Entity/Other	***Reliability***
MISO	14 GW of coal capacity could be at risk for retirement. Many stakeholders have requested that MISO conduct a reliability analysis of the EPA's proposal. In response, in Phase III MISO is currently working to perform reliability assessments with respect to the impacts of the 14 GW of additional retirements identified in this first phase. Additionally MISO fully expects to perform reliability and transmission modeling in future phases as stakeholders target the scenarios most worthy of additional study. *[NOTE: This is from MISO South Region's October 2, 2014 comments to the Louisiana PSC. Phase III is the next modeling phase for MISO, as Phase I and Phase II are completed and have modeled compliance costs]* *** At an October 23, 2014 Board of Directors meeting, MISO announced it had and was continuing to revisit the 14 GW retirement risk figure and that it may be significantly higher: "In six years, there could be a power shortfall of 25 GW, MISO System Planning Committee Chair J. Michael Evans warned. It would take about 70 new natural gas-fired combined-cycle plants to fill that gap, Evans said. "That might suck up well in excess of the available ability of industry to produce turbines, especially when you consider that China and Japan and other people are going to want a few of them too," he said. MISO will report these concerns to the EPA in detail in the comments it will make publicly available next month. … MISO's forecast of 14 GW of retirements is not necessarily final. The grid operator continues to examine the modeling behind that study, MISO President and CEO John Bear said in the meeting. "The initial results were a starting point for MISO's study of the proposed rule," MISO spokesman Andy Schonert said in an email. "We are continuing our work with stakeholders to develop more granular studies about the potential impacts across the footprint, all with the goal of providing our membership additional information and background." *[NOTE: This is from an SNL article and will be updated when MISO issues more formal results]*
SPP	[Reliability Assessment – October 8, 2014] Transmission System Impact Analysis [Part 1 and Part 2] Part 1 of the TSIA was performed using a current 10-year-out summer peak model modified to reflect EPA's projected retirements in the SPP region and surrounding areas. Reactive power limits on remaining generators were increased as necessary to enable a minimally solvable power flow model under system intact conditions and to account for reactive power shortfalls within SPP. Part 2 of the TSIA was performed using an updated 10-year-out summer peak model modified to reflect EPA's projected retirements in the SPP region and surrounding areas. Additionally, new gas-fired and wind generators (see Figure 2) were added within SPP's region and dispatched to offset the majority of the EPA retirements. The generators added to the model were placed in locations based on resource plans developed to support SPP's 10-year transmission planning evaluation. New gas generators, including combined cycle (CC) and combustion turbine (CT), were dispatched at approximately 5,600 MW and new wind generators were dispatched at approximately 300 MW in SPP's model. Wind generation levels at existing plants in SPP were increased by approximately 3000 MW to serve load in SPP and support 2000 MW of transfers from SPP to adjacent areas in Arkansas and Louisiana that would be capacity deficient based on the EPA projected retirements. Additionally, wind resources in MISO were increased to provide 2000 MW of transfers from MISO to these same deficient regions in Arkansas and Louisiana. Both parts of the TSIA identified significant reliability issues. The issues were not mitigated, but actually increased, despite the optimal generation expansion and conservative assumptions used in Part 2 to address EPA retirements. [TSIA Part 1]: ***As a result of the assumed EPA retirements with no resource additions, the SPP network was so severely stressed by large reactive deficiencies that the software used in the analysis was unable to produce meaningful results, which is generally indicative of voltage collapse and blackout conditions.*** In order to enable analytical results, SPP modeled increased reactive limits at remaining generators on the system and was eventually able to achieve analytical results by adding approximately 5,200 MVAR of reactive production to the model during system intact conditions. Because of the arbitrary nature of artificially increasing reactive limits of generators, reliability indicators such as equipment loadings and voltage levels are not accurate and are not presented in this Report. However, this analysis indicates approximately 5,200 MVAR of reactive deficiencies in the SPP footprint during system intact conditions resulting from the modeled EPA generator retirements. Figure 3 shows the reactive power deficiencies within SPP identified by this analysis. The most notable deficiencies were found in Texas and eastern Oklahoma. (emphasis added)

