactics that achieve Board objectives and ensure the long-term success of Associated. I am responsible for directing the generation and transmission of electricity to meet member system demand; informing and involving member owners; ensuring strong financial planning and flexibility; ensuring compliance with all applicable industry state and federal laws

and regulations; identifying and managing the risks of Associated's business; developing and maintaining strategic alliances; and representing Associated on a local, regional and national level.

2. I have worked for Associated for 24 years. Prior to joining Associated, I was employed as Administrator of the Bonneville Power Administration and before that worked for the Office of Management and Budget in Washington, D.C. I began my federal career in 1971 with the Department of Labor's Occupational Safety and Health Administration and prior to this was employed by Boeing Company.

3. I earned a Bachelor of Arts degree and graduated from the University of Washington in 1968, completing a master's degree in Business Administration from Seattle University in 1970. In 1983, I completed the Advanced Management Program at Harvard University's Graduate School of Business.

4. Associated is part of a three-tiered system unified by the common purpose of serving electric cooperative members in rural areas of Missouri, southeast Iowa, and northeast Oklahoma by providing them with clean, affordable and reliable electricity. The top tier of this system comprises 51 electric distribution cooperatives that provide electric service directly to about 875,000 member-consumers, including businesses, farms, and households. Those cooperatives install and maintain power lines, plan for future needs, and work

directly with their communities to encourage economic development, promote energy efficiency, and educate consumers about technology and safety. The second tier is made up of six regional generation and transmission cooperatives (G&Ts) that own and transmit power from Associated to the 51 distribution cooperatives. The six G&Ts operate, build, and maintain the transmission system. Associated, the third tier in this system, was formed in 1961 to provide the G&Ts with a wholesale power supply.

5. Headquartered in Missouri, Associated is member-governed and member-controlled and, as a not-for-profit cooperative, is committed to providing reliable and low-cost wholesale electricity to its six G&T member-owners.

6. On August 3, 2015, the United States Environmental Protection Agency ("EPA") signed the final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units ("111(d) Rule" or the "Rule").

7. As explained more fully in the Declaration of Lisa Johnson, filed on behalf of Seminole Electric Cooperative, the 111(d) Rule requires a drastic reduction in fossil fuel-fired generation, with a 32-percent reduction in carbon dioxide (CO_2) emissions from 2005 levels required by 2030. The 111(d) Rule achieves those reductions through uniform CO_2 emission performance rates EPA has imposed on two subcategories of existing power plants (coal- and natural gas-

fired units) and state-wide rate- or mass-based emissions goals that are formulated from the subcategory performance rates. States are required to formulate state plans for compliance and submit those plans to EPA for approval. Although states must plan for compliance, affected units like those owned and operated by Associated are ultimately responsible for compliance with the interim and final goals established in the Rule.

8. By EPA's own admission, existing units cannot meet the new performance rates though any technological or operational changes at the unit without curtailing their generation or shuttering their plants, shifting generation to lower-emitting sources, and/or purchasing credits or allowances under a potential future emissions trading program.

9. The 111(d) Rule could force Associated to commit to curtailing coal or even shuttering a significant percentage of its coal-fired base-load and intermediate electricity generating facilities, including New Madrid Unit 1 ("NM1") alone, or Thomas Hill Unit 1 ("TH1") either alone or in combination with Thomas Hill Unit 2 ("TH2"), by 2022. To achieve compliance by 2022, Associated will need to make planning and resource allocation decisions long before any state plans implementing the 111(d) Rule are submitted, well before EPA's proposed Federal Implementation Plan and model state trading rules are finalized, and almost certainly before this litigation is resolved. Because

Associated must make these business decisions almost immediately to prepare to comply with the 111(d) Rule, the Rule will have imminent and irreparable economic consequences for Associated if it is not enjoined until this Court has had a full opportunity for review.

Introduction to Associated and its Generating Units

10. Like most electric cooperatives, Associated serves rural areas that would not be profitable for traditional investor-owned utilities and that such utilities typically therefore decline to serve. As explained more fully in the Declaration of Kirk Johnson, filed on behalf of the National Rural Electric Cooperative Association ("NRECA"), the principal purpose of rural electric cooperatives like Associated (a member of NRECA) is to provide affordable electricity to underserved rural and largely lower-income populations. To that end, Associated provides essential electric service in primarily rural and low-income areas of Missouri, southeast Iowa and northeast Oklahoma.

