STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED REVISIONS TO THE STATE IMPLEMENTATION PLAN FOR THE SAN JUAN GENERATING STATION BEST AVAILABLE RETROFIT TECHNOLOGY DETERMINATION

EIB NO. 13-02 (R)

NOTICE OF INTENT TO PRESENT TECHNICAL TESTIMONY ON BEHALF OF PUBLIC SERVICE COMPANY OF NEW MEXICO

Pursuant to 20.1.1.302 NMAC, Public Service Company of New Mexico ("PNM") submits its Notice of Intent to Present Technical Testimony ("Notice") in the above-proceeding.

1. **The person for whom the witnesses will testify:**

Public Service Company of New Mexico.

2. **The name and qualification of each technical witness:**

   a. Ronald N. Darnell, Senior Vice President, Public Policy, for PNM. Mr. Darnell's statement of qualifications is attached as PNM Exhibit RND-1 to his pre-filed Direct Testimony.

   b. Chris M. Olson, Vice President, Generation, for PNM. Mr. Olson's statement of qualifications is attached as PNM Exhibit CMO-1 to his pre-filed Direct Testimony.

   c. Black & Veatch Corporation (Kyle J. Lucas and Diane M. Fischer). The statements of qualifications for Mr. Lucas and Ms. Fischer are attached as PNM Exhibit BV-1 and PNM Exhibit BV-2 to the pre-filed Direct Testimony of Black & Veatch.

d. Sargent & Lundy LLC (Dr. Rajendra Gaikwad). A statement of qualifications for Dr. Gaikwad is attached as PNM Exhibit SL-1 to the pre-filed Direct Testimony of Sargent & Lundy.

3. Location at Which the Witnesses will Present Testimony

Each of the foregoing witnesses will present their respective testimony at the hearing location in Farmington, New Mexico.

4. Summary and Estimated Duration of Testimony.

The full texts of the PNM witnesses' pre-filed Direct Testimony are attached to this Notice in the exhibits described more fully below. It is anticipated that each witness will provide introductory comments regarding their respective testimony of approximately 20 minutes in duration and will thereafter be subject to questions by interested parties and the Board.

5. Text of Recommended Modifications to the Proposed Regulatory Change.

PNM supports the regulatory change as proposed by the Petitioner New Mexico Environment Department.

6. List and Description of Exhibits.

PNM will move the admission of the following attached exhibits:

a. **PNM Exhibit A** – Direct Testimony of Ronald N. Darnell including the exhibits attached thereto as PNM Exhibit RND-1 (Statement of Qualifications) and Exhibit RND-2 (Agreement in Principle dated February 15, 2013).

b. **PNM Exhibit B** – Direct Testimony of Chris M. Olson including the exhibit attached thereto as PNM Exhibit CMO-1 (Statement of Qualifications).

c. **PNM Exhibit C** – Direct Testimony of Black & Veatch Corporation (Kyle J. Lucas and Diane M. Fischer) including the exhibits attached thereto as PNM

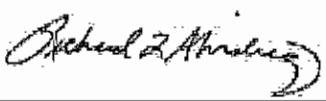
Exhibit BV-1 (Lucas Statement of Qualifications) and PNM Exhibit BV-2 (Fischer Statement of Qualifications)

d. **PNM Exhibit D** – Direct Testimony of Sargent & Lundy, LLC. (Dr. Rajendra Gaikwad) including the exhibit attached thereto as PNM Exhibit SL-1 (Gaikwad Statement of Qualifications).

7. Reservation of Rights.

PNM reserves the right to call any person to testify, and to present any exhibit, in response to any other notice of intent or public comment filed or submitted in this proceeding. PNM further reserves the right to refer to any testimony or exhibit offered in the proceeding by any other interested person.

Respectfully submitted,



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CERTIFICATE OF SERVICE

I certify that a true and correct copy of the foregoing Notice was filed with the New Mexico Environmental Improvement Board this 16th day of August 2013 and that copies of the foregoing were mailed on the same date to:

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Assistant Attorney General
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Attorney for Petitioner

New Mexico Environmental Improvement Board
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Santa Fe, NM 87594
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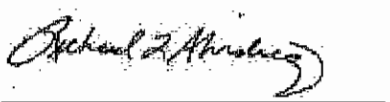

Richard L. Alvidrez

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STATE OF NEW MEXICO

ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED REVISIONS TO THE STATE IMPLEMENTATION PLAN FOR THE SAN JUAN GENERATING STATION BEST AVAILABLE RETROFIT TECHNOLOGY DETERMINATION	)))))	NMEIB No. 13-02 (R)

DIRECT TESTIMONY OF MR. RONALD N. DARNELL SUBMITTED ON BEHALF OF PUBLIC SERVICE COMPANY OF NEW MEXICO IN SUPPORT OF PETITION FOR REGULATORY CHANGE

PNM EXHIBIT A

I. INTRODUCTION AND PURPOSE OF TESTIMONY

My name is Ronald N. Darnell and I am Senior Vice President of Public Policy. In my position I am responsible for regulatory and government affairs, corporate communications and marketing, and community relations and stakeholder engagement. A summary of my qualification is attached as PNM Exhibit RND-1.

Public Service Company of New Mexico ("PNM") is submitting technical testimony in this proceeding to support the revised Regional Haze State Implementation Plan ("Revised SIP"), including the revised Best Available Retrofit Technology ("BART") determination for emissions of nitrogen oxides ("NOx") for the San Juan Generating Station ("San Juan"), proposed by the New Mexico Environment Department ("NMED"). As the operator and part owner of San Juan, PNM has a significant interest in this proceeding. PNM strongly supports the Revised SIP because it fully complies with the federal Clean Air Act ("CAA") Regional Haze requirements and it results in a lower cost than the Federal Implementation Plan ("FIP") issued by the U.S. Environmental Protection Agency ("EPA"). In addition, the Revised SIP provides comprehensive environmental benefits beyond those that would be realized under the FIP and better positions the plant for future environmental regulations.

The NMED's petition for approval of the Revised SIP is before the New Mexico Environmental Improvement Board ("Board" or "NMEIB") as a result of an agreement in principle embodied in a Term Sheet dated February 15, 2013 ("Term Sheet") among PNM, NMED and EPA. The Term Sheet provides the substance, process and timeline for an agreement that, if fully implemented, should result in, among other things, an EPA-approved Regional Haze SIP and an EPA-approved Interstate Transport SIP for New Mexico, with a less costly and more environmentally beneficial BART determination for San Juan. Under the provisions of the Term Sheet, if the NMEIB adopts

the Revised SIP and EPA approves the Revised SIP, then EPA will withdraw its FIP. The approval of the Revised SIP by the NMEIB is essential for this outcome. While the Term Sheet includes several elements which are provided for context and the Board's information, the Board's role is to consider and take action on the NMED's proposed Revised SIP. PNM appreciates the NMEIB's careful and thoughtful consideration of the issues in this proceeding and the benefits to New Mexico and the environment that will result from the adoption of the Revised SIP.

The primary purposes of my testimony, in order of presentation, are to: (a) introduce the other PNM witnesses in this case who are providing technical testimony and to briefly describe the subject matter of their respective testimonies; (b) further inform the NMEIB about PNM and the customers it serves; (c) provide useful background and context for Revised SIP and its submission to the Board for consideration and approval; and (d) affirm PNM's support for the Revised SIP and explain the associated benefits to PNM's customers and the environment under the Revised SIP.

II. PNM TECHNICAL WITNESSES

PNM is presenting testimony from four witnesses in this proceeding, including me. Chris Olson, PNM's Vice President, Generation, will provide a general description of San Juan, detailing its current ownership structure. Mr. Olson will also address the existing and proposed air emissions controls at San Juan and the economic impacts from San Juan's operations and the associated San Juan Coal Mine.

Black & Veatch Corporation ("B&V"), a preeminent engineering, design and consulting firm, performed the BART analysis for PNM that was submitted to the NMED to support the Revised

SIP. B&V will provide background concerning the CAA Regional Haze Rule and a description of the analysis that must be utilized in performing any BART determination. B&V will also detail the significant visibility improvements and other environmental benefits under the Revised SIP. In addition, B&V addresses certain comments submitted to the NMED by the National Park Service ("NPS") by letter dated July 24, 2013 ("NPS Comments").

Sargent & Lundy, LLC ("S&L") is a leading global engineering, design and consulting company focused exclusively on the power generation industry. S&L will provides an analysis of the costs associated with air emission controls at San Juan with a particular focus on the very substantial costs associated with the installation of selective catalytic reduction ("SCR") technology as mandated under the FIP. The cost to install SCR at San Juan has been an area of disagreement with respect to the NOx BART determination for San Juan. In keeping with the EPA's strong preference, S&L utilized EPA's OAQPS Air Pollution Control Cost Control Manual ("Cost Control Manual") to the greatest extent possible in its cost analysis. In those instances where S&L had to depart from the Cost Control Manual, it provides a detailed and thorough discussion and support for the departure. S&L also presents its analysis of the cost effectiveness of the various NOx control technologies considered in the BART analysis. The S&L testimony also addresses the SCR cost estimates raised in the NPS Comments.

III. INTRODUCTION TO PNM

PNM is a public utility that is dedicated to providing reliable, safe and cost-effective electric service to its customers. It was incorporated in New Mexico in 1917 and since that time has grown with the state to meet the energy needs of its customers. The company provides electric generation, transmission and distribution service to over 500,000 customers in New Mexico. Service to retail electric customers is subject to the jurisdiction of the New Mexico Public

Regulation Commission ("NMPRC"). The NMPRC is responsible for overseeing and authorizing investment decisions and for approving customer rates for public utilities operating in New Mexico. PNM is one of three investor-owned electric utility companies in the state. The others are El Paso Electric Company and Southwestern Public Service Company.

PNM employs over 1,500 employees in New Mexico. PNM's parent company, PNM Resources, Inc., is the only publicly traded company headquartered in New Mexico and is listed on the New York Stock Exchange.

IV. BACKGROUND AND CONTEXT FOR THE TERM SHEET

A. The Existing New Mexico SIPs

The NMEIB previously adopted a full Regional Haze SIP, including a NOx BART determination for San Juan, in June of 2011. At the same time, the NMEIB adopted a revised Interstate Transport SIP which incorporated the San Juan NOx BART determination for purposes of visibility protection under the Interstate Transport rule. Based upon the evidence presented in that proceeding, the NMEIB adopted a NOx emission limit of 0.23 lb/mmBtu to be achieved with the installation of selective non-catalytic reduction ("SNCR") technology on all four San Juan units. The 0.23 lb/mmBtu NOx emissions limit matched the presumptive limit under the EPA's Regional Haze guidelines.[1] In addition, as part of the full BART determination for San Juan, the NMEIB accepted the NMED's recommendation that the existing SO_2 rate of 0.18 lb/mmBtu used in the 2007 BART analysis be reduced to 0.15 lb/mmBtu for further visibility improvement. PNM did not oppose this reduction and has since modified its air permit to

[1] EPA NOx presumptive limit for subbituminous fuel as described in 40 CFR 51, Appendix Y to Part 51 - Guidelines for BART Determinations Under the Regional Haze Rule.

incorporate this reduced SO_2 emission limit. The Regional Haze SIP and the revised Interstate Transport SIP were submitted to the EPA for review and approval on July 5, 2011.