	[TSIA Part 2]: Part 2 of the TSIA utilized the latest optimal generation resource plans available to SPP as well as existing wind resources to mitigate generation shortfalls within SPP. Existing wind generation in SPP and the northern part of MISO were increased to serve shortfalls in the southern part of MISO. An N-1 assessment revealed 38 overloaded elements. ***These overloaded elements were identified in the portions of six states – Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas – that operate within the SPP region. Portions of the system in the Texas panhandle, western Kansas, and northern Arkansas were so severely overloaded that cascading outages and voltage collapse would occur.*** (emphasis added) [Resource Adequacy Analysis]: The Assessment evaluated the impacts of the projected EGU retirements on SPP's reserve margin. SPP has a minimum reserve margin requirement of 13.6% that every SPP member with load serving responsibilities must plan to meet with appropriate generation capacity. In evaluating the impacts of the projected EGU retirements on SPP's reserve margin, SPP utilized current load forecasts, currently planned generator retirements and additions, as well as the retirements projected by the EPA. The Assessment showed that by 2020, SPP's reserve margin would fall to 4.7%, which is 8.9% below our minimum reserve margin requirement. Out of SPP's fourteen load-serving members impacted by the EPA's projected retirements, nine would be deficient in 2020. Furthermore, SPP found that its anticipated reserve margin would fall to -4.0% in 2024, increasing the number of deficient load serving entities to ten. These anticipated reserve margins represent a generation capacity deficiency of approximately 4.6 GW in 2020 and 10.1 GW in 2024. [Conclusion]: The findings in this Assessment make it very clear that new generation and transmission expansion will be necessary to maintain reliability during summer peak conditions if EPA's projected generator retirements occur. Even the scenario that assumes optimal resource expansion using new natural gas fired resources could be problematic during extreme winter load conditions with gas supply and delivery challenges …. ***Unprecedented coordination and cooperation beyond regional planning efforts will be necessary, but may not be timely given significant challenges with interregional planning and necessary system expansion. In addition, broader system assessments of the bulk power system, and natural gas pipeline and storage systems based on environmental constraints will be required.*** *** [EPA Comments – October 9, 2014] [Addressing TSIA Part 1 and Part 2]: The SPP region will experience numerous thermal overloads and low voltage occurrences under both scenarios studied. Results of the first part of the transmission system impact evaluation indicate that if the assumed EGU retirements were to occur absent requisite transmission and generation infrastructure improvements, the power grid would suffer extreme reactive deficiencies (see Figure 3) that would expose it to widespread reliability risks resulting in significant loss of load and violations of NERC reliability standards …. [Addressing limited scope of reliability analysis]: Based on SPP's reliability impact assessment, it is clear that the proposed CPP will impede reliable operation of the electric transmission grid in the SPP region, resulting in violations of NERC's mandatory reliability standards and exposing the power grid to significant interruption or loss of load. SPP has only been able to perform an initial reliability evaluation of steady-state system response during a "normal" future summer peak condition. SPP has not evaluated the impact of the proposed EGU retirements during other potentially critical scenarios, such as drought and polar vortex conditions or times of limited wind resource availability, which have been experienced numerous times within SPP's region in recent history. [Addressing reliability safety valve concept from ISO/RTO Council]: In addition to more time being needed to develop plans for and construction of necessary infrastructure, a "reliability safety valve", as suggested by the ISO/RTO Council prior to release of the proposed CPP, should be incorporated into the final rule. Such an approach would require that state plans include a process to evaluate electric system reliability issues resulting from implementation of the state plan and require mitigation when needed. [Recommendations to EPA]: SPP is providing four recommendations: 1) a series of technical conferences jointly sponsored by the EPA and FERC; 2) completion of a detailed, comprehensive and independent analysis of the impacts the proposed CPP will have on the reliability of the nation's bulk electric system; 3) extension of the proposed schedule for compliance in order for the necessary electric and gas infrastructure to be identified and constructed; and 4) adoption of a "reliability safety valve".
NERC	By October 7, 2014, NERC planned to release a document with six to eight reliability concerns that EPA needs to address. *[NOTE: This is according to comments made by CEO Gerry Cauley before the North Dakota PSC on September 10, 2014, prior to the comment deadline extension]*.
