Short Summary
Testimony of Allen Short
General Manager, Modesto Irrigation District (MID) on behalf of
MID, M-S-R Public Power Agency, and the Southern California Public Power Authority
June 6, 2012

M-S-R Public Power Agency (M-S-R) and Southern California Public Power Authority (SCPPA) are minority owners in the San Juan Generating Station (SJGS), a four-unit 1,680 MW coal-fired power plant in Farmington, New Mexico, which is in EPA Region 6. M-S-R and SCPPA member agencies receive a significant amount of electric power from the SJGS

M-S-R and SCPPA support New Mexico's State Implementation Plan (SIP) to implement the Clean Air Act's regional haze requirements at the SJGS. The Act's regional haze provisions are intended to gradually improve visibility in national parks and wilderness areas. The New Mexico SIP would reduce haze-causing NOx emissions from the SJGS by 20% through the installation of Best Available Retrofit Technology (BART) over a five-year period at an estimated cost of $77 million.

EPA has rejected the State's approach, issuing a Final Rule in Aug. 2011, that set a regional haze standard for SJGS that is far more stringent than standards imposed elsewhere. EPA's federal implementation plan (FIP) requires the installation of emissions control technology that would cost $750-805 million, based on bids from experienced engineering firms competing to do the work. These real-world estimates are more than twice EPA's estimate of $345 million.

Although EPA's plan would cost 10 times more than the state's plan, it would remove only slightly more haze -- and the improvement would be *virtually imperceptible to the human eye.*

EPA's regional haze FIP for SJGS could affect grid reliability. Environmental groups have asked the court to require that the five-year FIP be put on a three-schedule. This would necessitate shutting down some or all of the generating units at SJGS for two years while emissions controls are installed. A study commissioned by M-S-R concluded that taking SJGS off-line would cause overloads and possible instability on portions of the transmission grid in the Southwest.

SJGS owners have challenged EPA's regional haze FIP in court and have asked EPA to stay enforcement its FIP while the court considers the matter. Recently, New Mexico Gov. Susana Martinez (R) also asked EPA to stay its regional haze order to allow the State, EPA and Public Service of New Mexico (PNM), SJGS's operator, to work toward a compromise plan. We support Gov. Martinez's proposal.

Separately, the Sierra Club and the Natural Resources Defense Council (NRDC) have petitioned the California Energy Commission (CEC) to initiate a rulemaking that would bar SJGS's owners in California from paying their share of regional haze compliance costs for the plant. The environmental groups allege that such investments violate California's greenhouse gas (GHG) emissions law, SB 1368, which prohibits investments that would extend the life of existing coal-fired power plants. The California owners of SJGS disagree with this interpretation of the GHG law.

The California public agencies that have ownership interests in SJGS are willing to do their share for clearer air with cost-effective improvements to bring the plant into compliance with Clean Air Act standards. That is why we support the New Mexico SIP. But our ratepayers should not be required to pay for extremely costly mandates that produce only marginal benefits as compared to far less expensive but similarly effective alternatives.

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Testimony of
Allen Short, General Manager, Modesto Irrigation District
On behalf of
The Modesto Irrigation District,
M-S-R Public Power Agency
And the Southern California Public Power Authority

Before the
Committee on Energy and Commerce,
Subcommittee on Energy and Power
United States House of Representatives

EPA Enforcement Priorities and Practices

Washington, D.C.
June 6, 2012

Chairman Whitfield, Ranking Member Rush and Members of the Subcommittee on Energy and Power:

Good morning. My name is Allen Short and I am the General Manager of the Modesto Irrigation District (MID) in California's Central Valley. Thank you for the opportunity to speak with you today about the potential impacts of the Environmental Protection Agency's approach to enforcement of the Clean Air Act's Regional Haze rule at the San Juan Generating Station, a four-unit 1,680 MW coal-fired power plant near Farmington, New Mexico, which is in EPA Region 6. I am here because the San Juan Generating Station is a significant source of electric power for hundreds of thousands of homes and businesses in Northern, Central and Southern California, as well as in New Mexico and Utah.

My purpose in speaking to you today is to bring to your attention our concerns about EPA's regional haze *federal implementation plan* (FIP) for the San Juan Generating Station, which was finalized last year. The EPA FIP costs 10 times more than a similarly effective *state implementation plan* (SIP) proposed by the State of New Mexico. EPA rejected that portion of New Mexico's plan dealing with the San Juan Generating Station, and instead EPA has mandated emissions controls that will cost hundreds of millions of dollars but produce only marginal haze improvements as compared to the State plan.

MID is a local publically owned utility that provides irrigation service to nearly 60,000 acres and electric service to approximately 113,000 accounts. Annual peak electric demand is more than 600 MW, which MID meets with a mix of hydroelectric, wind, solar and thermal generation. MID is in partnership with the City of Santa Clara and the City of Redding in the M-S-R Public Power Agency (M-S-R), which has made investments in renewable and thermal generation resources to provide electricity to 210,000 residential and commercial customers in three counties of Central and Northern California. Among those resources is the San Juan Generation Station. M-S-R owns a 28.8-percent share of San Juan

Generating Station Unit 4, which provides 150 MW annually to M-S-R, representing nearly 25 percent of MID's total supply and 15 percent of Santa Clara's and 21 percent of Redding's municipal power supplies (based on calendar year 2010 retail sales).

The San Juan Generating Station is also an important source of electric power for public utilities that are participants in the Southern California Public Power Authority (SCPPA), whose members are 11 municipalities and one irrigation district that deliver electricity to approximately 4.8 million people over an area of 7,000 square miles. Five SCPPA members own a 41.8 percent of San Juan Unit 3, and the City of Anaheim, also a SCPPA member, owns a 10 percent share of San Juan Unit 4.

The principal owner of the San Juan Generating Station is the Public Service Company of New Mexico (PNM), an investor-owned utility that also operates the plant. My testimony today is on behalf of the public utilities that are San Juan's minority owners in California: the Modesto Irrigation District, M-S-R Public Power Agency and the Southern California Public Power Authority.

Summary

The Clean Air Act has charged EPA and the states with improving the air quality in national parks and wilderness areas. In 1999, EPA issued the Regional Haze Rule that requires the states, in coordination with EPA and other federal agencies, to develop and implement air quality protection plans to address regional haze by improving visibility at 156 national parks and wilderness areas. Specifically, states are required to establish goals for improving visibility and develop long-term strategies over a 60-year period to reduce emissions of air pollutants that cause visibility impairment.

In 2011 the State of New Mexico proposed a regional haze SIP that would reduce haze-causing nitrogen oxide (NOx) emissions from the San Juan Generating Station by 20 percent through the installation of Best Available Retrofit Technology (BART) over a five-year period at an estimated cost of $77 million. However, EPA issued a final rule in August, 2011, that set a regional haze standard for San Juan that is far more stringent than standards that have been imposed elsewhere. The rule established a regional haze FIP for the San Juan Generating Station that requires the installation of emissions control technology that would cost $750 million to $805 million, based on bids from two reputable engineering firms specializing in this technology. Although EPA's plan would cost 10 times more than the state's plan, it would remove only slightly more haze -- and the improvement would be *virtually imperceptible to the human eye*[1].

Though it rejected provisions of the New Mexico SIP addressing regional haze controls at the San Juan Generating Station, EPA approved the rest of the State's plan on May 31, 2012.

The San Juan Generating Station's owners have challenged EPA's regional haze FIP in federal court. In addition, the owners and the State of New Mexico have asked EPA for a stay of enforcement of the FIP while the matter is being considered by the courts. Without a stay, the owners have no choice but to begin carrying out the EPA order immediately, incurring tens of millions of dollars in engineering and construction costs for work that the courts may ultimately determine isn't necessary.

1 Visibility improvements are measured by an index scaled in deciviews (dv) which are analogous to the decibel scale for sound. A one dv change is approximately a 10% change in the extinction coefficient. The improvement in visibility effected by the State plan is about 1 dv and by the EPA plan is about 1 ½ dv at Mesa Verde National Park. If, for example, median summer visibility in region is 50 miles, the State plan would improve visibility to 72 miles while the EPA plan would improve visibility to 78 miles. According to material published by Colorado State University this 6 mile difference in visibility would be imperceptible to 90% of the populace. (Based on Figures 2 & 3 retrieved April 30, 2012 from: http://vista.cira.colostate.edu/improve/publications/NewsLetters/apr_93.pdf)

The Modesto Irrigation District and the other members of M-S-R and SCPPA support New Mexico's regional haze SIP because it provides a cost-effective means of significantly reducing the San Juan Generating Station's contribution to regional haze without imposing an undue burden on our customers. It also contributes to meeting New Mexico's first interim goals along a long-term path to improve visibility and restore Class I areas to natural conditions by 2064, as required by the Clean Air Act. In contrast, EPA does not appear to have given any consideration to how its regional haze FIP for the San Juan Generating Station would affect hundreds of thousands of ratepayers in California, New Mexico and Utah, nor has EPA weighed the plan's possible adverse effects to the reliability of the transmission system.

EPA grossly underestimated the cost of its implementation plan. Bids received last month for installation of the FIP-mandated emissions control technology -- Selective Catalytic Reduction (SCR) -- at the San Juan Generating Station ranged from $750 million to $805 million, not including engineering, project management and insurance costs estimated to be about $48 million. These real-world estimates are more than twice EPA's latest estimate of $345 million to retrofit SCR emissions controls at the San Juan Generating Station. The EPA contractor that prepared the estimate failed to consider or include consideration for a number of significant cost drivers specific to the San Juan Generating Station, such as plant elevation, physical limitations within the plant footprint, and the scope of the equipment required. The minimal visibility gains offered by the EPA's FIP over the New Mexico state plan would not justify the added cost even if EPA's original estimate were correct, and they certainly do not justify a price tag more than 10 times the size of the New Mexico's SIP.

EPA's regional haze FIP for the San Juan Generating Station could also affect the reliability of the electric grid in the Southwest. Although the five-year implementation schedule currently mandated by the FIP is feasible, though challenging, Wildearth Guardians and other environmental organizations have petitioned the federal courts to require a three-year implementation schedule. Because completing the installation of SCR emissions controls on a three-year schedule is not feasible, each of the units of the San Juan Generating Station would have to be shut-down in the fourth and fifth years (2015-16) until their individual upgrades are complete. M-S-R commissioned a preliminary study of the reliability impacts of a shutting down all four units of the San Juan Station on either a short-term or permanent basis. This study found that while there is enough unutilized electric power in the Western United States to replace the San Juan plant's generation, moving that power to where it is needed would cause overloads and possible instability on portions of the transmission grid in New Mexico, Arizona and Colorado, violating North American Electric Reliability Corporation (NERC) Standards that are intended to ensure the reliability of the bulk power system in North America.

Both the State and EPA plans pose a special quandary for the California owners of the San Juan Generating Station because fulfilling the Clean Air Act requirements at the San Juan plant is seen by some as a violation of one of California's greenhouse gas (GHG) laws. That law (SB 1368) prohibits publicly owned utilities from investing in power plants whose carbon dioxide (CO_2) emissions exceed a state standard equivalent to CO_2 emissions levels from a natural gas plant. While the San Juan Generating Station exceeds that standard, California's law allows existing contractual and ownership obligations to remain in place and exempts routine maintenance work at these facilities.

However, the Sierra Club and the Natural Resources Defense Council (NRDC) have recently asked the California Energy Commission to issue rules that would effectively prevent the M-S-R and SCPPA utilities from fulfilling their contractual obligations to help pay for regional haze improvements at the San Juan Generating Station that are necessary to meet the requirements of federal law.