B. The Existing EPA FIP

While the NMEIB was considering the Regional Haze SIP and the revised Interstate Transport SIP, the EPA had undertaken its own rulemaking proceeding for the adoption of an Interstate Transport FIP for New Mexico and a NOx BART determination for San Juan. On August 5, 2011, EPA issued an Interstate Transport FIP and a BART NOx determination for San Juan. In the FIP, EPA disapproved a portion of the 2007 New Mexico Interstate Transport SIP that addressed the requirement in Section 110(a)(2)(D)(i)(II) of the CAA that emissions from New Mexico not interfere with measures required by other states to protect visibility. To correct this perceived deficiency, EPA established San Juan NOx and SO_2 emission limits that are intended to prevent such interferences. EPA determined that the NOx BART for San Juan is an emission limit of 0.05 lb/mmBtu achieved by using SCR on all four units. The EPA did not make a BART determination for San Juan with respect to particulate matter ("PM") or SO_2; however, EPA did require an SO_2 limit of 0.15 lb/mmBtu on all four boilers. EPA deferred action on other aspects of the New Mexico SIP submittals.[2]

C. The Legal Challenges to the FIP

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[2] On November 27, 2012, EPA published its approval of the New Mexico Regional Haze SIP revisions submitted on July 5, 2011 and December 1, 2003. EPA approved all the components of the State's submittals except the provisions related to the San Juan NOx BART. Included in the approval are the Western Backstop SO_2 Trading program and provisions covering emissions inventory, smoke management and open burning. EPA confirmed NMED's San Juan PM BART determination that the existing pulse jet fabric filters and existing PM emission limit of 0.015 lb/mmBtu satisfies BART. EPA has yet to take action on the San Juan NOx BART determination in the SIP submitted on July 5, 2011.

The EPA FIP requires the owners of San Juan to install SCR on all four units. PNM estimates the total cost to install SCRs on all four units to be between $824 million and $910 million based upon a request for bid issued by PNM for an SCR engineering, procurement and construction contractor and the bid responses received from four contractors. These costs would substantially increase the current cost of power produced by San Juan and would have a significant impact on electricity rates in the communities served by PNM. As discussed in Mr. Olson's testimony, these costs would be separate from, and in addition to, the more than $320 million the San Juan owners have already incurred in implementing a comprehensive set of emission control upgrades during 2006 through 2009. In addition, notwithstanding this significant investment, there would still be minimal perceptible improvement in visibility in federal Class I areas under the FIP as compared to the Revised SIP. Visibility protection is the singular goal under the EPA Regional Haze Rule.

For the foregoing reasons, New Mexico Governor Susana Martinez, the NMED, and PNM mounted various legal challenges to the FIP as it related to the San Juan BART determination. Separate Petitions for Reconsideration of the FIP were filed with the EPA as part of the EPA's administrative process. However, EPA has not taken any action on the Petitions for Reconsideration.

In addition, Petitions for Review were filed with the U. S. Court of Appeals for the Tenth Circuit ("Tenth Circuit") challenging the FIP. WildEarth Guardians ("WEG"), an environmental advocacy group, filed a Petition for Review challenging the five-year compliance deadline under the FIP and asserted that the appropriate compliance period should be reduced to three years. Governor Martinez, the NMED, and PNM filed separate Petitions for Review seeking to overturn the FIP. The Petitions for Review were consolidated by the Tenth Circuit for purposes

of briefing and oral argument. These petitions have now been fully briefed and oral argument was conducted on October 22, 2012. However, as discussed below, the Tenth Circuit has not handed down any decision on the merits of the Petitions for Review as the parties are engaged in pending mediation ordered by the Court.

D. Negotiations For a FIP Alternative

In the spring of 2012, during the pendency of the legal challenges to the FIP, Governor Martinez sent a letter to EPA requesting a stay of the FIP to allow the parties to the Tenth Circuit proceedings and other stakeholders to explore viable alternatives to the FIP that would be in both the environmental and economic best interests of New Mexico. In response, on July 15, 2012, the EPA issued an administrative stay of the FIP for ninety days to allow stakeholders to confer about potential alternatives to the FIP. However, the September 21, 2016 compliance deadline for installation of SCR on all four San Juan units remained in effect.

The NMED convened a series of stakeholder meetings in August 2012 that included representatives from WEG, Sierra Club, New Energy Economy, Dine CARE, San Juan Citizens Alliance, National Parks Conservation Alliance, the Navajo Nation, the City of Farmington, San Juan County, the National Park Service and PNM. The NMED also conducted a public meeting in Farmington, New Mexico, at which EPA representatives appeared, to solicit input from the general public on potential alternatives to the FIP. Similar public meetings were conducted on the Navajo Nation.

Governor Martinez was instrumental in getting the parties and stakeholders to the table to explore various alternatives to the FIP. PNM is also very appreciative of the attention to this process that the full New Mexico Congressional delegation provided as well as the efforts of

President Ben Shelly of the Navajo Nation. Another important stakeholder group is comprised of the eight other owners of San Juan, all of whom have a significant interest in the resolution of the San Juan BART determination.

The NMED used information from the stakeholder process to formulate a proposal for a revised SIP. On October 12, 2012, EPA issued an additional 45 day extension of the earlier administrative stay of the FIP to allow time for any continued discussions. However, the final compliance date of September 21, 2016 remained unchanged and in effect.[3] In October 2012, NMED issued a proposed outline for a revised Regional Haze SIP, supported by PNM that would entail the closure of San Juan Units 1 and 2, the two smaller of the four San Juan units. EPA, however, did not agree to the initial NMED proposal.

PNM continued discussions with the Governor's Office, NMED and EPA. These negotiations culminated in the execution of the Term Sheet, a copy of which is attached as PNM Exhibit RND-2. The Term Sheet includes many of the concepts discussed during the NMED stakeholder meetings and represents a revised San Juan BART determination based on new information, including the retirement of Units 2 and 3.

As a result of status reports filed with the Tenth Circuit, the Court directed the parties to the pending legal challenges to the FIP to mediation to seek resolution of the litigated issues. Although to date no global settlement of the litigated issues has resulted from the mediation, Governor Martinez, EPA, NMED and PNM remain committed to the process for resolution of the issues relating to a NOx BART determination for San Juan as outlined in the Term Sheet.

[3] As part of the Term Sheet, EPA has agreed to work with PNM and the NMED to make reasonable adjustments to the compliance deadline in the event the Revised SIP is ultimately not approved.

V. THE TERM SHEET AND ITS ASSOCIATED BENEFITS

A. The Term Sheet

The Term Sheet calls for NMED to develop and seek adoption of revised Regional Haze and Interstate Transport SIPs. The NMED has developed the revised SIPs which are presently before this NMEIB. In their most basic terms, the revised SIPs must provide for:

- Installation of SNCR technology on San Juan Units 1 and 4 within fifteen months of final EPA approval of the Revised SIP (but no later than January 31, 2016) with an average NOx emission rate of no greater than 0.23 lb/mmBTU on a daily rolling 30-day average basis.
- Various performance testing to confirm whether an even lower NOx emission rate than 0.23 lb/mmBtu might be achieved and then implemented on San Juan Units 1 and 4.
- Imposition of an SO_2 emission rate of 0.10 lb/mmBtu for San Juan Units 1 and 4.
- The retirement of San Juan Units 2 and 3 by December 31, 2017. (It is important to note that the joint ownership of Units 2 and 3 presents more complex ownership issues than the original plan involving the retirement of Units 1 and 2, which are solely owned by PNM and Tucson Electric Power Company).

The Term Sheet also calls for the construction of a natural gas combustion turbine to be sited at San Juan to partially replace retired Units 2 and 3. Detailed replacement power strategies will be finalized over the coming months to assure that power alternatives will be available to meet PNM's generation needs and ensure reliability. The proposed combustion unit and other replacement power options are outside the scope of this proceeding. At present, the NMEIB need only address the terms of the Revised SIP as proposed.

B. Emission Reductions and Environmental Benefits Under the Revised SIP

The Revised SIP will result in very significant reductions in overall air emissions from San Juan. With regard to NOx emissions, the installation of SNCR with an emission limit of 0.23 lb/mmBtu will decrease NOx emissions from the two units by 23%. Coupled with the retirement of Units 2 and 3, overall plant emissions of NOx will be reduced by 62%. In addition, NOx emissions may be further reduced based on the outcome of the NOx emissions studies discussed above. If the testing shows that additional NOx reductions are feasible, those reductions will be incorporated into the San Juan air permit in the form of reduced emission limits.

San Juan's SO_2 emissions limit will also be significantly reduced by 67%. The Revised SIP calls for a reduction in permitted SO_2 emissions from Units 1 and 4 to 0.10 lb/mmBtu from the existing limit of 0.15 lb/mmBtu. This represents a 33% reduction of SO_2 emissions from just these two units. With the retirement of Units 2 and 3, SO_2 emissions will be further reduced by 34%. The significant reductions in NOx and SO_2 translate into visibility improvement comparable to those under the FIP. As detailed in the testimony of B&V, there is a 0.5 deciview or less difference between the Revised SIP and the FIP at all the affected Class I areas. This difference is imperceptible as a change in one deciview is a change in visibility that is discernible to the human eye[4]. Importantly, the Revised SIP balances cost impacts while resulting in significant visibility improvements and other environmental benefits as discussed below.

The retirement of two units at San Juan brings with it not only improvements to visibility in Class I and other areas, but other very important environmental benefits. In addition to the reductions in NOx and SO_2 discussed above, all other air emissions, including greenhouse gases,

[4] EPA. "Visibility in Scenic Areas." National Air Quality Status and Trends. Web. 2008

will be reduced by approximately half. The reductions in greenhouse gas emissions better positions San Juan to comply with future anticipated federal greenhouse gas emissions regulations applicable to fossil fuel electric generating plants.

The retirement of two units will also reduce water consumption and the generation of coal combustion residuals ("CCRs"). Table 1 below provides a summary comparison of the reduction of overall air emissions, water consumption and CCRs generated during plant operations between the Revised SIP and the FIP.

Table 1. Reduction Comparison of San Juan Current Emissions, Water Use and CCRs Generation to Revised SIP and EPA FIP (%)

	NOx	SO_2	Particulate Matter	CO	VOC's	CO_2	Mercury (Hg)	Water Consumption	CCRs
Revised SIP	62%	67%	50%	44%	50%	50%	50%	53%	48%
FIP	83%	0	0	0	0	0	0	0	0

If the Revised SIP is adopted as proposed, NOx, SO_2 and CO emissions from San Juan will be reduced by 62%, 67% and 44% respectively, and emissions of PM, volatile organic compounds ("VOCs"), carbon dioxide ("CO_2") and hazardous air pollutants (including mercury) will be reduced by approximately 50%. Additional environmental benefits include an estimated 53% percent reduction in water usage and solid waste (e.g., CCRs including spent limestone) generation will be decreased by 50%. Vehicle emissions from trucking raw materials and waste around the site, and to and from the facility, will be reduced by 50%. Finally, fugitive dust emissions from the on-site hauling of raw materials and waste on paved and unpaved roads along

with fugitive dust emissions from conveying coal, the pulverizers, and duct leaks will be decreased from approximately 407 tpy to 204 tpy, again a 50% reduction.