11. The average income of Associated's residential member-consumers is between $25,000 and $50,000 a year. Sixteen percent of Associated's customers make less than $25,000 a year. An estimated 80 percent are over age 45, and 35 percent are 65 and older.

12. Being a not-for-profit cooperative means that Associated's member-consumers directly bear the costs of Associated's energy infrastructure. Any

increased costs must be reflected in increased electricity rates. If Associated is required to build additional generation or purchase otherwise unnecessary power to comply with EPA's new carbon dioxide (CO_2) emissions limits for existing sources, discussed below, this will directly result in higher electricity rates to Associated's lower-income customers.

13. Like other rural electric cooperatives, Associated's members have fewer customers per mile of line than investor-owned utilities; nationally, cooperatives have only 19-20 percent of the customer density of investor-owned utilities. For example, the second largest investor-owned utility in Missouri has 29.62 customers per mile of transmission and distribution line, while Associated's member cooperatives have an average of only 6.04 customers per mile of line, making its customer density 80 percent lower than that of the investor-owned utility. As a result, Associated has far fewer customers to share the costs of its infrastructure and capital investments.

14. Seventy-nine percent of Associated' s electricity was generated from coal-fired resources in 2014, including the coal-fired New Madrid Power Plant in Southeast Missouri, which has 1,200 MW capacity, and the Thomas Hill Energy Center in north-central Missouri, which has three operating units and a 1,153 MW capacity. Associated owns the Thomas Hill plant. It operates the New Madrid facility, which is owned by the City of New Madrid.

15. The unit at New Madrid (NM1) and the two units at Thomas Hill (TH1 and TH2) are base-load generation resources rated at 600 MW, 180 MW, and 303 MW, respectively. Combined, the three units have operated at an average capacity factor of 81.7 percent over the last three years. In other words, the three units are very heavily utilized. In fact, in 2014, NM1, TH1 and TH2 generated approximately 31.4 percent of the total energy Associated provided to its Members.

Summary of the 111(d) Rule

16. As stated above, the 111(d) Rule assigns a uniform performance rate for each existing coal-fired and natural gas-fired electric generating unit to reduce CO_2 from existing power plants, measured in terms of pounds of CO_2 emitted for every net megawatt hour, or lbs CO_2/MWh-net. For existing coal-fired units like New Madrid and Thomas Hill, the performance rate is 1,305 lbs CO_2/MWh-net. For gas-fired units, the performance rate is 771 lbs CO_2/MWh-net. Those performance rates were used by EPA to calculate state-wide emission goals, as explained in the next paragraph, and individual units must comply with these rates or their equivalents by 2030.

17. The Rule sets forth statewide rate- and mass-based emission goals for each state calculated from the weighted aggregate of emission performance rates applicable to the state's existing coal-, gas- and oil-fired power plants in the

baseline year 2012. Missouri's final rate-based CO_2 emission performance standard is 1,272 lbs CO_2 /MWh and its mass-based goal is 55,462,884 short tons of CO_2.

18. Although the *final* state goals are not effective until 2030, the 111(d) Rule establishes a “glide path” with increasingly stringent interim emission reduction requirements and average interim performance rates and goals for the 2022 to 2029 compliance period, in addition to the 2030 final performance rates and goals. States and individual units must meet both the interim and final requirements or face corrective EPA action.

19. For example, to achieve its final rate-based CO_2 emission performance goal of 1,272 lbs CO_2/MWh by 2030, Missouri must achieve an average interim emission rate of 1,490 lbs CO_2/MWh over the eight years from 2022 to 2029. Missouri’s interim step goals for the glide path are: 1,621 lbs CO_2/MWh (Step 1, 2022-2024), 1,457lbs CO_2/MWh (Step 2, 2025-2027), and 1,342 lbs CO_2/MWh (Step 3, 2028-2029). The mass-based interim goal for Missouri is 62,569,433 tons CO_2/yr. The step goals are 67,312,915 tons CO_2/yr. (Step 1, 2022-2024), 61,158,279 tons CO_2/yr. (Step 2, 2025-2027) and 57,570,942 tons CO_2/yr. (Step 3, 2028-2029). The State also has discretion in choosing its own interim path to compliance if it has adopted a mass-based performance goal and as long as the interim and final goals are met.