The Sierra Club and NRDC have also questioned whether investments by California public power agencies in *existing* environmental upgrades at the San Juan Generating Station violated California's GHG law. Over the last decade the San Juan Generating Station owners have invested more than $430 million to install additional emissions control equipment, including the nation's first full-scale mercury removal systems. In fact, the San Juan Generating Station is compliant with the EPA's MACT rule. The most recent environmental retrofit was completed in 2009 at a cost of about $320 million. These improvements have cut the plant's NOx emissions by 44 percent, reduced sulfur dioxide (SOx) and particulate matter by more than 70 percent and enabled a 99 percent mercury removal efficiency rate. But the Sierra Club and NRDC allege that these environmental improvements may be illegal investments by the M-S-R and SCPPA utilities --- even though the Sierra Club was signatory to the Consent Decree requiring San Juan's owners to perform the upgrades.

The California utilities that are part of M-S-R and SCPPPA are non-profit agencies charged with the delivery of affordable, reliable energy to their customers. Fulfilling that mandate has become increasingly difficult as California's GHG law and renewable portfolio standards have made electricity more expensive. Compliance with just the GHG and renewable energy standard laws alone will cause an estimated 12.9 percent increase in the monthly electric bills of MID customers by 2020. Complying with the EPA Region 6 regional haze FIP for the San Juan Generating Station will add yet more to the ratepayers' burden – at least $50 per year for the average Modesto customer.

But we are hopeful that EPA will consider alternatives to its regional haze FIP for the San Juan Generating Station. On April 26, New Mexico Governor Susana Martinez asked EPA to stay its regional haze FIP so that the State, EPA and PNM can work toward an agreeable alternative to both the EPA and the New Mexico regional haze plans. We appreciate and support the Governor's effort.

We also appreciate the Committee's interest in EPA's approach to enforcement of regional haze requirements. This is a national issue. New Mexico's regional haze SIP is one of 37 state regional haze plans that EPA is committed to take action on before the end of this year under the terms of a consent decree settling litigation brought by environmental organizations. Our New Mexico case is an example of how EPA's enforcement of regional haze regulations is neither effective nor mindful of the financial impacts to electric customers.

New Mexico and Federal Implementation Plans

The Clean Air Act includes provisions intended to control emissions that contribute to regional haze that impairs views in national parks and wilderness areas. The Act gives states primary authority on the scope of regional haze remediation, within certain boundaries, requiring the states to take the lead in designing and implementing regional haze plans intended to make "reasonable progress" toward the Act's goal of restoring "natural visibility" in parks and wilderness areas by 2064.

The Act also gives states primary responsibility to make BART determinations for the unique circumstances of each state and emission source. States are given broad discretion in BART determinations because the states are in the best position to understand local conditions and concerns. It is important to understand that the regional haze rule is not a health-based standard and that cost-effectiveness is one of the five factors that must be considered in a BART analysis.

The state of New Mexico drafted a regional haze SIP that would require selective non-catalytic reduction (SNCR) controls to be installed at the San Juan Generating Station. The New Mexico SIP meets the requirements of the Clean Air Act at a total cost of about $77 million for the San Juan Generating Station -- a significant, but manageable cost.

Nevertheless, EPA rejected the San Juan Generating Station portion of the New Mexico SIP, and on August 22, 2011, EPA issued a Final Rule on a FIP to address NOx and SOx emission limits at the San Juan Generating Station. (As previously mentioned, the balance of New Mexico's SIP was just approved by EPA on May 31 of this year.) EPA's regional haze FIP mandates NOx controlled emission rates (0.05 lbs/MMBTU) for the San Juan Station that are not only inconsistent with other recently adopted regional haze FIPs in EPA Region 6 and EPA Region 9 for coal-fired generation, the rates are *five times lower than those mandated* by either the EPA's Regional Haze Provision Authority (0.23lb/MMBTU) or EPA's Good Neighbor Provision Authority (0.28 lb/MMBTU). To accomplish the aggressively low rate of 0.05 lb/MMBTU, EPA's San Juan Generating Station FIP mandates the use of SCR technology that is far more costly than the similarly effective SNCR technology included in New Mexico's SIP.

We are particularly concerned that even after spending almost a billion dollars to comply with EPA's regional haze FIP requirements, we may still not be in compliance. Firms bidding to install the SCR controls at the San Juan Generation Station informed PNM that they could not guarantee that the NOx emission rate mandated by EPA's FIP could be achieved at San Juan and that sulfuric acid emissions could not be reliably measured at the level that the FIP requires.

Making reasonable progress toward improving visibility over a 60-year period should not require huge investments for minimal or imperceptible benefits. EPA also must use the best available science when projecting visibility improvements for its preferred SCR technology. EPA's outdated visibility modeling exaggerates the visibility improvements of SCR and the corresponding cost effectiveness[2].

[2] Petition of Public Service Company of New Mexico for Reconsideration and Stay of EPA's Final Rule: "Approval and Promulgation of Implementation Plans; New Mexico; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology Determination" October 21, 2011, Page 44 (Docket No. EPA-R06-OAR-2010-0846)

Impact to California households and businesses

M-S-R has analyzed the potential cost impacts of the installation of the EPA-mandated SCR technology at the San Juan Generating Station based on an $800 million-to-$805 million estimate confirmed by the recent construction bids. M-S-R's share of the costs for its 28.8-percent interest in San Juan Generating Station Unit No. 4 are assumed to be covered by the issuance of $85 million in new tax-exempt debt to be amortized over a 10-year period coterminous with existing debt stemming from M-S-R's original ownership purchase of the San Juan Unit No. 4 in 1983. The increase in annual debt service would represent a 15-percent increase in the delivered cost of San Juan Generating Station power to M-S-R's members. On an individual member agency basis, the total cost increase for the next decade are $460 per customer for the City of Redding electric utility, $620 per customer for the MID and $920 per customer for the City of Santa Clara's utility.

SCPPA member cities Azusa, Banning, Colton, Glendale, and the Imperial Irrigation District collectively own 42 percent of San Juan Generating Station Unit 3, and Anaheim owns 10 percent of San Juan Generating Station Unit 4. The cost their customers would incur to upgrade to the SCR technology in EPA's plan would collectively be as much as $143 million. The total cost impact to each SCPPA owner is different based on its individual resource mix, but the impact is significant. For example, each of Glendale Water and Power's 83,000 customers would pay an additional $272, whereas Azusa Light and Water's 15,000 customers would pay $2,250 each toward the total cost of the SCR retrofit. Approximately 140,000 customers of the Imperial Irrigation District, who reside in one of California's poorest counties with some of the highest unemployment, would each face $850 in added costs.

Congressional Concerns

To highlight the impact EPA's plan would have on California electricity customers, a bipartisan group of 10 California Members of Congress *(Reps. Joe Baca (D), Jerry Lewis (R), Bob Filner (D), Mary Bono Mack (R), Dennis Cardoza (D), Gary Miller (R), Jim Costa (D), Wally Herger (R), Tom McClintock (R) and Jeff Denham (R))* wrote letters to EPA Administrator Lisa Jackson encouraging EPA to fully consider the information in the New Mexico SIP and take appropriate action. The California legislators expressed support for meeting federal regional haze requirements and asked EPA to carefully consider the significant rate impact that a SCR-based FIP would have on their constituents. They also emphasized that the regional haze requirements are a visibility-based standard that are supposed to be meet with the "best available control technology," which is defined in part by cost-effectiveness. Moreover, the bipartisan group of Members noted the significant environmental investments that the San Juan Generating Station's California owners are making to meet stringent California energy requirements, including requirements that utilities achieve a 30-percent reduction in GHG emissions and meet a 33-percent renewable energy standard by 2020.

Reliability Impacts

EPA's FIP for the San Juan Generating Station requires installation of the SCR controls over a five-year period; that clock started running last September. Environmental organizations that support EPA's efforts to mandate the more expensive SCR technology at the San Juan Generating Station, and at other coal plants in the nation, have asked the federal courts to impose a three-year installation schedule that cannot be achieved without shutting down multiple units of the San Juan Generating Station during the fourth and fifth year of the construction period until the retrofits are completed and tested. M-S-R asked Navigant Consulting, Inc. (Navigant) to undertake a preliminary assessment of the potential impacts on the transmission system if the San Juan Generating Station was taken out of service during 2015 and 2016. The study (summary attached) focused on potential reliability impacts to the transmission grid for the region encompassing Arizona, New Mexico, the El Paso area of Texas, southwestern Colorado and southeastern Utah.

The preliminary assessment (which included power-flow analyses only) indicated that operating the regional transmission system with the San Juan generation off-line could:

- Result in new post-contingency transmission line overloads (of as high as 6%) on existing 230-kV and 115-kV lines in northern Arizona, northern New Mexico and southwestern Colorado.
- Increase the number and/or severity of the post-contingency transmission line overloads noted on two 115-kV lines in northeastern New Mexico, which are interconnected with the existing 230-kV line between the Walsenburg Substation in southern Colorado and the Gladstone substation in northeastern New Mexico.
- Result in post-contingency transmission voltage deviations of as high as 13% at the Ojo 345-kV bus in northern New Mexico.

It is possible that such large voltage deviations could be an indication of potential system instability, but determining if this is the case would require additional studies. Transmission system overloads or voltage instability would likely violate NERC standards that are intended to ensure the reliability of the bulk power system. If a shut-down of the San Juan Generating Station were to cause transmission system overloads or voltage instability, NERC standards that could be violated include standard BAL-STD-002 (sufficient locational operating reserves), standard BAL-004-WECC-01 (transmission line frequency maintenance), standard TOP-007-WECC-1 (System Operating Limits), and standard TOP-STD-007-0 (Operating Transfer Capacity Limits). Remedial Action Schemes (RAS) for the affected transmission lines would need to be reviewed, revised, and/or otherwise upgraded. With substantially less generation available, a Transmission Operator may have difficulty restoring its system within acceptable time limits dictated by standard PRC-SDT-003-1.

California Energy Commission

California's GHG emissions law (SB) 1368 -- (*Perata, Chapter 598, Statutes of 2006*) required the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) to establish a GHG emissions performance standard and to implement regulations for all long-term financial commitments in baseload generation made by investor-owned and publicly owned utilities.

The California Emissions Performance Standard adopted by the CEC is 1,100 pounds (0.5 metric tons) of carbon dioxide (CO_2) per megawatt hour (MWh) of electricity, which is the rate of emission of GHG for combined-cycle natural gas baseload generation. Coal-fired power plants do not meet this standard. However, as the CEC has stated, *"SB 1368 is not intended to shut down currently operating power plants or lead to their deterioration..."* Rather, the purpose of the law is to reduce financial risks to electric consumers by ensuring that utilities do not make substantial investments to build new (coal-fired) power plants or extend the lives of existing plants where those investments are likely to result in additional environmental compliance costs under future GHG limitations. The law prohibits California utilities from acquiring or increasing ownership interests in plants that do not meet the California Emissions Performance Standard and prohibits investments that have the potential to extend the life of existing generating units by five years or more, or to increase generating capacity. Investments for routine maintenance are exempted. M-S-R and SCPPA believe that upgrades to meet federal environmental laws are part of power plant maintenance as mandated by the standard of Prudent Utility Practice.

In November, 2011, the NRDC and the Sierra Club filed a petition with the CEC alleging that publicly owned utilities, including M-S-R and SCPPA, have made past investments and plan to make future investments in existing baseload generation facilities that violate the intent of SB 1368. Specifically, the NRDC and the Sierra Club have questioned whether the California agencies with ownership interests in the San Juan Generating Station violated state law by helping to pay for environmental upgrades completed in 2009, including the nation's first full-scale mercury removal system. They cite as an example of future prohibited investments the retrofitting the San Juan Generation Station to comply with federal Clean Air Act regional haze requirements, contending that such environmental mandates are intended to "extend the life of the plant" and therefore clearly trigger the EPS restriction. The NRDC and the Sierra Club also question whether California law will allow the installation of groundwater pollution prevention improvements at the San Juan Generating Station, notwithstanding the fact that the Sierra Club recently entered into a consent decree requiring those improvements. The consent decree also requires the Sierra Club to support all approvals necessary for the San Juan Generating Station owners to install the groundwater protections.