The raw material usage under the current conditions, the 2011 SIP and the FIP are estimated to be roughly the same. As shown in Table 2, under the Revised SIP scenario raw material usage will be reduced by approximately 50 percent as compared to the current condition, 2011 SIP and FIP.

Table 2. Raw Material Usage Comparison Between Revised SIP and Current Usage, 2011 SIP and EPA FIP

RAW MATERIAL	REVISED SIP (TPY)	CURRENT, FIP, AND 2011 SIP SCENARIOS (TPY)
Limestone[1]	86,052	172,104
Activated Carbon[1]	130	261
Coal[2]	2,667,364	5,334,729
No. 2 Diesel Oil[2]	1,007,336	2,014,671
[1]Based on 2012 material usage data. [2]Based on 2011 material usage data.		

C. Summary of Benefits of the Revised SIP

The Revised SIP includes many benefits and achieves three significant goals: (1) it meets the legal and technical requirements of the Regional Haze Rule; (2) it is more cost effective than the FIP, and consequently, less expensive to PNM's customers; and (3) it provides substantial environmental benefits. The first goal, compliance with the Regional Haze rule, is the prerequisite for any alternative to the FIP. The Revised SIP meets the requirements of the Regional Haze regulations and BART guidelines. The second goal is also critical - to minimize

customer cost impacts. The third goal is achieved through the significant reductions in overall air emissions and the broader environmental benefits discussed above.

In addition to these goals, PNM has been mindful of the economic benefits that San Juan provides to the state and the Four Corners region, including the local Native American population. Some of the potential adverse economic impacts resulting from the retirement of two San Juan units will be mitigated by the installation of the SNCR controls at San Juan, which along with a new gas peaking plant and associated pipeline, is estimated to bring 350 person years of construction work to the area. Though not a formal part of the Term Sheet, but of great importance to New Mexico, PNM has also agreed not to implement any layoffs at San Juan as a result of the retirement of the two units. Any reduction in force resulting from the Revised SIP will be by means of attrition.

PNM is also making efforts to assist the local Native American population to prepare for the jobs that are important to the Four Corners economy, including jobs that will be required for the construction of the SNCR and the gas peaking plant. PNM, the Navajo Nation, San Juan College and the Navajo Technical University have entered into a Memorandum of Understanding under which PNM will fund a job training program for eligible members of the Navajo Nation up to $1,000,000 over five years starting in 2013. To augment these and other economic development efforts in the Four Corners region, PNM will also support the Four Corners Economic Development Corporation with a contribution of $50,000 per year for the next three years.

Finally, but also of significant import, the Revised SIP will maintain system reliability in the regional power grid. San Juan is classified as an important asset and is an integral part of the power supply in the Southwest. While the reduction in the power supply to the grid will be

significant due to the retirement of two San Juan units, the Revised SIP allows sufficient time for planning and coordination for any necessary replacement power.

VI. CONCLUSION

The Term Sheet and the associated Revised SIP represent a significant milestone in PNM's efforts to implement an alternative Regional Haze compliance plan that meets the requirements of the Regional Haze Rule, reduces the cost impact to our customers, and has broad, long term environmental benefits. The Revised SIP not only furthers the goal of improved visibility but provides additional environmental benefits that would not be realized under either the existing NM 2011 SIP or the EPA's FIP. If adopted, the Revised SIP positions New Mexico for an improved environmental future by reducing not only haze-forming emissions but also other pollutants and greenhouse gas emissions. The Revised SIP will also conserve water and reduce the generation of CCRs.

PNM supports the proposed Revised SIP as providing an effective and comprehensive way to achieve better visibility and provide significant overall environmental benefits while allowing PNM to maintain a diverse generation portfolio and minimizing the cost impact to customers. PNM respectfully requests that the NMEIB approve the Revised SIP as presented.

AFFIDAVIT OF RONALD N. DARNELL

STATE OF NEW MEXICO)
)
)
COUNTY OF BERNALILLO)

I, Ronald N. Darnell, the Senior Vice President, Public Policy, for Public Service Company of New Mexico, upon being duly sworn according to law under oath, deposes and states: I have read the foregoing testimony and it is true and accurate based on my own personal knowledge and belief.

Signed this 13 day of August 2013

Ronald N. Darnell

Subscribed and sworn to me this 13 day of August 2013.

Notary Public

My Commission Expires:

September 12, 2016

RONALD N. DARNELL

EDUCATIONAL AND PROFESSIONAL SUMMARY

Address: Public Service Company of New Mexico
Alvarado Square, MS-0920
Albuquerque, New Mexico 87158

Position: Senior Vice President of Public Policy, 2012 to Present
Vice President, Regulatory Affairs, 2008 - 2012

Previous Positions:

Xcel Energy, 2000-2008
Director, Regulatory Administration South, 2007-2008
* Responsible for regulatory policy, administration and pricing for Xcel-Colorado's retail and wholesale operations

Director, Pricing and Planning, 2000-2007
* Responsible for electric, gas and thermal regulatory pricing and load forecasting for regulated utility services in all states

New Century Energy, 1998-2000
Director, Electric Rates and Regulatory Services
* For utility operations in Wyoming, Colorado, New Mexico, Texas and under the jurisdiction of the Federal Energy Regulatory Commission, 1999-2000
* For utility operations in Wyoming and Colorado, 1998-1999

Public Service Company of Colorado, 1982 - 1998
Pricing Consultant, Marketing Department, 1997-1998
Unit Manager, Electric Rate Design and Regulatory Policy, 1994-1997
Supervisor, Revenue Requirements, 1989-1994
Senior Rate Accountant, 1988-1989
Rate Accountant, 1983-1988
Junior Rate Accountant, 1982-1983

Education:
California State University, 1981
Bachelor of Science in Business Administration – Accounting Emphasis

Testimony Presented before:
Federal Energy Regulatory Commission
Colorado Public Utility Commission
Wyoming Public Service Commission
New Mexico Public Regulation Commission
- Case No. 08-00273-UT
- Case No. 08-00305-UT
- Case No. 09-00260-UT
- Case No. 10-00037-UT

Term Sheet
Between the U.S. Environmental Protection Agency,
Public Service Company of New Mexico and the State of New Mexico

This term sheet reflects a tentative agreement on technical terms and an appended corresponding timeline for action intended to address pollution control requirements for the San Juan Generating Station under the Clean Air Act's requirements for regional haze and interstate transport for visibility. These terms have no binding effect and will only become binding if incorporated into a settlement agreement that receives all necessary EPA and Department of Justice approvals and complies with Section 113(g) of the Clean Air Act, as applicable.

1. The New Mexico Environment Department (NMED) will develop and seek adoption by the New Mexico Environmental Improvement Board ("NM EIB") of a State Implementation Plan (SIP) revision. If the NM EIB approves the SIP revision after following all applicable procedural requirements including notice and a public hearing, the Governor of the State of New Mexico or her designee will submit the SIP revision to EPA for approval with supporting administrative and technical information and visibility modeling. The SIP revision will include the following elements:

    a. Rulemaking addressing a NOx Best Available Retrofit Technology (BART) determination and enforceable emissions limits for SO_2.

    b. A five-factor BART analysis in accordance with the BART Guidelines, and other EPA guidance, as applicable, including documentation relied upon in making the BART determination. The use of confidential business information will be minimized to the extent practical in making the analysis.

    c. New Mexico's rulemaking will require that fifteen (15) months after EPA final approval of the Revised SIP, no earlier than January 31, 2016, Public Service Company of New Mexico (PNM) will complete installation of selective non-catalytic reduction (SNCR) technology on SJGS Unit 1 and 4 and aehieve an average nitrogen oxide (NOx) emission rate for Units 1 and 4 of no greater than 0.23 lb/MMBtu on a daily rolling 30-day average basis. Within 30 days after this "Term Sheet" is signed, PNM will submit a project schedule to the State and EPA that demonstrates the critical milestones for meeting the January 31, 2016, installation completion date. The dates that follow with an asterisk (*) in paragraph d. will be revised accordingly if the installation date extends past January 31, 2016 due to delay in EPA's SIP approval.

    d.

        i. Testing Program. PNM will commence a program of testing and evaluation, after the installation of the SNCRs. The Testing Program consisting of SNCR Performance Testing, Fuel Performance Testing, and Long-Term Performance Evaluation is to be completed no later than January 31, 2017*, unless the Long-Term Performance Evaluation is delayed per the language in paragraph 1.d.iv.

ii. SNCR Performance Testing will be conducted to develop a targeted ammonia/urea injection rate range at various load levels without exceeding a to-be-agreed-upon preliminary slip limit of between 5 and 10 ppm, with the goal of minimizing NOx emissions. PNM shall provide the results of the performance tests, recommended final slip limit, and target ammonia/urea injection rates to NMED and EPA by April 1, 2016*. PNM will allow up to April 30, 2016* for the agencies to either concur with PNM's slip limit recommendation or to concur on a different slip limit that PNM will comply with for Units 1 and 4.

iii. PNM will conduct Fuel Performance Testing (in conjunction with the SNCR Performance Testing) of its pre-treated coal technology, so long as it has not been previously determined to result in any detrimental effect to SJGS Units 1 and 4 or their operation, with the objective of further reducing NOx emissions. If the Fuel Performance Testing demonstrates that it does not: (i) measurably increase NOx emissions, or (ii) adversely impact overall unit operations, PNM shall also use such pre-treated coal for the 9-month Long-Term Performance Evaluation Period described below. PNM will also use pre-treated coal on units 2 and 3 when used on units 1 and 4.

iv. Long-Term Performance Evaluation Period. PNM will begin collecting NOx emission and ammonia/urea injection rate data from Units 1 and 4 on a daily rolling 30-day average basis for nine continuous months beginning on May 1, 2016* and provide such data and any recommendations on the NOx emission limit to NMED and EPA by February 28, 2017* or no later than 28 days after completing the Long-Term Performance Evaluation Period. PNM may request more time if a slip limit is not agreed upon by April 30, 2016*. The Long-Term Performance Evaluation Period must include 60 days between June 1st and August 30th and 60 days between December 1st and February 28th. The Demonstrated Emission Rate will be the highest daily rolling 30-day average emission rate during the 9-month Long-Term Performance Evaluation Period (not including periods of malfunction or abnormal operating conditions) adjusted to three significant digits. If the Demonstrated Emission Rate is greater than or equal to 0.200 lb/MMBtu on a daily rolling 30-day average basis no adjustment to the NOx emission rate for units 1 and 4 will be made. If the Demonstrated Emission Rate is less than 0.200 lb/MMBtu on a daily rolling 30-day average basis PNM will apply for a permit modification by March 31, 2017* (or no later than 60 days after completing the Long-Term Performance Evaluation Period) to reduce the permitted emission rate by 60% of the difference between 0.23 lb/MMBtu and the Demonstrated Emission Rate, provided the revised emission rate does not adversely impact overall unit operations. The permit modification will include the agreed upon ammonia slip limit.

e. New Mexico's rulemaking will require that no later than six months from NM EIB adoption of SO_2 emission limit in the RH and Interstate Visibility Transport SIP revisions, PNM will comply with new sulfur dioxide ("SO_2") emission rates at Units 1 and 4 of 0.10 lb/MMBtu on a daily rolling 30-day average basis.

f. New Mexico's rulemaking will require that PNM diligently seek all necessary regulatory approvals to allow for retirement of SJGS Units 2 and 3 by December 31, 2017. New Mexico's rulemaking will require PNM to retire SJGS Units 2 and 3 by December 31, 2017.