ERCOT	ERCOT is currently analyzing a set of environmental regulations (Clean Power Plan, MATS, Cross-State Air Pollution Rule, Regional Haze, Section 316(b) of the Clean Water Act, and proposed revisions to the Ash Disposal rules) and their potential impact on the grid. The focus of the ERCOT study is on grid reliability, but ERCOT's real concern is compliance deadlines and the possibility that compliance may be achievable, but at significant cost to the ERCOT system. ERCOT's study will be complete in late November or early December and the results of that study will be incorporated into the PUC's comments to EPA.

	[NOTE: This is paraphrased from live testimony from Warren Lasher (Director of System Planning, ERCOT) during the Texas House of Representatives Committee on Environmental Regulation's two-day hearing regarding the proposed rule on September 29-30, 2014] *** [October 8, 2014 outage illustrates reliability issues under current conditions – ERCOT press release below] 7 p.m., Oct. 8, 2014 – The Electric Reliability Council of Texas (ERCOT) at 6:29 p.m. instructed transmission and distribution service providers to restore electric service following rotating outages in the Lower Rio Grande Valley. While most affected consumers will be returned to service immediately, some providers indicate it could take about an hour to restore service to all affected consumers. Earlier this evening, unplanned power plant outages resulted in electric transmission issues in the Valley, which required action by the grid operator to protect the system in that area. At 4:47 p.m., ERCOT instructed the transmission and distribution providers to reduce system demand by 200 MW to protect the Valley region from the risk of an uncontrolled blackout situation. Additional power also was imported from the power grid in Mexico to help address transmission system issues in the area, and ERCOT is working with the affected generation owners to return their units to service. "We appreciate the patience and help from Valley residents during this situation," said Ken McIntyre, ERCOT vice president, Grid Planning and Operations. "We have been working with transmission providers on projects to improve future electric reliability in the Valley region."
PJM	The Organization of PJM States, Inc. (OPSI) requested PJM Interconnection staff to perform analyses of the potential impacts of U.S. EPA's proposed 111(d) Carbon rule. OPSI's request outlined base case, regional compliance case, regional compliance case scenarios and state-by-state compliance case modeling assumptions. PJM has committed to performing the requested analyses of years 2020, 2025, and 2029 and will augment them with additional sensitivity scenarios focused on generation availability and energy efficiency assumptions. The analyses results will include (by transmission owner zone, state and RTO region): carbon price, carbon emissions rate, Locational Marginal Prices, energy market load payments, percentage of generation by fuel type, and generator net energy market revenue (net of going forward fixed avoidable capital costs). The scope of the initial analyses does not include a transmission planning reliability analysis. PJM will not be identifying NERC transmission planning criteria violations or determining the transmission solutions to address any criteria violations. PJM's modeling will be an energy market analysis. However, PJM intends to use the results of this initial energy market analysis to inform future "at-risk" scenario studies to be performed as part of the PJM Regional Transmission Expansion Planning process. PJM is targeting late October to complete and publish initial results from this analysis and will offer sessions with the states and with stakeholders to review the initial results. PJM will comply with its Operating Agreement provisions pertaining to confidential data.
WECC	An analysis of the Anticipated Planning Reserve margins calculated in the NERC 2014 Long-Term Reliability Assessment shows that in 2020, the beginning of the enforcement period, all four of the WECC subregions have capacity in excess of the 15 percent target. However with the loss of approximately 400 MW (or .53 percent) of capacity in the US portion of the NW subregion, 700 MW (2.97 percent) in the Southwest subregion, 3,500 MW (35 percent) in the Rocky Mountain subregion, or 200 MW (.32 percent) in the US portion of the California/Mexico subregion, the calculated Planning Reserve margin for those subregions could drop below the 15 percent target. … The study results suggest that removing the specified about of coal generation, given the assumptions, would have minimal impact on system frequency response. The minimal change in frequency response is not surprising given that 7,000 MW of incremental retirements represents only about 3.5 percent of the total generation (198,000 MW) in the heavy summer case. Preliminary analysis suggest that the effects would also be minimal in a typical lightly loaded case as the total generation typically being represented is closer to 100,000 MW and still would only result in 7 percent of the generation being displaced …. Interconnection-wide frequency response was not significantly impacted by the specific scenarios analyzed. That is not to say that there are no other reliability issues that should be examined.