In other words, NRDC and the Sierra Club argue that in the case of San Juan Generating Station, compliance with federal environmental law is a violation of California environmental law.

The NRDC and the Sierra Club have asked the CEC to modify its regulations to require that utilities submit for CEC review and approval *all* expenditures at non-Emissions Performance Standard - compliant plants, and that the CEC clarify that SB 1368 prohibits investments to bring existing coal plants into compliance with current environmental laws. The CEC has initiated a new Rulemaking (12-OIR-01) to look at whether changes to the California Emissions Performance Standard are necessary and the Commission is working to develop the scope of that proceeding.

The NRDC and the Sierra Club say that the California owners of the San Juan Generating Station should simply decline to make the investments necessary to bring the plant into compliance with federal regional haze standards. In their petition, the environmental organizations say that if the California owners were to refuse to pay their share of the regional haze improvements at the San Juan Generating Station, "those improvements should not go forward." The clear but unstated result would be closure of the plant.

But M-S-R and SCPPA utilities cannot simply decline to make the investments at San Juan that are necessary to comply with federal laws. We do not think that the regional haze FIP issued by EPA Region 6 complies with the Clean Air Act, but if the FIP is ultimately upheld, we are required by law and contract to comply with it. As public agencies we cannot choose to ignore such mandates on the basis of cost of compliance. Further, M-S-R's investment in the San Juan Generation Station was financed with tax-exempt bonds, and the agency has obligations and fiduciary duties to its bondholders and ratepayers.

National Issue

The New Mexico SIP is one of three dozen regional haze plans that will be acted on by EPA this year under the terms of a consent decree reached between EPA and environmental organizations in regional haze litigation (*National Parks Conservation Association v. Lisa Jackson*). The environmental groups brought the litigation because the states and the EPA are far behind schedule in developing implementation plans for regional haze, which were supposed to have been completed by 2008.

Under the Nov. 9, 2011 consent decree, EPA must now issue a multitude of decisions approving or disapproving state plans by the end of 2012. Where EPA disapproves a SIP, it must institute a FIP instead. EPA's response to some of these SIPs has raised the same issues and questions associated with EPA's approach to enforcement of regional haze regulations at the San Juan Generating Station in New Mexico. Last December, a federal court supported North Dakota's decision to use the less-expensive SNCR technology at several power plants rather than the far more costly SCR controls sought by EPA. The decision (*United States of America and State of North Dakota v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative)* affirmed that states have the primary role in making BART determinations. Legislation (H.R. 3379) introduced in the House last year would mandate that states have sole discretion, after considering certain economic factors, in determining emission limits, schedules of compliance, and other measures for each applicable implementation plan for a state for any area that is listed as contributing to impairment of visibility.

Conclusion

The California public agencies that have an ownership interest in the San Juan Generating Station are willing to do their share to ensure cleaner air and improved visibility with cost-effective improvements that are intended to bring the plant into compliance with Clean Air Act standards. That is why we support the New Mexico SIP. But our ratepayers – ordinary households and businesses – should not be required to pay for extremely costly emissions controls that produce only marginal benefits as compared to less costly but similarly effective alternatives. The environmental organizations that support such costly improvements do not hide the fact that their goal is to shut down plants such as the San Juan Generating Station. Closure of the San Juan Generating Station is the clear purpose of the NRDC and Sierra Club effort to enjoin the California owners from fulfilling their contractual obligations to help pay for regional haze improvements at the San Juan Station.

Thank you for your attention. I am happy to answer any questions that you may have.

ATTACHMENTS:

M-S-R Public Power Agency white paper on Reliability Impacts of San Juan Station Shut-Down

Comparison photos of visibility improvements

CHART- Status of Regional Haze SIPs

Reps. Denham-Cardoza Letter to EPA re SJGS FIP

Rep. Filner Letter to EPA re SJGS FIP

Reps. Lewis-Bono-Mack Letter to EPA re SJGS

EPA Letter to Rep. Bono Mack re SJGS FIP

Sierra Club-NRDC Petition to CA Energy Commission

WEST Associates Letter to EPA on regional haze

M-S-R Public Power Agency

San Juan Generating Station
System Reliability Impacts
March 2012

M-S-R Public Power Agency

- M-S-R Public Power Agency is composed of three public power utilities in Central California; Modesto Irrigation District, City of Santa Clara, and City of Redding

- M-S-R Public Power Agency employs a mix of renewable and thermal generation resources to provide electricity to 210,000 residential and commercial customers in a three-county area.

San Juan Generating Station (SJGS)

- The San Juan Generating Station (SJGS) is a four-unit 1680 MW thermal-electric coal-fired power plant located near Farmington, NM.

- M-S-R owns a 28.8-percent undivided interest in Unit No. 4 of the SJGS, which provides 150 MW annually to M-S-R's California customers.

EPA Regional Haze Federal Implementation Plan (FIP)

- In August 2011 EPA issued a Federal Implementation Plan (FIP) for the SJGS requiring installation of additional pollution controls intended to reduce emissions that contribute to regional haze. In June 2011 the New Mexico Environmental Department issued a far less burdensome yet equally effective State Implementation Plan (SIP) – that has not been acted on by EPA.

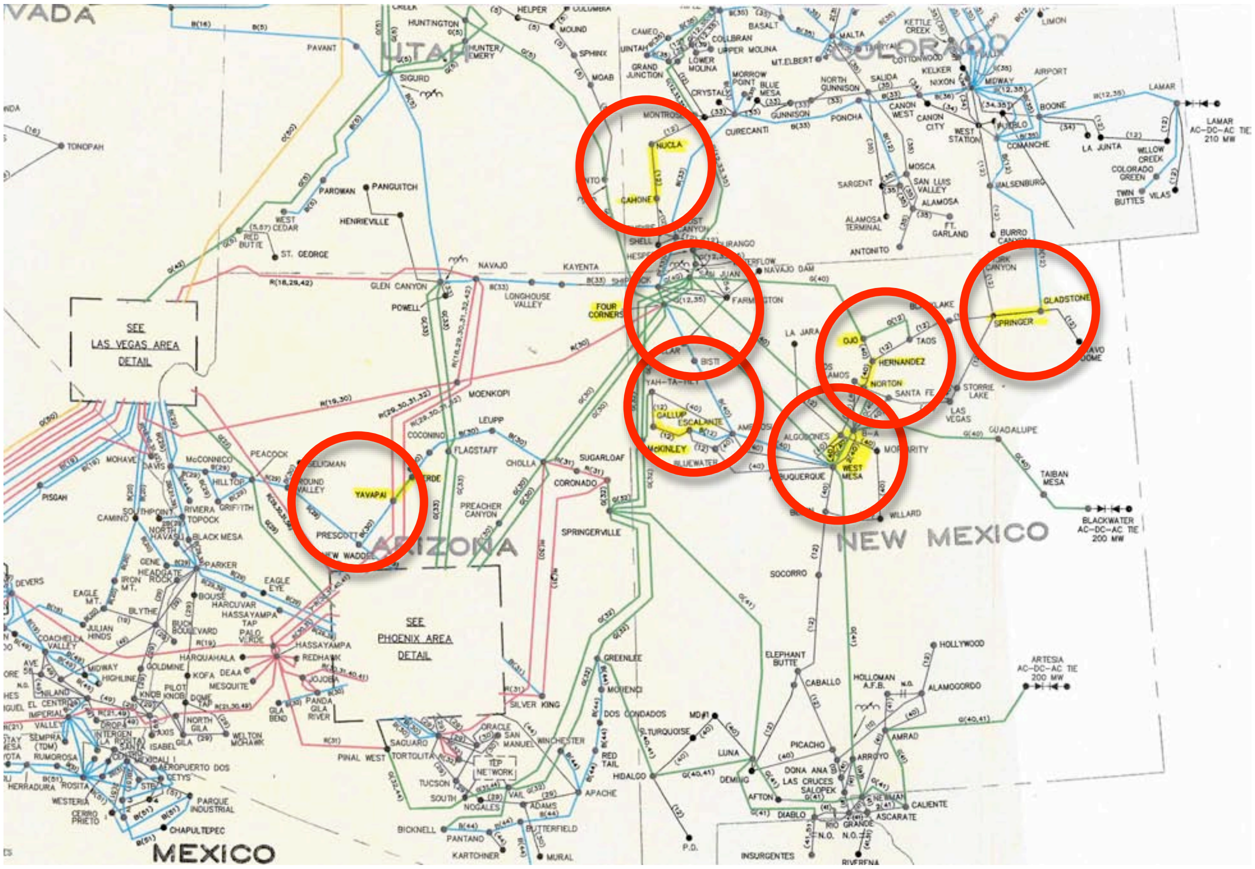
- EPA's regional haze rule ignores electric grid reliability impacts. Federal Energy Regulatory Commissioner Moeller testified before Congress September 14, 2011 "the federal government needs to convene an open and transparent process to assess the reliability implications of the EPA rules individually and in aggregate."

- M-S-R identified potential electric grid reliability impacts resulting from EPA's rule in comments (November 28, 2011) and supplemental comments (December 9, 2011) filed before FERC in AD-12-1-000 and has confirmed those concerns in recent powerflow studies.

Reliability Impacts (Detailed Report Attached)

- Shutdown of SJGS would result in significant transmission system impacts.
  - New post-contingency overloads in northern AZ, northern NM and southwestern CO.
  - Increases in the number and/or severity of the post-contingency overloads in northeastern NM and interconnections with southern CO and northeastern NM.
  - Post-contingency voltage deviations in northern NM.
  - Potential voltage instability indicated.

Locations of Impacted Transmission Facilities:



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**REPORT ON THE
PRELIMINARY ASSESSMENT OF THE IMPACTS
IF SAN JUAN UNITS 1-4 WERE OFF-LINE
DURING THE 2015-2016 TIME FRAME**

EXECUTIVE SUMMARY

The M-S-R Public Power Agency (M-S-R) presently owns 28.8% (approximately 146 MW) of capacity in the 507 MW Unit 4 at the San Juan Generating Station (San Juan), which is located in northwestern New Mexico. San Juan consists of four units with a total capacity of 1,684 MW. The United States Environmental Protection Agency has stated that all four units at San Juan need to be retrofitted to meet new emissions standards. Due to the anticipated costs for the potential retrofits and the timing to accomplish such, M-S-R has asked that Navigant Consulting, Inc. (Navigant) undertake a preliminary assessment of the potential impacts on the transmission system in the Study Area (i.e. Arizona, New Mexico, the El Paso area of Texas, southwestern Colorado, and southeastern Utah) if the San Juan units were out-of-service in the 2015-2016 timeframe.

This preliminary assessment (which is discussed in greater detail below) assumed that:

- The existing coal-fired generation at Apache Units 1 and 2, Cholla Units 1-3, Coronado Units 1 and 2, Escalante Unit 1, Four Corners Units 4 and 5, Navajo Units 1-3, and Springerville Units 1-4 (a total of approximately 7,300 MW of capacity) would remain in service, and
- Based on the modeling in the selected WECC powerflow case, enough "underutilized" gas-fired generation located in Arizona and California would be available to replace and coal-fired generation that was modeled as retired or off-line in the studies. A majority of such generation is "non-utility" owned.