2. NMED and EPA intend that the Regional Haze and Interstate Transport SIP revisions as adopted and submitted to EPA will, if approved by EPA, lead to EPA action withdrawing the federal implementation plan for SJGS. Nothing in the Regional Haze and Interstate Transport SIP revisions as adopted and submitted to EPA by New Mexico shall relieve SJGS from its obligations to comply with all applicable federal, state, and local laws and regulations, including laws, regulations, and compliance deadlines that become applicable after the date of any revisions to New Mexico's Regional Haze SIP that may be approved by EPA.

3. NMED also will develop and propose as part of the revised BART determination for PNM, a revision to the Visibility Interstate Transport SIP for NOx and SO_2. NMED's Visibility Interstate Transport SIP revision will require enforceable emissions limits for NOx and SO_2 consistent with the emission limits established in the Regional Haze SIP submission in accordance with item 1.

4. PNM agrees that the natural gas combustion turbine(s) to be sited at the San Juan Generating Station to partially replace the retired Unit 2 and Unit 3 coal capacity will undergo BACT analysis and control even if not subject to major source PSD, with the goal of minimizing the visibility impact of emissions of NOx. PNM agrees that the aggregate annual NOx emissions from any such on site replacement power shall not exceed 75 tons.

Signature Page for Term Sheet between the U.S. Environmental Protection Agency, Public Service Company of New Mexico, and the State of New Mexico.

FOR PUBLIC SERVICE COMPANY OF NEW MEXICO:

Dated: February 15, 2013

Patricia K. Collawn
President and CEO
Public Service Company of New Mexico

Signature Page for Term Sheet between the U.S. Environmental Protection Agency, Public Service Company of New Mexico, and the State of New Mexico.

FOR THE STATE OF NEW MEXICO:

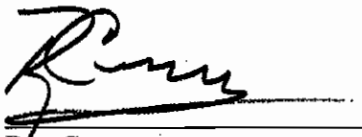
Dated: Feb. 15, 2013

F. David Martin
Secretary
New Mexico Environment Department

Signature Page for Term Sheet between the U.S. Environmental Protection Agency, Public Service Company of New Mexico, and the State of New Mexico.

FOR THE U.S ENVIRONMENTAL PROTECTION AGENCY:

Dated: February 15, 2013



Ron Curry
Regional Administrator
U.S. Environmental Protection Agency, Region 6

TERM SHEET ATTACHMENT

Timeline

February 15, 2013	EPA Comfort Letter
February 22, 2013	Letter from NMED requesting that EPA not take action on the current SIP.
March 2013	PNM submits new BART analysis to NMED
March 2013	NMED begins work on revised SIP pursuant to the "Term Sheet"
May/June 2013	Request hearing before the EIB and start public comment period
September 2013	Revised SIP presented to EIB
Within 30 Days of preceding event	Revised SIP submitted to EPA
Within 60 Days of preceding event	Completeness Determination (EPA can now determine if additional discussion concerning FIP Compliance Dates is warranted)
Within 135 Days of preceding event	EPA proposes action on Revised SIP
Within 150 Days of preceding event	EPA final aetion on Proposed SIP
Within 30 Days of preceding event	EPA/NMED discussion concerning FIP Compliance Dates (if necessary)

STATE OF NEW MEXICO

ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED REVISIONS TO THE STATE IMPLEMENTATION PLAN FOR THE SAN JUAN GENERATING STATION BEST AVAILABLE RETROFIT TECHNOLOGY DETERMINATION	)))))	NMEIB No. 13-02 (R)

DIRECT TESTIMONY OF CHRIS M. OLSON
SUBMITTED ON BEHALF OF PUBLIC SERVICE COMPANY OF NEW MEXICO
IN SUPPORT OF PETITION FOR REGULATORY CHANGE

PNM EXHIBIT "B"

I. INTRODUCTION

My name is Chris M. Olson. I am the Vice President, Generation, for Public Service Company of New Mexico ("PNM" or the "Company"). My address is 2401 Aztec Road NE, Albuquerque, New Mexico 87107. As Vice President, Generation, I am responsible for the strategic direction and operation of PNM's generating resources to ensure that they continue to provide safe, reliable and efficient electricity generation to customers within PNM's service territory. The functions I oversee include generation operations, maintenance, engineering, construction, fuel and power procurement and other services related to PNM's generation fleet for PNM's New Mexico customers. A statement of my qualifications is attached as PNM Exhibit CMO-1.

II. PURPOSE OF MY TESTIMONY

My testimony will provide the NMEIB with an overview of PNM's generation and a detailed description of the San Juan Generating Station ("San Juan") and its importance in providing safe and reliable electricity to PNM's customers and customers served by the other San Juan owners. I will also address the existing and proposed air emission control equipment for San Juan. In addition, I will describe San Juan's ownership structure and the favorable economic impacts the operation of San Juan provides New Mexico and surrounding community.

III. PNM GENERATION PORTFOLIO

PNM owns, leases, or purchases a diverse portfolio of 2,400 megawatts ("MW") of electric generation and relies upon that portfolio to cost-effectively supply the electricity needs of its New Mexico customers. Table I below shows PNM's existing generation resources, including San Juan, which currently comprises about a third of PNM's generation capacity and over half of

PNM's annual energy generation. San Juan is an important asset within PNM's generation portfolio and provides a significant economic benefit to the Four Corners Region.

Table 1. PNM Generation Portfolio

Generating Plant	Fuel Type	PNM Ownership	PNM Share of Net Capacity (MW's)	In-Service Date	Operating Agent
San Juan	Coal	46.3 %	783	1973-1982	PNM
Palo Verde 1 & 2	Nuclear	10.2 %	268	1985-1986	APS
Four Corners 4 & 5	Coal	13 %	200	1969-1970	APS
Afton	Natural Gas	100 %	230	2007	PNM
Reeves	Natural Gas	100 %	154	1958-1962	PNM
Lordsburg	Natural Gas	100 %	80	2002	PNM
Luna Energy Facility	Natural Gas	33.3 %	185	2006	PNM
Delta (PPA)[1][2]	Natural Gas	N/A	132	2001	Delta Person LLC
Valencia (PPA)	Natural Gas	N/A	145	2008	SWG Valencia Power LLC
NMWEC (PPA)	Wind	N/A	200	2003	FPL
PV Solar Sites[3]	Solar	100%	22	2011	PNM
TOTAL			**2,400**		

Note: APS- Arizona Public Service; SWG- Southwest Generation; and FPL- Florida Power &Light.

[1] PPA- Purchase Power Agreement (PPA).
[2] In December 2012, PNM entered into an agreement with the owners of Delta under which PNM would purchase the entity that owns Delta. While that transaction has been approved by the New Mexico Public Regulation Commission, the closing of the sale has not yet occurred.
[3] An additional 20 MW of PV solar is under construction and will be on-line by the end of 2013.

IV. SAN JUAN GENERATING STATION

A. Description of San Juan and Capacity

San Juan is located in Waterflow, New Mexico, 15 miles west of Farmington. It is what is commonly known as a "mine mouth" plant and is located immediately adjacent to the San Juan Coal Mine which provides the necessary fuel for San Juan. The mine is operated by the San Juan Coal Company, an affiliate of BHP Billiton.

San Juan consists of four coal-fired units with 1683 net MW of electric generation capacity. Each unit consists of a pulverized coal, wall-fired, dry bottom boiler and generator set. San Juan Units 1 and 2 are equipped with Foster Wheeler subcritical, wall-fired boilers, whereas, Units 3 and 4 are equipped with Babcock & Wilcox subcritical, wall-fired boilers. The net generation capacity and in-service dates for each of the four units at San Juan are:

- Unit 1: 340 MW, on line in 1976
- Unit 2: 340 MW, on line in 1973
- Unit 3: 496 MW, on line in 1979
- Unit 4: 507 MW, on line in 1982

B. San Juan Ownership

San Juan is owned by a diverse group of entities. Two New Mexico municipal entities, the Incorporated County of Los Alamos and the City of Farmington, each own separate interests in San Juan Unit 4. Other governmental entities owning interests in San Juan include the City of Anaheim, California, M-S-R Public Power Agency, Utah Associated Municipal Power Systems, and the Southern California Public Power Authority. Tri-State Generation and Transmission

Association, Inc. is a part owner of Unit 3 and provides electric generation to New Mexico's rural electric cooperatives. Tucson Electric Power Company, an investor-owned utility, also has an interest in Units 1 and 2. Table 2 below shows the current ownership interests by unit at San Juan.

Table 2: San Juan Ownership Structure

OWNER	UNIT 1	UNIT 2	UNIT 3	UNIT 4
Current Ownership(1)	PNM 50% TEP 50%	PNM 50% TEP 50%	PNM 50% SCPPA 41.8% TSG&T 8.2%	PNM 38.5% MSR 28.8% COA 10% COF 8.5% UAMPS 7 % LAC 7.2%

(1)Ownership
PNM – Public Service of New Mexico
TEP – Tucson Electric Power
SCPPA – Southern California Public Power Authority
TSG&T – Tri-State G&T
MSR – MSR Public Power Agency
COA – City of Anaheim, CA
COF – City of Farmington, NM
UAMPS – Utah Associated Municipal Power System
LAC – Los Alamos County

With the adoption of the Revised SIP and the subsequent retirement of two units, the ownership of San Juan will change; however, the final ownership make-up has not yet been determined.

C. Customers Served

For 40 years, San Juan has provided reliable energy at a reasonable cost to consumers in New Mexico and much of the West. San Juan provides energy to more than 1 million New Mexico consumers, including over 500,000 PNM customers, 450,000 New Mexico rural electric cooperative customers, 44,000 City of Farmington customers and 8,500 Los Alamos County

customers. All told, the San Juan facility provides electricity to over two million customers that are served by its owners.

D. San Juan as a Source of Electricity for New Mexico and the Southwest

San Juan is an important resource serving the electricity needs of New Mexicans. San Juan has been a low-cost, reliable source of electricity for four decades. It is the second-lowest cost source of electricity in PNM's energy portfolio and a key reason for the relative affordability of PNM's rates. San Juan is PNM's primary source of baseload generation and PNM ownership share of Unit 3 represents its largest single resource. It provides necessary baseload generation for PNM which is essential to maintaining reliable electric service. San Juan and its related transmission facilities are also important to the western power grid.