Florida PSC Commissioner Eduardo C. Balbis	Reliability is a very real and very significant concern due to Florida's limited interstate transmission capability. Furthermore, Florida's annual cooling degree days is the highest in the continental U.S. Due to these factors, Florida must rely on intrastate generating facilities capable of continuously meeting high levels of demand reliably. Thus, Florida relies heavily on a robust and dispatchable generating fleet. Many of the low carbon/zero carbon technologies the EPA uses to justify the 10 percent Block 3 calculation are intermittent, non-dispatchable, non-base load technologies. For example, in 2013, PV's capacity factor ranged from 13 to 22 pecent *(sic)*. The low capacity factors of many low carbon/zero carbon technologies (excepting nuclear) combined with Florida's need for dispatchable generation means Florida would need to build additional natural gas-fired facilities and related infrastructure for use as stand-by units for reliability purposes. The EPA errs in failing to account for these additional capital expenditures needed to ensure system reliability.
Montana PSC Commissioner Travis Kavulla	Much of the conversation around the EPA's proposed rule has focused on the question of reliability. I will not speculate on the rule's reliability impacts, for the simple reason that no reliability analysis of the EPA's proposed "Best System of Emission Reduction" (BSER) has been conducted for the Western Interconnection, which encompasses 11 states, 2 Canadian provinces, and Mexico's Baja California. Transmission planners at WECC, which is responsible for adopting and enforcing reliability standards for this large slice of the continent, have told state regulators that they cannot accomplish such an analysis by the October comment deadline. Other than WECC, few if any other organizations are in a position to conduct such an analysis. In any case, none have. Many, including the EPA itself, have said that whatever else the proposed regulation accomplishes, it must keep the electric grid operating reliably. I agree. Absent a transmission modeling study that concludes that the BSER's Building Block approach would result in a system as reliable as the one we have today, it is inappropriate to claim that the EPA's BSER is adequately demonstrated. EPA has modeled the outcome of the BSER assumptions using its Integrated Planning Model (IPM). It is important to understand what this model is and is not. The IPM does not and is not intended to model the operations of the transmission grid. Instead, the model focuses on whether in a particular region there are an adequate amount of electric supply resources to meet consumer demand. While this question of resource adequacy is essential to reliability, it is equally necessary to understand whether the resources that exist in a particular region can be delivered to the consumer location of demand. Many of the most critical resources that serve large pockets of consumer demand are located in transmission-congested areas. If this transmission congestion is not incorporated into a model—and, again, IPM does not—then that model cannot reach meaningful conclusions about system reliability. In other words, the way IPM has drawn the regions in its hub-and-spoke representation of the grid do not capture the significant complexity of grid operations within the given region. Additionally, IPM uses an old-world definition of regions that does not accurately represent the present realities of how the transmission grid has been divided into Regional Transmission Organizations (RTOs). Even assuming that the BSER is otherwise a feasible metric for accomplishing the EPA's goal of reducing carbon dioxide emissions, it must be subjected to transmission modeling.
Texas PUC Chair Donna Nelson	According to EPA, more than 40 coal and gas plants will need to retire in Texas. The proposed rule mandates a 52% reduction in coal generation. How will that effect reliability? Texas is in three transmission organizations. It is extremely difficult to try and figure out how to coordinate compliance with this rule. In the Southwest Power Pool's preliminary analysis, its algorithm could not produce results because of reactive deficiencies. And those deficiencies were the worst in Texas, Oklahoma, and Kansas. That means there will be significant loss of load or rolling outages. When SPP measured that impact on generation, its reserve margin would drop to 4.7% by 2020, and by 2024 it would drop to -4%. The current reserve margin in SPP is 13.6%. *[NOTE: This is paraphrased from live remarks during the Texas House of Representatives Committee on Environmental Regulation's two-day hearing regarding the proposed rule on September 29-30, 2014]*
Texas PUC Commissioner Ken Anderson	In determining the BSER for Block 3, EPA uses a capacity factor for Texas wind of between 39% and 41%.6 For reliability purposes, ERCOT assigns wind an 8.7% wind capacity factor which is the estimated availability of wind during summer peak. ERCOT is late in the process of recalculating the effective load-carrying capability (ELCC) of wind and is expected late next month to assign West Texas wind an ELCC of 14.2% and coastal wind and ELCC of 32.9%. Both figures are still substantially below the capacity factor the EPA assigns to Texas wind energy. *[NOTE: The ERCOT Board of Directors is scheduled to discuss and vote on the wind capacity factor assignments above on October 13, 2014]*