This preliminary assessment (which included powerflow analyses only) indicated that operating the system with the San Juan generation off-line could:

- Result in new post-contingency overloads (of as high as 6%) on existing 230-kV and 115-kV lines in northern Arizona, northern New Mexico and southwestern Colorado.
- Increase the number and/or severity of the post-contingency overloads noted on two 115-kV lines in northeastern New Mexico which are interconnected with the existing 230-kV line between the Walsenburg Substation in southern Colorado and the Gladstone substation in northeastern New Mexico.
- Result in post-contingency voltage deviations of as high as 13% at the Ojo 345-kV bus in northern New Mexico. It is possible that such large voltage deviations could be an indication of potential system in-stability. Determining if such was, in fact, the case would require the performance of transient stability studies.

DETAILED DISCUSSION

The preliminary assessment for analyzing the potential impacts if the four units at San Juan were out-of-service during the 2015-2016 time frame consisted of six steps; as follows:

1. Reviewing the latest available WECC summer peak base cases for the 2015-2016 timeframe to select one of the cases for use in the assessment.
2. Modifying the selected case to create a "Reference Case" that reflected the latest publically available information regarding the status of proposed generation and transmission facilities within the Arizona/New Mexico area.
3. Modifying the Reference Case developed as above to create a "Four Corners Retirement Case" which reflected the retirement of Four Corners Units 1-3 that are owned by Arizona Public Service (APS), the "transfer" of the capacity in Four Corners Units 4 and 5 presently owned by Southern California Edison (SCE) to APS, and adjusting thermal generation in the APS and SCE areas to reflect the results of these actions.
4. Modifying the Four Corners Retirement Case as developed above to create a "San Juan Off-Line Case" which reflected taking San Juan Units 1-4 off-line and replacing the "lost" capacity with existing thermal generation in Northern New Mexico, Arizona, California, southern Colorado, and southern Utah as discussed in greater detail below.
5. Comparing the pre- and post-Category B contingency line and transformer loadings and bus voltages within the Study Area for each of the three Cases discussed above and summarizing and comparing the results. The Category B contingencies simulated on each of the three Cases included all 500-kV and 345-kV lines and transformers within the Study Area.
6. Documenting the results of the above analyses in this report.

Development of Reference Case

The initial step in the development of the Reference Case for use in this assessment consisted of reviewing the WECC 2015HS2A powerflow case (approved by WECC in May 2010) and the WECC 2016HS2 powerflow case (approved by WECC in September 2010) to ascertain which case would be most appropriate for these studies. This review indicated that the 2015 case would be the best to use for these studies and, as a result, it was selected for use in developing the Reference Case.

Table 1 summarizes the loads and generation (on a "company-by-company" basis) and losses (on a sub-area basis) modeled in the Arizona/New Mexico/El Paso area in the WECC 2015 summer peak case. As shown in Table 1, the total generation in this combined area is approximately 6,300 MW greater than the loads and losses in the area. It should also be noted that the amounts of generation in Table 1 include:

- Approximately 3,300 MW of generation from the jointly-owned plants in the area that is owned by parties outside of the area, and
- Approximately 7,200 MW of generation owned by independent power producers (IPP's).

TABLE 1 LOADS, LOSSES, AND GENERATION MODELED IN ARIZONA/NEW MEXICO/EL PASO AREAS IN WECC 2015 CASE				
Company	**Load (MW)**	**Losses (MW**	**Total (MW)**	**Generation (MW)**
Arizona Public Service	8,883	-----	-----	13,098
Salt River Project	7,751	-----	-----	8,626
Tucson Electric Power	2,593	-----	-----	2,586
Unisource	519	-----	-----	0
Arizona Electric Power Coop	460	-----	-----	527
Western Area Power	931	-----	-----	3,945
Total – Arizona	21,137	608	21,745	28,782
Public Service of New Mexico	2,261	-----	-----	2,655
Tri-State G&T Cooperative	428	-----	-----	240
Total – No. New Mexico	2,689	164	2,853	2,895
El Paso Electric Area	1,944	64	2,008	1,279
Total Study Area	25,770	836	26,606	32,956

Table 2 presents additional information regarding the generation mix for those utility systems with which jointly owned projects or IPP projects are interconnected. As noted in Table 2, the IPP generation includes 1,200 MW from the proposed Desert Rock Powerplant in the Four Corners area and 500 MW from the proposed Bowie power project in southeastern Arizona. All of the remaining 5,500 MW of IPP generation listed in Table 2 is from existing projects (primarily in the Palo Verde area).

TABLE 2 GENERATION MIX IN ARIZONA/NEW MEXICO/EL PASO AREAS IN WECC 2015 CASE				
Utility System	**Resources**	**Generation (Net MW)**		
		Available	**Dispatched**	**"Excess"**
APS	Self-Owned	4,975	4,975	0
	Four Corners 4 & 5	1,500	1,500	0
	Palo Verde 1-3	3,936	3,936	0
	IPP Projects [1]	3,352	2,687	665
	Total	13,763	13,098	665
SRP	Self-Owned	3,516	3,416	100
	Navajo 1-3	2,243	2,243	0
	IPP Projects	2,968	2,968	0
	Total	8,727	8,627	100
TEP	Self-Owned	1,359	1,271	88

[1] Includes 1,200 MW from the proposed Desert Rock Powerplant in the Four Corners area

	Springerville 3 & 4 [2]	815	815	0
	IPP Projects [3]	500	500	0
	Total	2,674	2,586	88
WAPA-DSW	Self-Owned	2,866	2,866	0
	IPP Projects	1,079	1,079	0
	Total	3,945	3,945	0
PNM	Self-Owned	1,394	1,112	282
	San Juan 1-4	1,607	1,543	64
	Total	3,001	2,655	346

The Reference Case for use in these studies was created from the WECC 2015 summer peak discussed above and reflected the following changes:

- Removing the Desert Rock and Bowie projects from the case because neither of these projects have completed their regulatory review and/or not anticipated to be in-service prior to 2018 (based on information in the WECC ***2011 Power Supply Assessment*** (November 17, 2011).
- Increasing generation as follows to replace the 1,700 MW of "lost" generation[4]:
  - 60 MW from San Juan (which increased the dispatched capacity to a level closer to the available capacity)
  - 665 MW from the Gila River IPP project in Arizona,
  - 315 MW from utility owned plants in the SRP and TEP areas,
  - 100 MW from thermal plants in the San Diego area, and
  - 500 MW from thermal plants in the SCE area.

Four Corners "Retirement" Case

Case Development

The Four Corners "Retirement" Case was developed from the Reference Case discussed above by:

- Retiring Four Corners Units 1-3 that are owned by APS and which were modeled in the Reference Case with a combined output of 560 MW.
- Reducing power transfers from the Arizona area to the SCE area by 720 MW[5] to model the "transfer" of SCE's capacity in Four Corners Units 4 and 5 to APS.
- Increasing thermal generation within the SCE area by 720 MW to replace the capacity from Four Corners 4 and 5 and decreasing APS peaking capacity in the Phoenix area to accommodate the 160 MW of additional generation from Four Corners made available to APS via the "transaction" with SCE.

Results of Technical Studies

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[2] Units owned by Tri-State and SRP

[3] Includes 500 MW from the proposed Bowie power project in southeastern Arizona

[4] Due to a decrease in losses the total generation added was approximately 60 MW less than the total generation removed

[5] The Reference Case modeled the total generation from these two units at 1,500 MW; SCE's ownership share (48%) is equal 720 MW

Category B outages of the 345-kV and 500-kV lines and transformers in the Study Area were simulated on both the Reference Case and the Four Corners "Retirement" Case to assess the impacts associated with retiring and re-allocating generation at Four Corners. In summary, these studies indicated that retiring and re-allocating generation at Four Corners:

- Would result in "new" overloads of:
  - About 14% on either of the 345/230-kV transformers at Four Corners.
  - About 8% on the Enron Tap-Gallup 115-kV line in northern New Mexico
- Would increase the number and/or severity of overloads on the following elements:
  - Gladstone-Clapham 115-kV line in northeastern New Mexico – 3% increase in overload
  - Gladstone-Springer 115-kV line in northeastern New Mexico – number of overloads increases from eight to seventeen and the worst overload increases by 4%
  - Hernandez-Norton 115-kV lines in the PNM area – Overloads increase by 2%
  - McKinley-Yahtahey 345/115-kV transformer - Number of overloads increases from one to two and the worst overload increases by 4%
- Would not increase the magnitude of post-outage voltage deviations at the major busses in the study area.

San Juan "Off-Line" Case

<u>Case Development</u>

The San Juan "Off-Line" Case was developed from the Reference Case discussed above by:

- Taking San Juan Units 1-4 (modeled in the Four Corners Retirement Case with a total <u>net</u> capacity of 1,614 MW) off-line.[6]
- Replacing approximately 570 MW of the "lost" capacity with existing, underutilized utility-owned thermal generation within the service areas of the San Juan participants, as follows:
  - Increasing thermal generation in southern Colorado by 40 MW to replace Tri-State's share of San Juan capacity.
  - Increasing thermal generation in Utah by 35 MW to replace UAMP's share of San Juan capacity.
  - Increasing thermal generation in the SCE area by 130 MW to replace the San Juan capacity owned by the municipal utilities within the SCE area (Anaheim, Azusa, Banning, and Colton).
  - Increasing thermal generation in the LADWP area by 20 MW to replace Glendale's share of the San Juan capacity.
  - Increasing thermal generation in the IID area by 104 MW to replace IID's share of the San Juan capacity.
  - Increasing thermal generation in the M-S-R member systems by 144 MW to replace M-S-R's share of the San Juan capacity.
  - Turning on approximately 100 MW of previously unused generation in the PNM area.
- Utilizing the capacity from IPP projects in Arizona which had previously been assumed to be scheduled to California to replace the remaining approximately 1,050 MW of lost

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[6] The total gross capacity of San Juan Units 1-4 modeled in the Four Corners Retirement Case was 1,791 MW and the total station service load for these four units was modeled as 177 MW

generation. This was accomplished by:

- Turning on approximately 50 MW of previously unused thermal capacity in the SCE area, and
- Turning on approximately 160 MW of previously unused thermal capacity in the San Diego area, and
- Turning on approximately 840 MW of previously unused thermal capacity in the PG&E area (such was necessary because there was no additional, unscheduled thermal capacity in the SCE or SDG&E areas).

Results of Technical Studies

Category B outages of the 345-kV and 500-kV lines and transformers in the Study Area were simulated on the San Juan "Off-Line" Case and compared to the results for the Four Corners "Retirement" Case to assess the impacts if the four units at San Juan were off-line. In summary, these studies indicated that taking San Juan off-line:

- Would result in "new" overloads of:
  - As high as 6% on APS's Verde-Yavapai 230-kV line
  - As high as 4% on the Person-Prosperity 115-kV line in the PNM area
  - As high as 2% on the Prosperity-Kirtland 115-kV line in the PNM area
  - As high as 2% on the Nucla-Cahone 115-kV line in southern Colorado.
- Would increase the number and/or severity of overloads on the following elements:
  - Gladstone-Clapham 115-kV line – Number of overloads increases from one to two and the worst overload increases by 2%
  - Gladstone-Springer 115-kV line – Number of overloads does not increase but the magnitude of the worst overload increases by 7%
- Would result in the post-outage voltage deviation at the Ojo 345-kV bus in northern New Mexico increasing by about 4% (from about 9% to about 13%).

Visual Difference Between
New Mexico State Implementation Plan and
EPA Federal Implementation Plan

New Mexico State Implementation Plan costs = $77 million with result of ~5.89 delta dv.

Federal Implementation Plan costs = $750-850 million with a result of ~3.45 delta dv.