E. Economic Impacts

i. Employment and benefit statistics

Not only is San Juan a low cost, reliable source of energy for consumers, it also has a significant economic impact on the Four Corners Region. Currently, approximately 400 area residents are employed at the plant with an annual payroll and benefits of $61.3 million. The average length of employment at San Juan is 13.6 years. The employees of San Juan are actively involved in the local community. PNM has donated nearly $2 million to the San Juan College School of Energy to support the college and its power plant-related education programs. PNM also funds eight scholarships offered through an endowment with the San Juan College Foundation. In addition, San Juan helps support local schools and non-profits.

San Juan Coal Company, the fuel supplier for San Juan, employs approximately 470 area residents with an annual payroll of $46.9 million. The workforces at San Juan and San Juan Coal Company are diverse and include very significant representation from the local Native American community – in fact, 24 percent of the San Juan employees and 45 percent of the San Juan Coal Company employees are Native American. In addition, the two largest contractors conducting work at San Juan employ approximately 75 percent Native Americans in their workforce. The power plant and related coal mine operations are especially important to the nearby Navajo Nation where unemployment has fluctuated between 40 percent and 45 percent in recent years.

Though not part of the Revised SIP, PNM has carefully considered the economic impact to the Four Corners area and the State in deciding to retire two units. To help mitigate the potential economic impact, PNM will:

- Construct, subject to approval by the New Mexico Public Regulation Commission, a 150 to 200 MW natural gas peaking plant at San Juan, creating approximately 350 person years of construction jobs[4],
- Not lay off any San Juan employees as a result of the two unit retirement -- any reduction in workforce occurring through attrition,
- Provide over $1 million for a job retraining program and economic development in the Four Corners area.

In July 2013, to formalize a $1 million commitment to the Navajo Nation, PNM signed a memorandum of understanding with the Navajo Nation that provides funding for workforce training at colleges in Crownpoint and Farmington. The money will be paid in $200,000

[4] 350 person years includes the SNCR project, the gas peaking plant, and the associated pipeline.

installments over five years. Under the terms of the agreement, members of the Navajo Nation can qualify for $1,000 to $2,000 funding per semester at Navajo Technical College and San Juan College of Energy. In addition, PNM will support the Four Corners Economic Development Corporation with a $150,000 contribution to be paid over the next three years.

ii. Contribution to Tax Base

San Juan is also very important to the local tax base. It pays more than $59 million each year in coal royalties and taxes to governments and tribes, and $6.7 million each year to San Juan County in property taxes. The plant spends an average of $44 million each year for materials and supplies and an additional $434 million in service contracts, including payments for removal of coal ash.

G. Pollution Controls

1. Environmental upgrade (2006 – 2009)

San Juan has always controlled emissions from the generating station. Prior to the 2006 – 2009 environmental upgrades, the facility used electrostatic precipitators (ESP) to control PM, the forced-oxidation scrubber to control SO_2 and low-NOx burners on Units 1, 3 and 4. In 2009, the owners of San Juan completed significant upgrades to the station's emissions controls that further reduced air pollutants. From 2006 through 2009, PNM and the other owners invested more than $320 million in the following state-of-the-art pollution control equipment for San Juan:

- Pulse-jet fabric filter baghouses ("baghouses") that filter all of the flue gas, removing PM and Hg;
- Activated carbon injection equipment that enhances Hg removal in the baghouses;
- Low-NOx combustion control equipment comprised of low-NOx burners, and overfire air ports, which reduces emissions of NOx, and
- Elimination of the flue gas bypass of the SO_2 scrubbing system and installation of a dibasic acid injection system that is used as needed to increase SO_2 removal.

Overall, these air pollution control technology upgrades have reduced NO_x emissions by 44%, SO_2 emissions by 71%, and PM emissions by 72% based on a comparison of the 2005 and 2010 actual emissions. Notably, San Juan is an industry leader in mercury emissions control, achieving a 99% removal rate. The effectiveness of this technology was considered by EPA in setting the new Mercury and Air Toxics Standard applicable to the entire industry with respect to mercury controls.

2. Recent emissions reductions and permit changes

In August of 2012, San Juan applied for and received a modification to its New Source Review ("NSR") permit. In the permit, San Juan voluntarily accepted a new SO_2 limit of 0.15 lb/mmBtu on all four units that reduced potential facility-wide SO_2 emissions by 17%. In addition, the permit allows for the installation of either selective catalytic reduction ("SCR") to achieve a NOx emission rate of 0.05 lb/mmBtu on all four units under the EPA FIP or selective non-catalytic reduction ("SNCR") to achieve a NOx emission rate of 0.23 lb/mmBtu on the units under the NMED SIP. In addition, as required by an existing permit condition, San Juan incorporated

$PM_{2.5}$ condensable emissions into the permit. When added to the existing filterable $PM_{2.5}$ limit, the total $PM_{2.5}$ emission limit was set at 0.034 lb/mmBtu even though actual $PM_{2.5}$ emissions at San Juan did not change.

3. Future emissions reductions and permit changes

If the Revised SIP is approved, San Juan will see even further emission reductions by building upon the previously installed pollution control equipment at the facility. These upgrades will necessitate obtaining a permit revision that is consistent with the Revised SIP and will include the following:

- Installation of SNCR technology to meet a NOx emission limit of 0.23 lb/mmBtu on Units 1 and 4 no sooner than January 31, 2016. This will decrease permitted NOx emissions from the two remaining units by an additional 23%. Note that this limit may be further reduced based on the outcome of a NOx optimization study described in the February 15, 2013 Term Sheet among EPA, NMED and PNM ("Term Sheet") that will be performed after the SNCR is installed.
- SO_2 limit of 0.10 lb/mmBtu on Units 1 and 4 which reduces permitted SO_2 emissions by 33%. Under the Term Sheet, San Juan will be required to meet the lower SO_2 standard within 6 months of the adoption of the SO_2 emission limit in the Revised SIP by the New Mexico Environmental Improvement Board ("NMEIB").
- A requirement to permanently retire Units 2 and 3 by December 31, 2017. The retirement of the two units will further reduce station emissions, including greenhouse gases, from original levels by approximately 50% from current levels. It will also result in additional environmental benefits including reducing raw material use (i.e.,

coal, limestone, and activated carbon), and reducing CCRs (i.e., coal ash and scrubber sludge) by 50% and water usage by 53%.

In addition, though not part of this proceeding, PNM will submit an air permit application for a planned 150 to 200 MW simple-cycle natural gas turbine to be located at the San Juan facility. The increase in emissions as a result of the installation of the new turbine will be minimal compared to the emission reductions from the retirement of Units 2 and 3 as shown below:

Table 3: Comparison of Emissions from Units 2 and 3 to Typical Gas Turbine

Scenario	NO_x (tpy)	SO_2 (tpy)	PM (tpy)	CO (tpy)	VOC's (tpy)	CO_2 (tpy)
Unit 2 and 3 Combined Emissions	5,275	5,275	1,196	14,892	106	7,7385,166
Combustion Turbine Emissions	75.0	9.2	80.2	116.5	11.4	860,863

V. CONCLUSION

San Juan is and will remain an important asset to San Juan County, the State and the Navajo Nation as the facility continues to provide safe and reliable electricity to New Mexico and the region and brings significant economic benefit to the region. With the adoption of the Revised SIP, San Juan will significantly reduce overall air emissions, including greenhouse gas emissions. It will also reduce raw material and water use and allow reductions in the generation of CCRs. Taken together, these changes should position San Juan to be able to meet anticipated future environmental requirements, including greenhouse gas regulations relating to fossil fuel generation facilities.

The economic impacts related to the permanent retirement of two units will be mitigated by the construction and operation of a natural gas plant for replacement power, PNM's commitment to not lay off personnel at San Juan as a result of these retirements and the commitment to provide over $1 million for job retraining and economic development in the Four Corners area. PNM supports the petition for the adoption of the proposed Revised SIP and requests that the NMEIB approve the alternative.

This concludes my testimony.

AFFIDAVIT OF CHRIS M. OLSON

STATE OF NEW MEXICO)
)
)
COUNTY OF BERNALILLO)

I, Chris M. Olson, Vice Present, Generation, for Public Service Company of New Mexico, upon being duly sworn according to law under oath, deposes and states: I have read the foregoing testimony and it is true and accurate based on my own personal knowledge and belief.

Signed this 16 day of August 2013

Chris M. Olson

Subscribed and sworn to me this 16 day of August 2013.

Patricia A. Salls
Notary Public

My Commission Expires:
September 14, 2014

CHRIS M. OLSON

EDUCATIONAL AND PROFESSIONAL SUMMARY

Address: Public Service Company of New Mexico
Aztec Facility
2401 Aztec Road NE, Building A
Albuquerque, New Mexico 87107

Position: Vice President, PNM Generation, 2012 to Present

Previous Positions:

Corval Group, 2008 – 2012
Vice President, Power & Energy

DTE Energy, 2008
Director & Chief Engineer, Fossil Operations

Xcel Energy, 2000 – 2008
Plant Director, Sherburne County Generating Plant

Northern States Power, 1982 – 2008
General Manager, Regional Plants
Manager, NSPW Generation
Manager, Hydro Plants
Superintendent, A.S. King Plant
Engineer, Plant Engineering & Construction

Westinghouse Electric Corporation, 1980 – 1982
Field Service Engineer

Professional Affiliation:
Registered Engineer, State of Minnesota

Education:
University of Minnesota, Bachelor of Mechanical Engineering
University of Minnesota, Carlson School of Management, Minnesota Executive Program

STATE OF NEW MEXICO

ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED REVISIONS TO THE STATE IMPLEMENTATION PLAN FOR THE SAN JUAN GENERATING STATION BEST AVAILABLE RETROFIT TECHNOLOGY DETERMINATION	)))))	NMEIB No. 13-02 (R)

PRE-FILED TESTIMONY OF BLACK & VEATCH CORPORATION (KYLE LUCAS & DIANE M. FISCHER) SUBMITTED ON BEHALF OF PUBLIC SERVICE COMPANY OF NEW MEXICO

PNM EXHIBIT C

I. INTRODUCTION

Black & Veatch Corporation ("B&V") submits the following testimony on behalf of Public Service Company of New Mexico ("PNM") in this proceeding. The B&V personnel providing this testimony are Kyle J. Lucas, Project Manager, and Diane Fischer, Air Quality Control Engineering Manager. Copies of the statements of qualification for Mr. Lucas and Ms. Fischer are attached hereto as PNM Exhibit BV-1 and PNM Exhibit BV-2, respectively.

B&V is a leading global engineering, consulting, and construction company. Founded in 1915, B&V specializes in infrastructure development in energy, water, telecommunications, federal, management consulting and environmental markets. B&V is employee-owned, has more than 100 offices worldwide and is ranked on the Forbes listing of the "500 Largest Private Companies in the United States".

B&V was retained by PNM in 2006 to undertake an analysis of the San Juan Generating Station ("San Juan") for the purpose of analyzing the Best Available Retrofit Technology ("BART") requirements under the EPA's Regional Haze Rule. B&V has performed considerable work and analysis with respect to the San Juan BART determination. B&V performed the analysis, including the associated visibility modeling, for the revised Best Available Retrofit Technology ("BART") determination for the control of emissions of nitrogen oxides ("NOx") from San Juan, which underlies the revised state implementation plan ("Revised SIP") proposed by the New Mexico Environment Department ("NMED") in this proceeding.