20. States may directly impose source-specific emission standards or requirements, or they may adopt other measures that achieve equivalent CO_2 emission reductions from the same group of existing electric generating units under an "emissions standards" plan or "state measures plan." *See* Lisa Johnson Decl., ¶ 19-20. Regardless of which compliance approach states choose, emission reductions from affected electric generating units like NM1, TH1 and TH2 individually or in the aggregate must achieve the equivalent of the EPA-specified CO_2 emission performance rates by 2030, expressed via the state-specific rate- or mass-based goals.

21. States must submit at least an initial state plan to EPA by September 6, 2016, less than 12 months from now. The 111(d) Rule allows states to seek an extension to September 6, 2018, to submit a final plan, provided they meet certain conditions. EPA has pledged to review and approve state plans within a year of their submission. The State of Missouri thus has until September 6, 2018, to submit a final plan so long as it submits an initial plan for compliance by September 6, 2016, and seeks an extension from EPA. It will not be clear what compliance methods will be ultimately adopted by the State – including whether a trading program will be established, the term of any such program, or whether that program will be acceptable to EPA – until the plan is finalized and approved sometime in late 2018 or 2019. The State also has the discretion to choose not to

adopt a trading program in favor of other methods of compliance. In short, there is likely to be no certainty about the shape of Missouri's plan, whether trading will be available under it and, if so, on what terms trading will be available, for at least another four years.

The Rule's Effect on Associated

22. None of Associated's coal-fired generating resources can meet the final 111(d) Rule's performance rate for existing coal-fired plants. Under the 111(d) Rule, Associated's coal-fired units (NM1, TH1 and TH2) each would be permitted to emit no more than 1,305 lbs CO_2/MWh-net annually by 2030. The five-year (2010-2014) average emission rate (net) for each unit, respectively, is 2,012 lbs CO_2/MWh (NM1), 2,486 lbs CO_2/MWh (TH1) and 2,204 lbs CO_2/MWh (TH2), each of which is well above the unit-specific performance rate mandated by the final Rule.

23. To comply with the 111(d) Rule, Associated is evaluating shutting down either (a) New Madrid Unit 1 (NM1) or (b) Thomas Hill Unit 1 (TH1) and/or Thomas Hill Unit 2 (TH2). This is because the 111(d) Rule's emission limits simply cannot be met by any available emission control technology or operational measures at the units short of curtailing operations or shutting down the unit(s) completely.

24. Associated can achieve the coal-fired and gas-fired emission rates in only three possible ways: (i) curtailment of operations and replacement of the lost generation from NM1, TH1, and TH2 with lower-emitting generation; (ii) closure of NM1, TH1, and TH2 entirely and replacement of the units with new natural gas-fired units; or (iii) purchase of emission reduction credits or allowances through a trading system that *might* be established pursuant to the 111(d) Rule many years hence. None of these options is feasible given the current regulatory uncertainty associated with the 111(d) Rule, as explained further in the remaining paragraphs.

25. The first two options explained in the previous paragraph (curtailment and replacement or closure and replacement) will require the premature closure of NM1 or TH1 and/or TH2, at extraordinary cost to Associated and its Members. To replace that lost capacity (375 MW), Associated must choose to construct new natural gas generation facilities (since its current natural gas capacity is only 44 percent of its generation and not sufficient to replace the baseload generation that would be lost with premature closure of one or more coal-fired units) or to contract for purchased power supply from third parties and/or contract for natural gas to be used at purchase power resource facilities. Under any option, Associated must make this irrevocable decision *soon* to be in service in 2022 and beyond – and before a final State Plan is chosen, in any event.