Status of Regional Haze SIP Decisions in EPA Regions

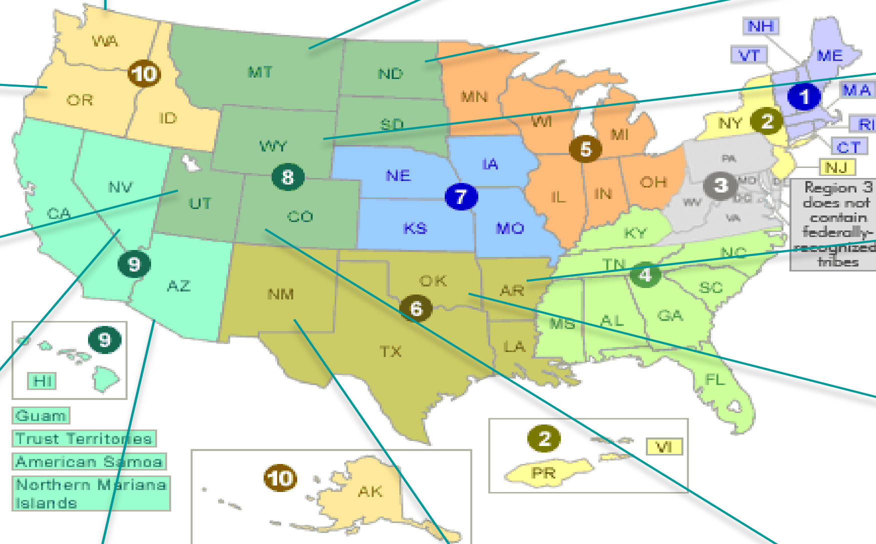
Washington
- Proposed EPA Action due May 15, 2012

Montana
- EPA Proposed FIP March 20, 2012 (MT delegated program)

North Dakota
- EPA Approved SIP on March 2, 2012

Oregon
- EPA approved SIP in part on July 5, 2011
- Remaining elements due Nov 15, 2012

Wyoming
- EPA partial approval proposed May 15, 2012



Utah
- Final EPA Action due Oct 31, 2012

Arkansas
- Final partial approval of SIP March 12,2012

Nevada
- EPA approved SIP in part Dec 13, 2011
- Proposed remaining SIP (Reid Gardner) Apr 2, 2012

Oklahoma
- Final partial EPA Action Dec 2011
- Remaining elements due May 15, 2012

Arizona
- Proposed EPA Action due May 30, 2012

New Mexico
- EPA FIP Sept 21, 2011; proposed action on SIP due May 30, 2012

Colorado
- Proposed EPA approval of SIP on March 8, 2012

Source: WEST Associates, Washington, D.C. May, 2012

Congress of the United States
Washington, DC 20515

November 18, 2011

The Honorable Lisa Jackson
Administrator
Environmental Protection Agency
1200 Pennsylvania Avenue N.W.
Washington, DC 20460

Dear Administrator Jackson:

As U.S. Representatives of a consumer-owned utility that is a partial owner of the San Juan Generating Station (SJGS) in New Mexico, we respectfully request your assistance in meeting federal EPA Regional Haze requirements with the most cost-effective technology described below.

The M-S-R Public Power Agency in California is jointly owned by the Modesto Irrigation District, serving the City of Modesto and portions of Stanislaus and San Joaquin Counties, and the municipal utilities serving the Cities of Santa Clara and Redding. The M-S-R constituent members collectively own 28.8 percent of the SJGS Unit 4. All of these consumer-owned utilities actively support efforts to meet federal EPA Regional Haze requirements. All are making significant and costly investments to meet state energy requirements, including a 30-percent reduction in Greenhouse Gas (GHG) emissions (80 percent by the year 2050) and a 33-percent renewable energy standard by the year 2020.

On June 2, 2011, New Mexico's Environment Department unanimously approved a State Implementation Plan (SIP) to retrofit SJGS with Selective Non-Catalytic Reduction technology (SNCR) to reduce regional haze and meet federal air quality goals. The SNCR option achieves EPA's established presumptive NOx limit, reduces NOx that contributes to haze by an additional 4,900 tons per year and also results in visibility improvements. The plan meets Clean Air Act standards and has an estimated capital installation cost of $74 million.

We understand, prior to the SIP's being approved by the State of New Mexico, U.S.-EPA Region 6 issued its own Federal Implementation Plan (FIP) to meet the same federal air quality goals and subsequently published the same in the Federal Register. The federal plan calls for the installation of Selective Catalytic Reduction (SCR) technology, at a cost of more than $779 million. SCR technology would remove a greater amount of the NOx pollutant; however, the visibility improvement gained is minimal as compared to the New Mexico plan.

M-S-R Public Power Agency and its public power partners, who are charged with the delivery of affordable, reliable energy to their customers, are already making enormous environmental strides as required under California law. The added layer of EPA's SCR requirement at SJGS would be fiscally painful, with each of the M-S-R Public Power Agency constituent member's 210,000 customers obligated to pay up to $660 each for their utility's financed share of the SCR retrofit. This additional cost would be a hard pill to swallow for residents of California's Central Valley, which has some of the highest levels of unemployment in the State.

Before your agency requires a technology that is roughly 13 times the cost of the SNCR and produces minimal visibility improvement, we respectfully request careful consideration of the technical, as well as consumer impacts when analyzing the two options. Further, we note that on August 1, 2011, your Assistant Administrator for Air and Radiation informed my colleagues, the Honorable Mary Bono Mack, the Honorable Gary G. Miller, and the Honorable Joe Baca, that EPA would "fully consider the information in the New Mexico SIP, and take appropriate action."

We respectfully request your assistance with this important matter and that EPA withdraws its FIP; while, pursuant to Section 101 of the Clean Air Act, EPA looks to approve the New Mexico SIP including both its Interstate Transport and Regional Haze components.

Sincerely,

JEFF DENHAM
U.S. Representative

DENNIS CARDOZA
U.S. Representative

BOB FILNER
51st District, California

VETERANS' AFFAIRS COMMITTEE
RANKING MEMBER

TRANSPORTATION AND INFRASTRUCTURE COMMITTEE
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Water Resources and Environment
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website: www.house.gov/filner

June 13, 2011

The Honorable Lisa Jackson
Administrator
Environmental Protection Agency
1200 Pennsylvania Avenue N.W.
Washington, DC 20460

Dear Administrator Jackson:

As a U.S. Representative of a consumer-owned utility that is a partial owner of the San Juan Generating Station (SJGS) in New Mexico, I respectfully request your assistance with regard to federal EPA Regional Haze requirements.

The Imperial Irrigation District (IID), which provides electricity to my California Congressional District, together with the municipal utilities serving the Cities of Azusa, Banning, Colton, and Glendale, collectively own 42 percent of the SJGS Unit 3 through the Southern California Public Power Authority. The City of Anaheim's utility owns 10 percent of Unit 4, directly. All of these consumer-owned utilities actively support efforts to meet federal EPA Regional Haze requirements. All are making significant and costly investments to meet state energy requirements, including a 30 percent reduction in Greenhouse Gas (GHG) emissions (80 percent by 2050) and a 33 percent renewable energy standard by 2020.

On June 2, New Mexico's Environment Department unanimously approved a State Implementation Plan (SIP) to retrofit SJGS with Selective Non-Catalytic Reduction technology (SNCR) to reduce regional haze and meet federal air quality goals. The SNCR option achieves EPA's established presumptive NOx limit, reduces NOx which contributes to haze by an additional 4,900 tons per year and also results in visibility improvements. Its capital installation cost is approximately $70 million, and meets EPA standards.

I understand, prior to the SIP's being approved by the State of New Mexico, U.S. EPA Region 6 issued its own Federal Implementation Plan (FIP) to meet the same federal air quality goals. The federal plan calls for the installation of Selective Catalytic Reduction (SCR) technology, at a cost of more than $900 million. SCR technology would remove a greater amount of the NOx pollutant; however, the visibility improvement gained is minimal.

IID and its public power partners, who are charged with the delivery of affordable, reliable energy to their customers, are already making enormous environmental strides as required under state law. The added layer of EPA's SCR requirement at SJGS would be fiscally painful, with each of the IID's 140,000 customers obligated to pay $850 each for the utility's financed share of the SCR retrofit. A bill this size would be a hard pill to swallow for residents in the Imperial

County, which has some of the highest levels of unemployment in the State. Other California customers would pay as much as $2,250 each.

Before your agency requires a technology that is roughly 13 times the cost of the SNCR and produces minimal visibility improvement, I respectfully request careful consideration of the technical, as well as consumer impacts when analyzing the two options. Further, I hope that EPA will share with me its assessment, prior to release of a final decision affecting our constituents and their investment in SJGS.

Sincerely,

BOB FILNER
Member of Congress

BF/ek
2581566

Congress of the United States
Washington, DC 20515

June 3, 2011

The Honorable Lisa Jackson
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue NW
Washington, DC 20004

Dear Administrator Jackson:

As U.S. Representatives of municipal utilities and local officials who are stakeholders and owners of the San Juan Generating Station (SJGS) in New Mexico, we respectfully request your assistance in moving forward with the most cost effective technology to reduce regional haze related to generation from the plant.

The California utilities run by the Cities of Azusa, Banning, Colton, Glendale, and the Imperial Irrigation District, collectively own 42 percent of the SJGS Unit 3 (through the Southern California Public Power Authority). The City of Anaheim's utility owns 10 percent of Unit 4, directly. All of these consumer-owned utilities actively support efforts to meet federal EPA Regional Haze requirements. These same constituents are on track to make significant and costly strides to achieving state energy requirements, including a reduction in Greenhouse Gas (GHG) emissions by 30 percent (80 percent by 2050) and meeting a 33 percent renewable energy standard by 2020.

On February 28, New Mexico's Environment Department filed a State Implementation Plan (SIP) to retrofit SJGS with Selective Non-Catalytic Reduction technology (SNCR) to reduce regional haze and meet federal air quality goals. Prior to the SIP being filed, U.S. EPA Region 6 issued its own Federal Implementation Plan (FIP) to meet the same federal air quality goals, which calls for the installation of Selective Catalytic Reduction (SCR) technology.

While the SCR technology, at a cost of more than $900 million, would remove a greater amount of the NOx pollutant which contributes to haze, the visibility improvement gained is minimal. SNCR achieves EPA's established presumptive NOx limit, reduces NOx by an additional 4,900 tons per year and also results in visibility improvements. Thus, SNCR is cost-effective at a capital installation cost of approximately $70 million, while still meeting the EPA standards.

These utilities, which are charged with the delivery of affordable, reliable energy to their customers, are already making enormous strides as required under state law (AB 32), including maximizing energy efficiency, increasing their renewable resources to 33 percent by 2020 and meeting GHG reduction requirements. The added layer of EPA's possible SCR requirement at SJGS would be fiscally painful, with each of our constituents having to pay between $272 to more than $2,250 for their utilities' financed share of the SCR retrofit. Before your agency requires a technology that is roughly 13 times the cost of the SNCR and produces minimal visibility improvement, we would respectfully request careful consideration of the technical, as well as consumer impacts when analyzing the two options.

Again, we respectfully request your assistance with this important matter, and that EPA may share with us your decision prior to release of the final decision affecting our constituents and their investment in SJGS.

Sincerely,

Jerry Lewis

JERRY LEWIS
Member of Congress

Mary Bono Mack

MARY BONO MACK
Member of Congress

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

AUG - 1 2011

OFFICE OF
AIR AND RADIATION

The Honorable Mary Bono Mack
U.S. House of Representatives
Washington, D.C. 20515

Dear Congresswoman Bono Mack:

Thank you for your letter of June 3, 2011, co-signed by Congressman Jerry Lewis, requesting that the U.S. Environmental Protection Agency move forward with approval of the most cost effective technology to reduce regional haze-related air pollution from the San Juan Generating Station (SJGS) in New Mexico.