The BART analysis and visibility modeling completed by Black & Veatch and submitted to NMED on April 1, 2013 is an addendum application document ("2013 BART Addendum") to the June 6, 2007 San Juan Generating Station BART Application and Analysis ("2007 BART Analysis"), which includes the control system capital costs prepared by Sargent & Lundy ("S&L"). The 2013 BART Addendum was prepared in accordance with the BART Guidelines, including the five-step BART analysis process consisting of:

- Step 1: Identify All Available Retrofit Control Technologies;
- Step 2: Eliminate Technically Infeasible Options;
- Step 3: Evaluate Control Effectiveness of Remaining Control Technologies;
- Step 4: Evaluate Impacts and Document the Results; and
- Step 5: Evaluate Visibility Impacts.

B&V performed a review of available NOx control technologies and confirmed the feasibility of these available control technologies for application at San Juan. The NOx control technology evaluation and control effectiveness was coordinated with S&L and has been detailed in the S&L the costs analysis is further detailed in the S&L testimony.

- Based on these findings, Black & Veatch updated its original CALPUFF visibility analysis by conducting an analysis using CALPUFF which followed EPA's modeling methodology as described in the 2011 technical support document and was confirmed by EPA in September and October 2012. The analysis evaluated three technology scenarios in addition to the Baseline. These scenarios included:
- Selective Catalytic Reduction ("SCR") – EPA Federal Implementation Plan (FIP).

- Selective Non-catalytic Reduction ("SNCR") – 2011 State Implementation Plan ("SIP").
- SNCR and a reduced SO_2 emission rate with Unit Retirement – Revised SIP.

As described in the following testimony, the 2013 BART Addendum, which is reflected in the Revised SIP, shows that the proposed NOx control strategy achieves visibility reductions in the Class I areas with no perceivable differences from the visibility reductions attained by the EPA FIP at a significantly lower cost.

In this testimony, B&V will address (a) the background and requirements under the federal regional haze protection rules; (b) the BART analysis applied to San Juan; (c) the visibility modeling under the BART analysis; and (d) the visibility improvement cost effectiveness of the various emission control scenarios evaluated under the BART analysis.

II. REGIONAL HAZE PROTECTION

A. Federal Regulatory History

The history of the Regional Haze Rule in New Mexico, and the related need for BART controls on San Juan Units 1-4, is multifaceted. The Regional Haze Rule was published on July 1, 1999 by EPA under the authority and requirements of sections 169A and 169B of the Clean Air Act ("CAA"). On July 6, 2005[1], EPA published updates to the final Regional Haze and BART Rule guidelines. The rule requires States to submit state implementation plans ("SIPs") addressing regional haze visibility impairment in 156 federally-protected parks and wilderness areas[2], and includes a requirement for installation and operation of BART for certain large stationary

[1] See, 70 Fed. Reg. 39104, July 6, 2005.
[2] See 40 CFR Part 81 for List of 156 Mandatory Class I Federal Areas

sources. States must address the BART requirements for all BART-eligible sources when they develop their regional haze SIPs.

BART eligibility for a source is defined by a combination of factors, such as source category, emissions of visibility impairing pollutants greater than 250 tons per year (tpy), an in-service date between August 7, 1962 and August 7, 1977, and reasonable anticipation that the source "contributes" to visibility impairment. The July 6, 2005 Regional Haze Rule included *Guidelines for BART Determinations Under the Regional Haze Rule* at Appendix Y to 40 CFR Part 51 (the "BART Guidelines") to assist states in determining appropriate BART emission limits for each BART-applicable source. Included in the regional haze guidelines is the requirement that BART-eligible sources implement emissions reduction alternatives or integrate controls for visibility impairing pollutants to meet the defined BART presumptive emission limits.

B. Key Terms Defined

1. Best Available Retrofit Technology ("BART")

BART is defined in the Regional Haze Rule[3] as "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, costs of compliance, energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to

[3] See 40 CFR Part 51 Regional Haze Regulations; Final Rule, July 1 , 1999

result from the use of such technology[4]." Thus, only control technologies that are technically feasible, cost-effective and do not have an unacceptable energy requirement or non-air quality environmental impact are eligible for consideration as BART[5]. Control technologies that are too expensive or not cost-effective are eliminated from the determination of BART.

2. Class I Areas

The EPA Regional Haze Rule is intended to protect visibility in federal Class I areas. "Class I areas" include national parks, wilderness areas, monuments, and other areas of special national and cultural significance. Federal Class I areas are afforded special environmental protection through enforcement of Class I increment values established in 40 CFR part 52.21. Additionally, Air Quality Related Values were developed to promote the protection of such areas from the environmental effects of a wide range of emission sources. The Federal Class I areas of interest in this regional haze BART analysis are as follows:

Table 1
Class I Areas

1. Mesa Verde National Park	9. West Elk Wilderness
2. Weminuche Wilderness	10. Arches National Park
3. San Pedro Parks Wilderness	11. Capitol Reef National Park
4. La Garita Wilderness	12. Pecos Wilderness
5. Canyonlands National Park	13. Wheeler Peak Wilderness
6. Black Canyon of the Gunnison National Park	14. Great Sand Dunes National Park
7. Bandelier National Monument	15. Maroon Bells-Snowmass Wilderness
8. Petrified Forest National Park	16. Grand Canyon National Park

[4] See, 40 CFR §51.301
[5] See, 70 FR 39104, July 6, 2005, at page 39164.

3. Visibility

Visibility refers to the clarity with which distant objects are perceived.[6] Visibility impairment is caused by light scattering and light absorption associated with particles and gases in the atmosphere.[7] Visibility impairment means any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions.[8] The terms "visibility impairment" and "impairment of visibility" include reduction in visual range and atmospheric discoloration.[9] Visibility impairment is often perceived as a general haze or a distinct plume.[10]

The three most common metrics used to describe visibility impairment are:

i. Extinction (b_{ext}) - Extinction is a measure of the fraction of light lost per unit length along a sight path due to scattering and absorption by gases and particles, expressed in inverse megameters (Mm-1). This metric is useful for representing the contribution of each aerosol species to visibility impairment and can be practically thought of as the units of light lost in a million meter distance.

ii. Visual Range (km) - Visual range is the greatest distance a large black object can be seen on the horizon, expressed in kilometers (km) or miles (mi).

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[6] "Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress" EPA-452/R-01-008. November 2001
[7] 40 CFR 51 Appendix W Section 6.2.1
[8] 40 CFR 51.301
[9] 42 U.S.C. §7491(g)(6)
[10] The Grand Canyon Visibility Transport Commission. *"Recommendations for Improving Western Vistas"*. June 10, 1996. *Website: http://www.wrapair.org/WRAP/reports/GCVTCFinal.PDF*

iii. Deciview (dv) - This is the metric used for tracking regional haze in the Regional Haze Rule. The deciview index was designed to be linear with respect to human perception of visibility. A one deciview change is approximately equivalent to a 10% change in extinction, whether visibility is good or poor. A one deciview change in visibility is generally considered to be the minimum change the average person can detect with the naked eye.

C. Summary of New Mexico Regional Haze Regulatory Actions

Section 110(a)(2) of the CAA requires revisions to the New Mexico SIP within three years of the promulgation or revision of any National Ambient Air Quality Standard ("NAAQS"). The SIP revision must address the four requirements specified in Section 110(a)(2)(D)(i), which are intended to mitigate adverse impacts to the NAAQS and visibility from interstate transport of pollutants. Thus, the SIP must prevent sources in the state from emitting pollutants in amounts which will:

- Contribute significantly to nonattainment of the NAAQS in other states;
- Interfere with maintenance of the NAAQS in other states;
- Interfere with provisions to prevent significant deterioration of air quality in other states;
- Interfere with efforts to protect visibility in other states.

In July 1997, EPA promulgated revisions to the NAAQS for ozone and fine particles ("$PM_{2.5}$") triggering a three-year deadline for SIP revisions to address the interstate transport provisions of Section 110(a)(2). This deadline was extended due in part to litigation over the 1997 NAAQS revisions.

On September 17, 2007, New Mexico submitted a SIP to EPA addressing each of the four elements, in accordance with the 2005 Guidance noted above. In 2010, EPA approved the first three elements of the SIP.

Regarding the fourth element on visibility, the September 17, 2007 SIP stated that New Mexico would submit an approvable SIP for regional haze by December 2007. However, New Mexico did not submit an approvable regional haze SIP by this date, and on January 15, 2009, EPA published a "Finding of Failure to Submit State Implementation Plans Required by the 1999 Regional Haze Rule."

New Mexico subsequently submitted a complete regional haze SIP, which was approved by the New Mexico Environmental Improvement Board ("NMEIB") on June 3, 2011. Governor Martinez submitted the approved SIP to EPA which was received on July 5, 2011. The 2011 SIP contained the State's BART determination for San Juan which would require the installation of SNCR technology on the four San Juan units to achieve a NOx emission rate of 0.23 lb/mmBtu on a 30-day rolling average.

On August 22, 2011, EPA disapproved the SIP with respect to the visibility element and issued a FIP to address the perceived deficiencies in the SIP including a BART determination for San Juan. Under the FIP, San Juan was required to install SCR technology on all four units to achieve a NOx emission limit of 0.05 lb/mmBtu on a 30-day rolling average. The FIP also imposed an SO_2 emission limit of 0.15 lb/mmBtu on a 30-day rolling average and a sulfuric acid emission limit of 2.6x10-4 lb/mmBtu on an hourly basis.

On November 27, 2012, EPA approved all components of the New Mexico SIP revisions submitted on July 5, 2011 and December 1, 2003, except for the NOx BART determination for San Juan. In addition EPA approved several SIP companion rules to the regional haze plan, including regulations for the Western Backstop Sulfur Dioxide Trading Program, for the inventorying of emissions, for smoke management, and open burning.

The FIP was subject to legal challenge lodged by PNM, NMED, Governor Martinez and WildEarth Guardians. As discussed by Mr. Ron Darnell, PNM, NMED and EPA entered into discussions to explore alternatives to the FIP. These discussions culminated in the previously described Term Sheet that was signed on February 15, 2013. The Term Sheet is the basis of this proposed SIP revision.

D. Submittals to NMED in Support of the BART Analysis

In June 2007, PNM submitted a timely BART analysis for San Juan Units 1, 2, 3 and 4 to NMED. These units were identified as BART–eligible sources by NMED because they cause visibility impairment in 16 Federal Class I areas that are within a 300 km radius, as identified in accordance with the Regional Haze and BART Rule guidelines that were published by EPA on July 6, 2005 (70 FR 39104). Since this submittal, PNM has responded to information requests from NMED and EPA, submitted information to support the possible control technology options and cost of these technologies, provided comments on EPA's Advanced Notice of Public Rulemaking proposal, and updated visibility analyses. The following highlights the significant submittals by PNM to support NMED's determination of San Juan's BART and the Regional Haze rulemaking. Additional information can be found on the NMED website.