26. Of those options, Associated would likely construct some combination of natural gas combined cycle ("NGCC") and renewables. If Associated were to meet the 375 MW of new generation through construction of a natural gas facility alone, a reasonable assumption is that the capital cost of bringing a unit online by 2022 would be $550 million ($492 million for the generation and $59 million for the pipeline), in addition to capital costs for transmission and water for the plant. The transmission cannot be planned and priced until Associated has settled on a location, which is being evaluated now.

27. The construction costs associated with building new renewable generation (including any backup generation to up-balance renewables due to a variable capacity factor) are currently less certain, but renewables can be expected to generate power that is significantly more expensive on a dollar-per-MWH basis than natural gas – resulting, again, in higher costs passed on to rural ratepayers who cannot afford such increases.

28. To replace NM1 or TH1 and/or TH2 by 2022, Associated will have to choose and evaluate potential sites and apply for the requisite environmental and local permits *by 2017* at a cost of approximately $2 million.

29. Because Associated will be carrying approximately $550 million in outstanding debt associated with the prematurely-retired unit(s) when it obtains that additional financing, its credit rating also may be negatively affected. Credit

rating downgrades extend across all aspects of a utility, negatively affecting contracts, financing, and rates. Associated's rates would be forced to increase to cover the costs of new gas generation while continuing to pay for the sunk costs and outstanding debt associated with the shuttered unit(s).

30. Associated must also make decisions about whether to make planned capital and environmental investments in its existing coal-fired units before the state plans are finalized in September 2018. The capital and environmental plan for NM1 currently includes $26,500,000 slated for environmental projects and $35,673,337 in plant efficiency projects. For TH1, there are $2,005,505 in planned environmental projects and $11,999,834 in planned plant efficiency projects. For TH2, there are $2,423,212 in environmental and $16,828,321 in capital efficiency projects planned. If one or more unit(s) will be forced to retire under the final 111(d) Rule, Associated would forgo spending anywhere from $14,005,339 to $62,173,337 of those costs, which were elective expenditures designed to increase efficiency and protect the environment but which were not required by any applicable regulatory rules or standards. The uncertainty created by the 111(d) Rule creates another decision that Associated must make with incomplete information: Associated must choose *now* whether to spend the additional money on the improvements and risk losing the investments if the

facility is retired, or choose not to spend the money and forgo the environmental benefits and efficiency gains that could be achieved.

31. The third option for compliance described above – purchase of emission reduction credits or allowances under a 111(d) Rule-compliant trading program – will not even be available to Associated *unless* Missouri adopts such a system. Associated will not know with any certainty whether such trading will be available until late 2018 or in 2019, because the state plan requires development and EPA approval, both of which are time-consuming. In order to bring the new generation resources noted above online in 2022 and beyond, Associated must make decisions years before 2022. It does not have the luxury of waiting to see whether Missouri adopts a trading program or whether that program will provide sufficient credits or allowances, at economic prices, to allow the continued operation of the coal-fired unit(s).

32. Associated is a cooperative that cannot absorb the enormous costs of constructing a lower-emitting generating facility or contracting for lower-emitting generating capacity without passing those costs along to its customers. Premature closure of the unit(s), and the inability of Associated to replace that lost generating capacity at a cost that would be affordable to Associated’s customers will have significant detrimental impacts on Associated and its Members: (1) half of the employees at New Madrid station (currently 200) or Thomas Hill station (currently

250) would lose jobs if these units close, (2) Associated's rates will increase and may no longer be competitive with those of investor-owned utilities in the state, driving much needed economic development out of Missouri's rural areas; and (3) the entire objective of the federally-crafted rural cooperative structure will be undermined.

33. Unless the 111(d) Rule is stayed pending judicial review, Associated must take the immediate and irreversible steps described above, causing Associated, its Members, and its customers to suffer irreparable harm. If the 111(d) Rule is later invalidated, Associated will have already committed to premature closings and/or significant curtailment of its operating power generation facilities and the resulting significant expenditures on natural gas generation facilities and new gas pipeline construction and/or purchase contracts that will no longer be needed.

Pursuant to 28 U.S.C. § 1746, I declare under the penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Executed: This 12th day of October, 2015.

By: James J. Jura

James J. Jura
CEO & General Manager
Associated Electric Cooperative, Inc.