On January 5, 2011, in the absence of an approvable State Implementation Plan (SIP) from New Mexico, we proposed a Federal Implementation Plan (FIP) to address Clean Air Act requirements that emissions from sources in one state do not interfere with the visibility protection programs of other states. In our assessment of New Mexico's sources we found that, with the exception of SJGS, New Mexico's sources are sufficiently controlled with respect to their visibility impacts in other states. For SJGS we proposed specific emission limits to eliminate this source's interference with neighboring states' visibility goals for their national parks and wilderness areas.

As you are aware, we proposed to find that the Best Available Retrofit Technology (BART) to limit emissions of nitrogen oxides (NO_x) from SJGS was selective catalytic reduction (SCR). In proposing this determination, we evaluated all NO_x reduction technologies, including selective non-catalytic reduction (SNCR). We also evaluated the visibility improvement that could be expected to result from the installation of SCR, SNCR and other NO_x control technologies.

Our analyses found that in terms of the amount of NO_x reduced relative to the cost of control, SCR was very cost effective. Other technologies that we evaluated, including SNCR, were less expensive, but did not result in significant visibility improvement. The EPA's proposed estimate of the cost of SCR on all four units at SJGS is well within the range that other states and the EPA have found cost effective as a basis for selection of SCR as BART. We are evaluating comments we received concerning our cost evaluation which may cause us to modify it in our final action.

We are aware of the concerns of the numerous utilities that own an interest in SJGS. Our Region 6 staff has met with management of the facility a number of times to discuss their concerns and I have spoken with them as well. We also appreciate PNM hosting the EPA Region 6 staff on a tour of the facility on May 19, 2011. In response to a request for more time, we also extended our public comment period so all opinions on our FIP could be voiced. Most recently, members of my staff and staff from the EPA's Region 6 and Region 9 offices participated in a conference call with staff from your offices and several of your colleagues' offices to discuss the FIP proposal for SJGS.

We received the New Mexico regional haze SIP on June 24, 2011. This SIP submission includes a revised NOx BART evaluation for the SJGS that would rely on SNCR in lieu of SCR. As part of our NOx BART evaluation for the SJGS, we did consider SNCR in our proposal, but rejected it in favor of SCR, which although more expensive, remained cost effective and is predicted to produce significantly more visibility improvement at the 16 Class I areas we examined. However, we will fully consider the information in the New Mexico SIP, and take appropriate action. In the meantime, we are reviewing and responding to the many comments we received during our comment period and public hearing process. We intend to carefully consider these comments as we make a final decision. As part of this review, we will address the disparity between the EPA and PNM cost estimates.

In light of your interest in this action, we will do our best to make you aware of the Agency's final action on this matter before it is announced publicly and published in the Federal Register. Again, thank you for your letter. If you have further questions, please contact me or your staff may call Diann Frantz in the EPA's Office of Congressional and Intergovernmental Relations at (202)-564-3668.

Sincerely,

Gina McCarthy
Assistant Administrator

JOINT PETITION OF THE NATURAL RESOURCES DEFENSE COUNCIL AND THE SIERRA CLUB
FOR INITIATION OF A RULEMAKING REGARDING
CALIFORNIA'S EMISSIONS PERFORMANCE STANDARD

I. INTRODUCTION

Pursuant to Title 20, Section 1221 of the California Code of Regulation,[1] the Natural Resources Defense Council (NRDC) and Sierra Club jointly file this petition to request the California Energy Commission (CEC) initiate a rulemaking proceeding to ensure that current practices of California publicly-owned utilities (POUs) meet the requirements of Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006) and California's Emissions Performance Standard (EPS). Specifically, NRDC and Sierra Club request the following actions:

(1) modify Section 2907 to require mandatory reporting requirements when POUs make investments in existing coal plants; and

(2) clarify that under current law, POU investments in existing coal plants are subject to the filing requirements of Sections 2908 and 2909.

A review of past and planned expenditures at existing coal power plants owned or contracted to California POUs shows that POUs have made and plan to make substantial capital investments in plants that do not meet the EPS. In light of these past and planned expenditures, we request that the CEC initiate a rulemaking to amend its existing regulations implementing the EPS in order to ensure ongoing transparency and monitoring of any investment at POU-owned and contracted coal plants. As part of this rulemaking, we request that the CEC clearly articulate a set of criteria for POUs to consider in determining whether a particular investment is subject to the requirements of SB 1368 and the EPS.

At this time, NRDC and Sierra Club do not seek to initiate an enforcement action for any particular violation of the EPS. Rather, we request a prospective rulemaking to clarify that POUs fully understand the requirements imposed by the EPS and to ensure that future investments by POUs do not violate existing law. Nothing in this petition constitutes a waiver by NRDC or Sierra Club of their right to request at a later date an enforcement action pursuant to Section 2911 for past or future violations of the EPS.

II. BACKGROUND

[1] Unless otherwise stated, all further references to code sections refer to the Energy Commission's regulations under Title 20 of the California Code of Regulations.

SB 1368 was signed into law on September 29, 2006. The law requires the California Public Utilities Commission (CPUC) and the CEC to establish a greenhouse gas emissions performance standard and to implement regulations for all long-term financial commitments in baseload generation made by load serving entities (LSEs) and POUs, respectively. The CPUC adopted its regulations for the investor-owned utilities (IOUs) and other LSEs in January, 2007. The CEC adopted EPS regulations for POUs in October 2007.[2]

The regulations implemented by the CPUC and CEC under SB 1368 are expected to result in significant GHG emissions reductions. The greenhouse gas emissions performance standard is not to exceed the rate of greenhouse gases emitted per megawatt-hour associated with combined-cycle, gas turbine baseload generation. The CEC's regulations establish an emissions performance standard of 1,100 pounds (0.5 metric tons) of carbon dioxide per megawatt hour of electricity. This standard was established in consultation with the CPUC and the California Air Resources Board and is the same standard adopted by the CPUC.

The objectives of the EPS regulations are to avoid new long-term investments in highly polluting power generation to minimize the significant and under-recognized cost of greenhouse gas emissions, and to reduce potential financial risk to California consumers for future pollution-control costs. The law has two effects: (1) to close off the possibility of California utilities or energy service providers (ESPs) developing or signing new contracts with baseload power plants that do not meet the EPS; and (2) to require California utilities and ESPs to refrain from making any new ownership investments in their existing non-compliant coal plants, unless they can bring those plants into compliance with the EPS.

Since the passage of the California EPS, no California utility has proposed investment in the development or purchase of new coal plants. Utilities appear to clearly understand that the EPS prohibits investments in new coal plants without carbon capture and sequestration because they would not meet the standard. However, past and planned expenditures at existing coal plants suggest that utilities do not properly understand the requirements of the EPS with respect to existing plants.

III. TIMING

Recent and upcoming EPA regulations will require owners of existing coal-fired power plants to decide whether to make significant capital investments in environmental compliance retrofits, or whether to pursue a different strategy that could lead to retirement or natural gas re-powering of coal plants. As discussed in more detail below, all existing coal plants are "non-deemed compliant" facilities under the EPS because their greenhouse gas emissions exceed the standard. Yet California faces the prospect that several POUs will commit hundreds of millions of dollars toward compliance retrofit costs to these facilities. Such investments could significantly extend the effective lives of these plants, contrary to the intent of SB 1368. The CEC's oversight is therefore

[2] 20 CCR 11 § 2900 *et seq.*

necessary to provide a clear and transparent criteria and review of all POU long-term capital investments in coal-fired power plants.

IV. Identification of Petitioners (§ 1221(a)(1))

NRDC is a non-profit membership organization with over 250,000 members and online activists in California and a longstanding interest in minimizing the societal costs of the reliable energy services that Californians demand. Sierra Club is a national, non-profit membership organization with over 600,000 members nationwide, and over 150,000 members in California. Sierra Club's most important priority is to help speed the country's transition from an energy economy dependent on fossil fuels to a robust clean energy economy based on renewable energy.

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V. Nature of Existing EPS Requirements For Investments in Existing Facilities (§ 1221(a)(2))

The CPUC monitors proposed investments in non-compliant facilities by California's IOUs. Last year the CPUC ruled on a petition for modification from Southern California Edison (SCE) regarding SB 1368's applicability to proposed retrofit investments at the Four Corners coal plant in New Mexico.[3] The CPUC's ruling explicitly limited new long term investments by SCE in the plant. The ruling provided a clear signal to SCE and other IOUs that California law does not allow further investments in non-compliant facilities.[4]

Similar to the IOUs, various California POUs have significant contractual or ownership stakes in out-of-state coal plants that do not meet the EPS. (See Attachment 2.) However, unlike the CPUC, the CEC does not yet require a transparent review of proposed investments at these coal plants. As a result, it is unclear whether POUs have consistently complied with the EPS, or whether POUs have misinterpreted the applicability of the CEC regulations with respect to investments in existing facilities.

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[3] D.10-10-016 October 14, 2010 (R. 06-04-009).

[4] Id.

The prohibition in SB 1368 against further capital investment in coal-fired power plants is clear, providing that:

> No load-serving entity or local publicly owned electric utility may enter into a long-term financial commitment unless any baseload generation supplied under the long-term financial commitment complies with the greenhouse gases emission performance standard established by the commission, pursuant to subdivision (d), for a load-serving entity, or by the CEC, pursuant to subdivision (e), for a local publicly owned electric utility.[5]

Thus far, the CEC has not monitored investments in existing coal-fired power plants that are currently under contract to California POUs, none of which meet the EPS. To this point, **not a single POU has submitted compliance filings for covered procurements at existing power plants**. This lack of transparency is likely the result of a potentially incorrect and non-uniform interpretation by POUs of the compliance requirements established by the CEC.

The CEC's EPS regulation, at 20 CCR 11 § 2907, allows a POU to request CEC review of proposed investments or "prospective procurements."[6] POUs must also make compliance filings under 20 CCR 11 § 2908 and 2909 for "covered procurements,"[7] which the regulations define to include "new ownership investments."[8] Notwithstanding these provisions, not a single POU has filed a request for review or a compliance filing for investments in existing coal plants.[9] These omissions presumably stem from unilateral determinations made by POUs that such investments are not "prospective procurements" or "covered procurements" and therefore are not subject to the CEC's regulations. This interpretation by POUs has potentially led to incorrect and non-uniform interpretations of the definitions of "covered procurement" and "new ownership investment":

> "Covered procurement" means:[10]
> ***(1) A <u>new ownership investment</u> in a baseload generation powerplant***, or
> (2) A new or renewed contract commitment, including a lease, for the procurement of electricity with a term of five years or greater by a local publicly owned electric utility with:
> (A) a baseload generation powerplant, unless the powerplant is deemed compliant, or

[5] Cal. PU Code 8341 (a)

[6] 20 CCR 11 § 2907

[7] 20 CCR 11 §2901 (d)

[8] 20 CCR 11 §2901 (j)

[9] CITE (make at least some mention of how we know that)

[10] 20 CCR 11 §2901 (d) (emphasis added)

(B) any generating units added to a deemed-compliant baseload generation powerplant that combined result in an increase of 50 MW or more to the powerplant's rated capacity.

"New ownership investment" means:[11]

(1) Any investments in construction of a new powerplant;
(2) The acquisition of a new or additional ownership interest in an existing non-deemed compliant powerplant previously owned by others;
(3) Any investment in generating units added to a deemed-compliant powerplant, if such generating units result in an increase of 50 MW or more to the powerplant's rated capacity; or
(4) Any investment in an existing, non-deemed compliant powerplant owned in whole or part by a local publicly owned electric utility that:
(A) is designed and intended to extend the life of one or more generating units by five years or more, not including routine maintenance;
(B) results in an increase in the rated capacity of the powerplant, not including routine maintenance; or
(C) is designed and intended to convert a non-baseload generation powerplant to a baseload generation powerplant.