- March 13, 2007 – San Juan Modeling Protocol Document
- June 6, 2007 – San Juan BART Application and Analysis
- April 13, 2007 - PNM BART Modeling Protocol and WRAP Modeling Protocol
- July 11, 2007 – SCR and SNCR Hybrid Cost Analyses
- August 23, 2007 – Updated Visibility Cost Effectiveness Data
- September 14, 2007 - PNM Response to NMED Questions on BART Analysis
- October 1, 2007 - PNM SCR Schematic
- November 5, 2007 – Refined Visibility Modeling and Results
- March 29, 2008 – PNM Discussion of OAQPS manual --EPA's Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, dated January 2002 ("Cost Manual")
- March 31, 2008 – Final BART Visibility Modeling Response to NMED
- May 30, 2008 – Final BART SNCR Analysis and Discussion of San Juan's Coal and BART Classification
- August 28, 2008 – Final Nalco-MOBOTEC Nitrogen Oxides and Final Particulate Matter BART Analyses
- November 11, 2008 – Response to NMED Regarding H_2SO_4 Emissions
- March 16, 2009 – Sulfate Removal Report
- October 27, 2009 – PNM Comments on the EPA Proposal Advanced Notice of Proposed Rulemaking[11]

[11] EPA-R09-OAR-2009-0598

- February 11, 2011 – Revised SNCR and Rate Impact Analyses
- April 1, 2013 – San Juan BART Addendum based upon February 12, 2013 Term Sheet agreement between EPA, NMED, and PNM, filed as Appendix D to New Mexico's Regional Haze SIP Under 40 CFR 51.309(g), May 21, 2013.

The material and data submitted to the NMED can be found in the following website link. http://www.nmenv.state.nm.us/aqb/reghaz/regional-haze_index.html

III. SAN JUAN BART ANALYSIS

A. Scenarios and Factors Considered in Determining BART

In the latest San Juan BART analysis, B&V considered the SCR and SNCR NO_x control technologies under the FIP, the 2011 SIP and the 2013 Revised SIP (which includes a two unit retirement) as available for retrofit at San Juan in the BART analysis. The factors we considered are:

Cost of compliance. The first factor considered when determining BART is the cost of compliance of each technically feasible control technology/method for the reduction of NO_x emissions. B&V analyzed the cost of compliance based on the requirements for implementing each of the considered technologies. The cost of compliance includes the total capital investment ("TCI") for each control technology when applied specifically to the San Juan units and the annual operating and maintenance ("O&M") costs associated with operating the control technology to achieve the required NO_x emission as defined in the BART analysis. B&V participated in the PNM San Juan BART analysis as the sole technology engineer until 2011.

Since this period, B&V has supported PNM's additional BART analysis in conjunction with Sargent & Lundy ("S&L").

Energy and non-air quality environmental impacts of compliance. As detailed in the testimony of PNM Witness S&L, the energy impacts were estimated for each control technology that consumes auxiliary energy during its operation. Only direct energy impacts for each control technology, such as the auxiliary power consumption of the control technology and the additional draft system power consumption to overcome the additional system resistance, were accounted for.

The auxiliary power consumption of the control technology was estimated on the basis of the typical power consumption of similar equipment of an equivalent size. The additional draft system power consumption was calculated on the basis of the volumetric flow rate of the flue gas through the control technology system and the flue gas pressure drop defined in the design parameter of the control technology. Indirect energy impacts, such as the energy to produce raw materials used for the control technology system, were not considered.

The major non-air quality impacts evaluated were the water consumption and disposal requirements for the byproduct and waste generated by each control technology. All quantities of water consumption and byproduct or waste generated by each control technology were calculated on a yearly basis. A water treatment system was added for the raw water's use in diluting the urea solution, but it is not used for cleaning outgoing water.

The following non-air quality environmental impacts were not included in the cost estimates.

- Byproduct and waste disposal – there is no significant impact to the current operations due to the addition of either an SCR or SNCR.
- Wastewater discharge – there is no wastewater discharge from either technology.

The SCR and SNCR technologies only reduce NO_x emissions, but the Revised SIP has significant environmentally beneficial impacts as compared to the FIP and the 2011 SIP scenarios, resulting in a reduction of overall air emissions, water consumption, raw materials use and coal combustion residuals ("CCRs") generated during plant operations.

Table 2 shows selected pollutants, including carbon dioxide ("CO_2"), and hazardous air pollutants emissions reductions under the Revised SIP as compared to the 2011 SIP and the EPA FIP scenarios. As can be seen from the table, the Revised SIP reduces the emissions of NO_x by 62 percent overall and also results in significant reduction of all other air emissions.

Table 2 San Juan Pollutant Emissions - Current Operations, Revised SIP, 2011 SIP and EPA FIP

SCENARIO	POLLUTANTS (TPY)[1]								
	NO_X	SO_2	PM	CO	CO_2[2]	VOCs	Hg[3]	Non-Hg Metals[4]	Acid Gases[4]
Baseline (current operations)	21,000	10,500	2,380	33,507	14,669,968	210	0.0842	5.4	1,488
Revised SIP	8,011	3,483	1,184	18,615	7,314,801	104	0.042	2.7	744
Revised SIP % Reduction	62%	67%	50%	44%	50%	50%	50%	50%	50%
2011 SIP	16,100	10,500	2,380	33,507	14,699,968	210	0.0842	5.4	1,488
2011 SIP % Reduction	23%	0%	0%	0%	0%	0%	0%	0%	0%
EPA FIP	3,502	10,500	2,380	33,507	14,699,968	210	0.0842	5.4	1,488
EPA FIP % Reduction	83%	0%	0%	0%	0%	0%	0%	0%	0%

Notes:

1. Annual emissions based on permitted hourly rate using an 85% capacity factor.
2. CO_2 numbers from the 2011 EPA Clean Air Markets Division database based upon 2011 operating data.
3. Hg numbers based on 1.2 lb/mmBtu Mercury and Air Toxics Standard Limit.
4. Non-Hg metals and acid gas air emissions from 2011 San Juan TRI.

Source: PNM

In addition to the decrease in overall air emissions, the Revised SIP will significantly reduce fugitive total suspended particulate ("TSP") emissions by approximately 50% from 407 tpy (2011 TRI) to 204 tpy. These reductions result from:

- Decrease in coal handling,
- Fewer TSP emissions from the pulverizer,
- Reduction in TSP from duct leaks,
- Lower emissions from the handling of CCRs (i.e., fly ash and bottom ash, spent activated carbon and scrubber gypsum), and
- Decreased emissions from both paved and unpaved roads resulting from fewer CCRs trucks traveling to the mine and fewer truck deliveries of raw materials

i. Benefits from Reduced Raw Material Usage

The reduced raw material deliveries that result from the Revised SIP also have the benefit of reducing emissions from trucks hauling these materials over the highways, and a reduction in emissions generated during the manufacture and processing of the raw materials. Table 3 shows the estimated annual raw material usage rate from the Revised SIP as compared to the FIP and 2011 SIP scenarios, and the current operations (Baseline). In general, the Revised SIP raw material usage rate is estimated to be 50 percent less than current conditions or those expected under the other scenarios.

Table 3 Raw Material Usage, Facility Wide

RAW MATERIAL	BASELINE, FIP, AND SIP SCENARIOS (TPY)	REVISED SIP (TPY)
Limestone[1]	172,104	86,052
Activated Carbon[1]	261	130
Coal[2]	5,334,729	2,667,364
No. 2 Diesel Oil[2]	2,014,671	1,007,336

1. Based on 2012 material usage data.

2. Based on 2011 material usage data.

Source: PNM

ii. Water and Wastewater Usage Benefits

San Juan is located in an area of the country in which water is both a scarce and a critical resource. Based on the 2011 San Juan water use data, under the Baseline, FIP, and SIP scenarios, San Juan will consume approximately 21,000 acre-feet of water per year. With the adoption of the Revised SIP, water usage is estimated to drop by approximately 53% to 10,161 acre-feet/year. Concentrated wastewater, which includes total and suspended solids from the wastewater management process, periodic boiler cleaning wastes and other process wastes, is discharged to on-site evaporation ponds under a zero discharge National Pollutant Discharge Elimination System ("NPDES") permit[12] and a state regulated discharge permit. Under this scenario, the generation of wastewater will be decreased by approximately 50 percent from 41 million gallons/year (2011 data) down to approximately 21 million gallons/year. For the FIP scenario, the wastewater generation will remain roughly the same rate as in 2011. [Source: PNM]

iii. CCRs Benefits

In 2011, San Juan generated approximately 1.426 million tons of fly and bottom ash along with 282,000 tons of gypsum generated from sulfur scrubbing operations and 261 tons of spent brominated activated carbon used to control mercury emissions. Collectively, this material is known as CCRs. The total CCRs, 1.71 million tons/year, is beneficially used as reclaim material at the San Juan Coal Mine. Similar CCRs generation rates would be expected under the FIP and 2011 SIP. However, under the Revised SIP, CCRs generation would be reduced by approximately 50% resulting in a reduction of CCRs generation by approximately 854,130 tpy.

[12] NPDES Permit No. NM0028606, issued February 2011.

As an added benefit, SNCR technology, as called for in the Revised SIP, will not require the use of a catalyst for NO_x reduction, which would result in the periodic replacement of spent catalyst due to catalyst poisoning by a number of alkali metals and trace elements. These catalyst poisons cause the catalyst to be treated as a hazardous waste during disposal, and this requires special handling and disposal practices. The FIP scenario requires the use of catalyst and will result in the generation of additional hazardous waste. [Source: PNM]

B. Existing pollution control strategies.

The BART analysis for NO_x reduction at San Juan also considered the existing pollution controls, including environmental system upgrades at San Juan that occurred between 2006 and 2009[13]. The system upgrade was performed by Babcock & Wilcox ("B&W") with the retrofit on all four San Juan units with state-of-the-art integrated low-NO_x combustion systems. The systems for all units included Low-NOx Burners ("LNB") (Model DRB-4Z) with over-fire air ("OFA"). To accommodate the new combustion system, work was performed on the boiler wind box plenum, secondary air feeder ducts, waterwall panel, and access platforms. Efforts were also made to improve fuel/air balancing.

In addition, underfire air ports were installed on Units 1 and 2 on the bottom two rows of the wall opposite to the burners. These ports serve to break up the reducing atmosphere on the boiler wall to protect the tubes from degradation.

[13] PNM entered into a consent decree with the Grand Canyon Trust, the Sierra Club, and the NMED on May 10, 2005.

B&W provided an emissions performance guarantee for the installation of LNB for NO_x reduction. NO_x emissions are guaranteed to a level of 0.293 lb/mmBtu on a 30-day rolling average basis for each unit.

C. Remaining useful life of San Juan.

The impact of the remaining useful life of the control technology on its cost-effectiveness was considered. In the 2013 BART Addendum, the remaining useful life of the controls was defined as 30 years. The remaining useful life is used to determine the cost recovery factor to annualize the capital investment for the technologies evaluated in the BART analysis. Previously, the remaining useful life was defined as 20 years. The 30 year useful life was used to match the EPA's BART analysis in its FIP.