The CEC's EPS compliance requirements apply to "covered procurements," which in turn incorporates the term "new ownership investments." While "new ownership investments" clearly include construction of new powerplants, POUs appear to have interpreted the term to exclude various types of investments in existing coal facilities. For example, the Southern California Public Power Authority (SCPPA) issued a resolution in 2009 finding that a proposed investment in the San Juan Generating Station "constitutes routine maintenance and is not a 'Covered Procurement' pursuant to the regulations promulgated by the California CEC…pursuant to SB 1368."[12] While we make no judgment at this time on SCPPA's determination regarding the applicability of SB 1368 to that particular investment, it is an example of the type of non-uniform and *ad hoc* interpretation that raises concern.

As discussed further below, NRDC and Sierra Club found ample reason to believe that California POUs have made investments and are considering further significant investments in existing coal plants that do not meet the EPS. Although the POUs may have reason to believe that making, or considering, investments in coal plants are not

[11] 20 CCR 11 §2901 (j)

[12] SCPPA Resolution No. 2009-23, February 19, 2009 (Attachment 3).

"new ownership investments" subject to the EPS, under current practices those determinations are not independent or subject to public scrutiny.

We request that the CEC develop clear criteria for POUs to guide them in determining whether a particular investment in an existing plant is subject to the filing requirements of 20 CCR 11 §§ 2908 and 2909.

We further urge the CEC to amend its reporting and compliance regulations to require the POUs to submit compliance filings for all past[13] and planned investments in plants not meeting the EPS. Such a filing would allow the CEC to publicly, transparently, and consistently review past and planned investments to independently determine compliance with SB 1368 in a manner that individual review by POUs cannot achieve.

VI. A REVIEW OF PAST AND PLANNED INVESTMENTS DEMONSTRATES A NEED FOR CEC RULEMAKING (§ 1221(A)(3))

A. Existing Ownership Interests

The table included at Attachment 2 identifies the California POUs that have significant interests in out-of-state coal power plants, which do not meet the EPS. During the period after the passage of SB 1368, POUs continued to make substantial capital investments in several coal plants. The following are a few examples of such investments.

1. San Juan Generating Station

The San Juan Generating Station provides a troubling example of continued long-term investments by California POUs in an old and dirty facility that does not meet the EPS.

- In response to a 2005 consent decree, the owners of the San Juan Generating Station began a four-year $340 million pollution upgrade project to bring the plant into compliance with air quality laws for particulate matter, NO_X, and SO_2 emissions.[14] SCPPA alone paid approximately $80 million in capital costs.[15]
- On February 19, 2009, SCCPA authorized the replacement of a high pressure/intermediate pressure turbine for San Juan Generating Station unit 3.[16] At the time SCPPA made its decision to undertake this upgrade, PNM

[13] Commencing with the passage of SB 1368 in September, 2006.

[14] Rebuttal Testimony in Support of Stipulation of Patrick J. Themig, *In the Matter of the Application of Public Service Company of New Mexico for Revision to its Retail Electric Rates, etc.*, April 25, 2011, New Mexico Public Regulation Commission Case No. 10-00086-UT, p.7.

[15] SCPPA San Juan Unit 3 Status Report, July 2008 (Attachment 4).

[16] SCPPA Resolution No. 2009-23, February 19, 2009 (Attachment 3).

estimated the total cost for the turbine at approximately $14.3 million.[17] SCPPA's resolution approving the expenditure concluded that for purposes of SB 1368, the turbine replacement constituted "routine maintenance" and therefore did not violate the emission performance standard. However, there is no CEC guidance or history of enforcement that indicates whether SCPPA's own interpretation of the turbine expense as "routine maintenance" is valid.

- In 2009, SCPPA reported a $7 million advance payment of O&M in the San Juan Project.[18]

2. <u>Intermountain Power Project (IPP)</u>

Over the past several years, the owners of the IPP coal-fired units in Utah made several substantial modifications, including cooling tower additions, high pressure turbine replacements, boiler capacity additions, distributed control system replacement, scrubber outlet modifications and rebuilds, and induced draft fan drive replacement. These modifications have decreased emissions and increased plant efficiency. Importantly for this context, they have also increased the plant's capacity by 140 MW, resulting in a 68 MW increase in available capacity for LADWP.[19]

3. <u>Navajo Generating Station</u>

The Navajo Generating Station completed the installation of scrubbers to remove SOx in all three units of the plant and began to install low-NOx burners to reduce NOx emissions starting with Unit 3 in 2009. Stringent NOx emissions control requirement by the federal government may require Navajo Generating Station to install Selective Catalytic Reduction, which could cost a total of $600 million, or $127 million for LADWP.[20]

The investments described above are just a few examples of ongoing capital investments in non-deemed compliant facilities that California POUs have made after the implementation of SB 1368 and the CEC's EPS regulations. New ownership investments are expressly prohibited by the CEC's regulations, but there is little if any information available to review these procurements. As POUs continue to face significant capital investments at coal-fired generation units due to the aging of the coal fleet as well as new and upcoming regulations, a lack of CEC oversight and enforcement could result in multiple violations of the EPS.

[17] SCPPA San Juan Unit 3 Status Report, December 2008 (Attachment 5).

[18] SCPPA, "Independent Auditor's Report and Combined Financial Statements," 2009, at p.4 available at: http://www.scppa.org/Downloads/Annual%20Report/scppa2008_FINAL_FS.pdf.

[19] LADWP, "2010 Power Integrated Resource Plan: Final," p.F-5 (Dec. 15 2010) available at: http://www.ladwp.com/ladwp/cms/ladwp014239.pdf

[20] Id. at p. F-5-6.

B. Planned Investments at Existing Coal Plants Constitute "New Ownership Investments"

The CEC must act quickly to provide guidance to POUs and prevent further investments in coal-fired generating units that may violate California law. POUs face substantial capital investment decisions in the very near term. Based on limited publicly available information, the non-EPS compliant plants have already undergone or are considering significant alterations, expansions and investments involving potential long-term investments from California POUs.

For example, proposed regulations may change the way coal combustion residues are handled and stored at IPP and Navajo generating station.[21] If implemented, the rules would require the phase-out of wet handling systems and surface impoundments of bottom ash and the subsequent permitting and installation of lining under fly ash landfills. The facilities would have to conduct additional groundwater monitoring, and provide closure and post-closure care of the surface impoundments and landfills. California POUs account for 75% of the purchased generation of the Intermountain Power Project in Utah, and LADWP has a contract to receive 21.2% of the Navajo Generating Station output through 2019.[22] These coal plants have faced and will continue to face ongoing capital investment requirements for environmental compliance measures that go far beyond routine maintenance expenditures. Continuing to invest in these plants exposes California consumers to financial risks associated with future compliance costs as well as future reliability risks in electricity supplies. SB 1368 expressly identified the reduction of these risks as a goal of the greenhouse gas EPS.[23]

The San Juan Generating Station provides perhaps the most substantial example of major capital investments that will be required in the near term. On August 5, 2011, EPA announced its final decision to require the installation of Best Available Retrofit Technology (BART) pollution controls on the San Juan Generating Station coal-fired powerplant near Farmington, New Mexico that would include installation of selective catalytic reduction (SCR) technology.[24] EPA estimated that the cost of compliance could reach $345 million,[25] and Public Service Company of New Mexico (PNM), which owns approximately half the plant, estimated the cost of compliance at over $750 million.[26] In either case, the retrofit costs to continue to operate the San Juan Generating Station would be substantial.

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[21] Id. at p.C-23.

[22] POU contract/ownership status from California Energy Commission, "An Assessment of Resources Adequacy and Resource Plans of Publicly Owned Utilities in California," staff report (Nov. 2009), available at: http://www.energy.ca.gov/2009publications/CEC-200-2009-019/CEC-200-2009-019.PDF

[23] SB 1368 (2006), Sections 1(i)-(j).

[24] EPA Final BART Rule, 40 CFR Part 52, EPA-R06-OAR-2010-0846.

[25] Id.

[26] PNM Press Release, August 5, 2011, available at www.pnm.com/news/2011/0805_epa_decision_bart.htm.

Several California POUs have ownership stakes in the San Juan Generating Station. SCPPA holds a 41.8% ownership interest in Unit 3 on behalf of five of its members: the City of Azusa; the City of Banning; the City of Colton; the City of Glendale; and the Imperial Irrigation District.[27] The MSR joint powers agency[28] owns a 28.7% interest in Unit 4, and the City of Anaheim has a separate 10% ownership interest in Unit 4. Together, these California public entities represent 24.51% of the common ownership interest in the San Juan Generating Station.[29] By contract, capital improvements at the San Juan Generating Station that exceed $5 million require an 82% majority vote of the co-owners.[30] Large capital investments such as the SCR controls therefore require at least one California owner to approve the expenditure. If the California owners do not vote to approve the capital investments in SCR, which is prohibited under California law, then the improvements should not go forward and California owners should not have to pay the costs of those improvements.[31]

Given the ownership structure of the San Juan Generating Station, it is within the discretion of the California owners to decide whether to invest hundreds of millions of dollars in the SCR controls required by EPA's BART determination, or whether to refrain from making new capital investments in the plant. The BART compliance costs are not routine maintenance expenses; the SCR controls are substantial investments designed to extend the legal and functional life of the San Juan Generating Station by bringing its old and dirty coal units into environmental compliance under current law. In accordance with SB 1368, the CEC's greenhouse gas EPS expressly prohibits this type of new ownership investment.[32]

The SCR costs described above are not the extent of future capital investments at San Juan. Other costs include controls to contain coal ash and scrubber waste, compliance with upcoming greenhouse gas cap-and-trade regulations, and potential remediation liability for groundwater contamination. These mounting environmental compliance costs will continue to accrue if California's POUs do not abide by the EPS and cease new ownership investments in these plants.

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[27] POU contract/ownership status from California Energy Commission, "An Assessment of Resources Adequacy and Resource Plans of Publicly Owned Utilities in California," staff report (Nov. 2009), available at: http://www.energy.ca.gov/2009publications/CEC-200-2009-019/CEC-200-2009-019.PDF.

[28] MSR is a joint powers agency consisting of the City of Santa Clara, the City of Redding, and the Modesto Irrigation District.

[29] Amended and Restated San Juan Project Participation Agreement, § 6.2.6, March 23, 2006 (Attachment 6).

[30] Amended and Restated San Juan Project Participation Agreement, § 18.4.2, March 23, 2006 (Attachment 6).

[31] To the extent that California POUs believe they would be forced by contract obligations to participate in SCR or other major investments even after voting against such investments, § 20 CCR 11 2913 requires those POUs to file a petition with the CEC requesting an exemption.

[32] Title 20, Cal. Code of Regs. §§ 2901(j) and 2902(b).

VII. Basis of CEC Authority (§ 1221(a)(4))

Public Utilities Code section 8341(c) requires the CEC to adopt regulations for the enforcement of SB 1368 with respect to a POU to establish a greenhouse gas emissions performance standard and to implement regulations for all long-term financial commitments in baseload generation made by POUs. The CEC adopted EPS regulations for POUs in October 2007.[33] Public Resources Code section 25213 provides that the CEC shall adopt rules and regulations as necessary. The CEC has the authority to initiate a rulemaking to amend its current regulations as requested by this petition because such amendment is necessary to clarify that existing law prohibits POUs from making capital investments in existing coal plants.

VIII. Petition Request 1: The CEC Should Develop Criteria to Determine Whether a Particular Investment in an Existing Coal Plant Constitutes a Covered Procurement

CEC action is necessary to provide guidance to the California POUs that retain an interest in coal plants to ensure their investment decisions comply with California law. The POUs have interpreted current regulations in a manner that allows them to effectively "self-regulate" by making unilateral determinations on the applicability of the EPS to any given investment. In order to ensure a more consistent and transparent process for evaluating potential investments at POU-owned coal plants, the CEC must develop clear criteria to evaluate whether an investment constitutes a covered procurement under the EPS. These criteria should be added to the existing implementation regulations and should supersede the existing structure for determining "covered procurements." It is incumbent upon the CEC to monitor and enforce compliance with the EPS if any POU makes unlawful capital investments in non-deemed compliant facilities.

IX. Petition Request 2: The CEC Should Amend the EPS Regulation to Require Monitoring and Approval of All Past and Proposed investments

The various investments that some POUs have made in coal plants since passage of the EPS, as well as the various investments being considered in light of EPA's pending regulations, lead us to conclude that the goal of SB 1368 -to phase out California investments in coal- will be undermined unless there is a more clear and transparent process to evaluate proposed investments. The CEC should amend its rule to require POUs to disclose and file information on any proposed investment in a non-EPS compliant facility. We have provided recommended language for such a reporting requirement in Attachment 1.

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[33] 20 CCR 11 § 2900 *et seq.*

X. CONCLUSION

For the forgoing reasons, we request the CEC:

1) Amend 20 CCR 11 §2907 as recommended in Appendix 1, below.

2) Develop clear criteria for the evaluation of investments at existing coal plants for compliance with the EPS.

Attachment 1

Reporting requirement recommended language:

(Criteria for evaluation of covered procurements should be added as a new section and is not included here.)

§2907 ~~Request for~~ Commission Evaluation of a ~~Prospective~~ Procurement <u>and Investments</u>

(a) A local publicly owned electric utility ~~may~~ <u>must, at least 90 days prior to any planned investment or procurement,</u> <u>or by January 1, 2012 for past investments, provide complete documentation for</u> ~~that~~ the Commission <u>to</u> evaluate ~~a prospective~~ procurement<u>s</u> <u>or investment at any facility emitting more than 1100 lbs/MWhr</u> ~~for any of the following:~~

~~(1) a determination as to whether a prospective procurement would extend the life of a power plant by 5 years;~~

~~(2) a determination as to whether a prospective procurement would constitute routine maintenance; or~~

~~(3) a determination as to whether a prospective procurement would be in compliance with the EPS.~~

(b) ~~A request for e~~ <u>E</u>valuation <u>of proposed and past investments</u> under this section shall be treated by the Commission as a request for investigation under Chapter 2, Article 4 of the Commission's regulations.

Attachment 2

Table: Out-of-State Coal Plants Owned by California POUs

Generating Station	Location	Nameplate Capacity (MW)[i]	Unit #	CA Owner	CA Owner's Share (%)[2ii]	Dependable Capacity (MW)	Expected End of Ownership
Boardman	Boardman, OR	601	1	SDG&E	15.0%	89	12/31/2013[iii]
				Turlock	8.5%	56	12/31/2018
Intermountain	Delta, UT	1640	1, 2	LADWP	48.6%[iv]	875	6/15/2027[v]
				Glendale	1.7%[vi]	38	6/15/2027
				Pasadena	4.4%[vii]	108	6/15/2027[viii]
				Burbank	3.4%[ix]	60	6/15/2027
				Riverside	7.6%	37	6/15/2027
				Anaheim	13.2%	236	6/15/2027
Navajo	Page, AZ	2406	1,2,3	LADWP	21.2%[x]	477	12/31/2019
Reid Gardner	Moapa, NV	295	4	CADWR	67.8%[xi]	200	2013
San Juan	San Juan, NM	555	3	SCCPA[xii]	41.8%	232	10/31/2030
		555	4	MSR[xiii]	28.7%	160	10/31/2030
				City of Anaheim	10.0%	50	10/31/2030

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[i] All capacity data from EIA's "Existing Electrical Generating Units by Energy Source, 2008" (preliminary data); available at: http://www.eia.doe.gov/cneaf/electricity/page/capacity/existingunitsbs2008.xls.

[ii] POU contract/ownership status from California Energy Commission, "An Assessment of Resources Adequacy and Resource Plans of Publicly Owned Utilities in California," staff report (Nov. 2009), available at: http://www.energy.ca.gov/2009publications/CEC-200-2009-019/CEC-200-2009-019.PDF.

[iii] Contract term from SDG&E SEC 10k filing for FY09

[iv] LADWP is entitled to receive 44.617% of the plant's capacity rating. LADWP has also purchased a 4% entitlement of the plant from Utah Power and Light. Both of these entitlements are valid until the 2027 contract termination date. In addition, LADWP can receive up to an additional 18.168% entitlement under the Excess Power Sales Agreement, however this percentage, or portions of this percentage, can be recalled from LADWP by other IPP participants, given certain defined advanced notices. The Intermountain Power Agency, which operates the plant, budgeted that LADWP would use 8.8% of this entitlement in 2009 for a total share of 53.5%. Over the last several years, some of the Utah municipal participants of the IPP have exercised their recall rights for IPP power. LADWP has been receiving approximately 300 MW from the Utah municipalities under an Excess Power Sales Contract since the start up of the project. In addition, the Utah municipalities have indicated an interest to construct a third IPP unit. LADWP has stated that it will not participate in the ownership of a new IPP unit 3. http://www.sao.state.ut.us/lgr/special/2010/10dbipag.pdf.

[v] LADWP's agreement began on February 1, 1983 and ends on June 15, 2027. There is an extension clause providing for continuation of entitlement shares of project output. The CEC reports the contract will expire earlier (12/31/2024), but all other sources – IPA reports; LADWP IRPs – note that all Intermountain contracts with CA POUs expire June 15, 2027. See, e.g, IPA 2009 annual report, available at:

http://www.ipautah.com/data/upfiles/pdfs/2008-2009%20Annual%20Report%20_final%20version_1.pdf; LADWP 2007 IRP, available at: http://www.ladwp.com/ladwp/cms/ladwp010273.pdf.

[vi] Glendale may obtain additional capacity under an Excess Power Sales Agreement and is estimated to have used an additional 0.2% in 2009, for a total share of 1.9%. See note 13, *supra*.

[vii] Pasadena may obtain additional capacity under an Excess Power Sales Agreement and is estimated to have used an additional 0.8% in 2009, for a total share of 5.2%. See note 13, *supra*.

[viii]Pasadena Water & Power (PWP) committed to reducing its purchases from Intermountain 35MW by 2016 in its 2009 IRP, available at: http://ww2.cityofpasadena.net/waterandpower/IRP/exhibits1and2.pdf PWP claims this reflects the amount of Intermountain capacity that may be feasible to sell under the existing contract arrangements.

[ix] Burbank may obtain an additional 0.8% under an Excess Power Sales Agreement and is estimated to have used an additional 0.4% in 2009, for a total share of 3.8%. See note 13, *supra*.

[x] On March 23, 1976, LADWP, Arizona Public Service Company (APS), Nevada Power Company (NPC), SRP, Tucson Electric Power Company (TEP) and U.S. Department of Interior executed the Navajo Project Co-Tenancy Agreement effecting the participation as co-owners, operation and maintenance of the Navajo Project until December 31, 2019. LADWP's entitlement of the Navajo Generating Station capability is 21.2%. The Navajo Operating Agent is SRP

[xi] Ownership data from "Management of the California State Water Project" Bulletin 132-05, Chapter 1, page 8, available at: http://www.swpao.water.ca.gov/publications/bulletin/05/Bulletin132-05.pdf.

[xii] SCPPA utilities with ownership interests: Azusa (14.7%), Banning (9.8%), Colton (14.7%), Glendale (9.8%), and Imperial Irrigation District (51%).
Contract term from SCPPA "Independent Auditor's Report and Combined Financial Statements," 2009, available at: http://www.scppa.org/Downloads/Annual%20Report/scppa2008_FINAL_FS.pdf.

[xiii] MSR is a joint powers agency consisting of the City of Santa Clara, the City of Redding, and the Modesto Irrigation District.

WEST ASSOCIATES

April 24, 2012

The Honorable Gina McCarthy
Assistant Administrator for Air and Radiation
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Dear Assistant Administrator McCarthy:

Thank you for meeting with me and representatives of the Western Energy Supply and Transmission (WEST) Associates on Thursday, April 12, 2012. WEST Associates is a coalition of cooperative, public- and investor-owned electric utilities[1] generating electric energy in eleven western states.

EPA's implementation of the Clean Air Act's Regional Haze program directly affects our Best Available Retrofit Technology (BART) – eligible plants, many of which are jointly owned by WEST Associates members. The Regional Haze program and the increased cost of electricity resulting from its implementation affect not only the states in which our plants are located, but also the states into which our electricity is sold.

EPA's proposed actions implementing the Regional Haze program raise a number of serious concerns. We discussed with you EPA's unrealistically low cost estimates for retrofit technology options, a more appropriate pace of achieving reasonable progress toward reductions in manmade visibility impairment, and the need for EPA to be more nimble in updating its models, particularly CALPUFF:

- In our discussion on costs, we noted our concern that EPA's Control Cost Manual is out-of-date. The data in this handbook, which was developed in 2002 to estimate the costs of installing controls, is now a decade old and no longer reflects current market costs of designing, engineering, and installing controls. We also asked you to correct the cost baseline used in EPA's cost estimates in the Manual. EPA should be using emissions from the plant as it exists today as the baseline when calculating the cost of any new, prospective emissions controls, excluding the emissions benefits from control technology already installed (such as Low NOx Burners) on a coal unit.

- Our discussion on modeling raised similar issues. While EPA has adopted the CALPUFF model as the preferred visibility modeling tool, it was developed by a group of professional scientists and engineers. These professionals continue to update and improve CALPUFF. EPA adopted and uses a version of CALPUFF that was introduced in 2007. The developers have since updated parts of CALPUFF in 2008, 2010, and 2011,

[1] WEST Associates Members include Arizona Electric Cooperative, Basin Electric Cooperative, NV Energy, PacifiCorp, Public Service of New Mexico, Salt River Project, Tri-State Generation and Transmission Association, Inc., Tucson Electric Power Co., and Colorado Springs Utilities.

but EPA has chosen not to use the most recent version of the model. We urge you to take steps to update the CALPUFF model and ensure that it is used in the agency's BART determinations.

- We also discussed how the Regional Haze program does not require that emission reductions occur on a date certain; rather, it is a long-term program designed to improve visibility in Class I areas with the national goal of achieving natural visibility conditions by 2064. The timing of emissions control projects is important; for example, they are often synched with opportunities for customer cost savings, such as scheduling projects to coincide with planned coal unit maintenance outages. Also, planning emission reductions over a longer period of time allows states and regulated entities to rely on coal unit retirements as part of a comprehensive emissions reduction strategy. If emissions reductions are front loaded (pre-2018), the remaining operating life of older coal units could be extended a decade or two in order to recoup the costs of expensive new controls required by a federal plan.

During our recent discussion, we particularly appreciated your interest in assuring that the regions administer the Regional Haze program consistently. We also appreciated your openness to looking into some of the problems we face, including the institutional issues of getting more accurate, realistic cost data; thinking about the cost baselines differently; and addressing the air quality modeling issues.

We committed to providing you with "real world" cost data as bid information is made available to WEST companies as they act on Regional Haze Implementation Plans. We will follow up with you on this information as soon as practicable.

In conclusion, I want to restate our appreciation for the time you spent with us and your openness to continuing to work with us on implementation of the Regional Haze program. If you have any questions or need additional information, please do not hesitate to contact me at ebakken@tep.com or by telephone at (520) 918-8351. Thank you for your consideration.

Sincerely,

Erik Bakken, President of the Board
WEST Associates