D. Degree of visibility improvement.

Lastly, the visibility impact for each control technology evaluated in the BART analysis is considered. This step addresses the degree of improvement in visibility that may reasonably be anticipated to result from the use of the evaluated control technology for sources subject to BART. Visibility impact analysis is typically achieved through a two-phase process. First, a model is run using the pre-BART conditions to establish a baseline. In the typical analysis, the baseline consists of the existing emission control technologies and unit operations. Second, model runs are conducted for the control technologies identified for each unit during the BART engineering analysis. The model results are tabulated for the pre-BART and post-BART control scenarios over the time period of the meteorology modeled. The difference in the maximum value between the first and second phases is the expected degree of improvement in visibility.

In performing its visibility modeling and analysis for the Revised SIP, B&V utilized the approach described above, but compared the visibility improvements among the FIP, the SIP and

the Revised SIP. However, as discussed below, B&V also included visibility modeling for the baseline scenario for comparative purposes.

E. The Five-Step BART Analysis

The BART Guidelines describe the BART analysis as consisting of the following five-step approach:

Step 1: Identify All Available Retrofit Control Technologies;

Step 2: Eliminate Technically Infeasible Options;

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies;

Step 4: Evaluate Impacts and Document the Results; and

Step 5: Evaluate Visibility Impacts.[14]

i. Step 1: Identify All Available Retrofit Technologies

In Step 1 of the BART analysis, all available retrofit control technologies that have a practical potential for application at San Juan were identified. These technologies are considered as available technologies. The technology considered could be a change in plant operation method, addition/modification of emissions control systems, or a combination thereof for control of a pollutant. Control technologies for NO_x were identified and a description of the technology, information on the working principle, retrofit considerations, advantages and disadvantages of the technology are provided in Section 3.0 of the 2013 BART Addendum. In addition to adding NO_x control technology to the San Juan units, retiring the units is another viable option for meeting the emission reduction and visibility requirements.

[14] *Id.* at page 39164.

While NOx is the focus of this proceeding, it should be noted that both NMED and EPA previously determined that the pulse jet fabric filters installed to comply with the consent decree were BART for PM control. Also, because New Mexico is participating in the Western Regional Air Partnership SO_2 emissions trading program, PNM was not required to analyze SO_2 emission control technologies for San Juan.

There are two approaches to achieving a reduction in NO_x emissions: combustion control and post-combustion control. Combustion control methods seek to suppress NO_x formation during the combustion process by controlling the flame temperature and fuel/oxygen ratio. Combustion control methods include LNBs and OFA combustion optimization systems. The post-combustion controls consist of SNCR and SCR systems or a combination of the two systems (i.e. hybrid system). SNCR and SCR are flue gas treatment technologies that reduce NO_x after its formation and use either urea or ammonia as a reagent. SCR technology also uses multiple layers of reduction catalyst. Other NO_x reduction techniques were also identified, including emerging technologies.

The NO_x control technologies that were identified for retrofit at San Juan are listed below. A description of each technology can be found in the 2013 BART Addendum.

- LNB and OFA
- SNCR
- SCR
- SNCR/SCR Hybrid
- LNB, OFA and SNCR
- LNB, OFA and SCR
- LNB, OFA and Hybrid

- Gas Reburn
- Mobotec Rotating Overfire Air ("ROFA") and ROTAMIX
- NO_xStar
- ECOTUBE
- PowerSpan
- Phenix Clean Combustion
- e-SCRUB
- PerNOxide

ii. Step 2: Eliminate Technically Infeasible Options

Step 2 of the BART analysis involves the evaluation of all the identified available retrofit control technologies to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar type of source. Two terms, available and applicable, are used to define the technical feasibility of a control technology. According to the 1990 Draft Workshop Manual, a technology is considered applicable if it can reasonably be installed and operated on the source type under consideration. A technology is deemed an available technology if it is being offered commercially by vendors or is in commercial demonstration or licensing. The commercially available technology is applicable if it has been previously installed and operated at a similar type of source, or at a source with similar gas stream characteristics. Technologies that are in development and testing stages are classified as not available. Other factors that are considered when determining the technical feasibility of a technology include the following:

- Size of the unit
- Location of the proposed technology
- Operating problems after retrofit of technology

- Space constraints
- Reliability
- Adverse effects on the rest of the facility
- Adverse community impacts

Additionally, a technology is technically infeasible if its level of emissions control does not achieve the required permit emissions limit applied to the source by the regulating agency. Finally, if there are multiple control technologies that achieve the required emission limit, the BART procedure allows for the consideration of the less costly control technology, eliminating the need to evaluate higher cost technologies. Section 4.0 of the April 2013 BART Addendum provides details of Step 2 of the BART analysis.

The following is a list of NO_x control technologies that were identified as available for retrofit at San Juan in the BART analysis:

- SCR
- SNCR
- SNCR with Unit Retirement

The following list of NOx control technologies were identified as infeasible:

- Gas Reburn
- Mobotec ROFA and ROTAMIX
- NO_xStar
- ECOTUBE
- PowerSpan
- Phenix Clean Combustion

- e-SCRUB
- PerNOxide

The 2007 BART analysis determined the SCR/SNCR hybrid technology to be a technically feasible technology. It was evaluated further in previous submittal documents, but it was not further evaluated as part of 2013 BART Addendum because of cost effectiveness considerations and insufficient emissions control.

iii. Step 3: Evaluate Control Effectiveness of Control Technologies

The evaluation of the effectiveness of control technologies is addressed in the S&L testimony.

iv. Step 4: Evaluate Impacts and Document Results

The evaluation of the impacts and documentation of results is addressed in the S&L testimony. Furthermore, the cost-effectiveness of each control technology was calculated from the cost of compliance and the amount of pollutant reduced. The cost-effectiveness is defined as the cost of control per amount of pollutant removed. The cost of control takes into account the impact analyses performed for San Juan. The reduced emissions were estimated on a yearly basis according to the reduction from the Baseline emissions level. The cost-effectiveness results are presented in Exhibit 3. In addition to the cost effectiveness values, another method of comparing costs is incremental cost-effectiveness, which is the change in cost that results from comparing one control option to another. The incremental cost effectiveness indicates the additional cost to increase the removal of pollutant when comparing technologies that have different emission removal capabilities. This metric is particularly useful when comparing several control technologies' costs at the same unit. The incremental cost effectiveness in thousands of dollars per ton of emission reduced to go from an SNCR to an SCR is $6,762/ton for Unit 1, $7,766/ton

for Unit 2, $6,326/ton for Unit 3, and $5,636/ton for Unit 4. The cost-effectiveness values were based on 2013 dollars.

For all the additional NO_x control technologies evaluated, a summary table was developed for the impact analysis performed and the resultant cost-effectiveness. Exhibit B&V-3 presents the final evaluations for all four units. The expected after-control emissions levels are also included in the table. Cost-Effectiveness Comparison Exhibit B&V-3 clearly shows that on a facility wide basis the Revised SIP is the most cost effective scenario at $1,050/ton verses the SIP at $5,561/ton and the FIP at $6,228/ton.

For the cost effectiveness comparison, the SCR is the most expensive option, because of the total capital investment costs and the total annual costs are significantly more expensive than the other options. Additionally, the energy impacts for the FIP scenario are much higher than the other options primarily because of the pressure drop across the SCR. The Revised SIP is significantly less expensive, because emissions from two units are completely eliminated at no cost by retiring the units. Looking between the units, Unit 1 and 2 costs are approximately the same, and Unit 3 costs are higher than Unit 4. This difference is due to the additional cost required for the installation of these technologies on the inside units. Specifically, the four units were built side-by-side in a row with minimum spacing between units. Units 1 and 4 are outside units, whereas, Units 2 and 3 are inside units. Thus, accessibility to Units 2 and especially 3 is limited by the plant layout and the presence of other balance-of-plant equipment, such as the coal conveyor. The reduced accessibility means that the SCR system will need to be built in smaller pieces, thus increasing construction costs as compared to their sister units.

v. Step 5: Evaluate Visibility Impacts.

See next Section.

F. CALPUFF Modeling and Visibility Impacts

1. Air Dispersion Model Used

The CALPUFF modeling system is recommended as the preferred modeling approach for use in BART analyses. CALPUFF and its meteorological model, CALMET, are designed to handle the complexities posed by complex terrain, large source-receptor distances, chemical transformation and deposition, as well as other issues related to Class I visibility impacts. The CALPUFF modeling system has been adopted by the EPA as a guideline model for source-receptor distances greater than 50 kilometers and for use on a case-by-case basis in complex flow situations for shorter distances (68 FR 18440-18482). CALPUFF is recommended for Class I impact assessments by the Federal Land Managers Workgroup (FLAG 2000 and FLAG 2010[15]) and the Interagency Workgroup on Air Quality Modeling (IWAQM) (EPA 1998). The final BART guidance recommends CALPUFF as "the best modeling application available for predicting a single source's contribution to visibility impairment" (70 FR 39122).

CALPUFF is a non-steady-state meteorological and air quality modeling system that assesses long range transport of pollutants. It is a Lagrangian, puff transport and dispersion model that advects Gaussian puffs of multiple pollutants from modeled sources. CALPUFF's algorithms have been designed to be applicable on spatial scales from a few tens of meters to hundreds of kilometers from a source. It includes algorithms for near-field effects such as building downwash, stack tip downwash, and transitional plume rise, as well as processes important in the far-field, such as chemical transformation, wet deposition and dry deposition. CALPUFF contains an option to allow puff splitting in the horizontal and vertical directions, which extends the distance range of the model. The primary outputs from CALPUFF are hourly concentrations and hourly deposition fluxes evaluated at user-specified receptor locations.

[15] FLAG 2010 updated several CALPUFF parameters contained in FLAG 2000 and reaffirmed CALPUFF to be the Class I model of choice.

2. Consistency with EPA Modeling Methodology/Modeling Assumptions

B&V conducted BART air modeling analyses using the CALPUFF air dispersion modeling system for San Juan. To aid potential settlement discussions with EPA and for consistency with EPA's previous modeling conducted as part of the FIP[16], B&V utilized the EPA CALPUFF modeling information provided as part of a Freedom of Information Act ("FOIA") request and described in a technical support document[17].

B&V conducted initial verification modeling using EPA's FIP modeling runs provided in the FOIA request to ensure consistency. The results of the EPA FIP run by B&V matched EPA's modeling results, indicating that the modeling methodologies and inputs utilized in the analysis were the same as those employed by the EPA. These results were made available to EPA on September 19, 2012. B&V then conducted four modeling runs using the same, confirmed methodologies and inputs employed by EPA in the FIP, to represent the Baseline and three additional BART technology scenarios. Specifically, B&V used the compiled CALMET data set, EPA specified model versions and modified EPA's modeling input files to include the source specific parameters for the modeling the three technology scenarios identified:

- SCR – EPA FIP.
- SNCR – 2011 SIP.
- SNCR with Unit Retirement – Revised SIP.

For this BART modeling analysis, the modeled CALPUFF domain, receptors, constant ammonia concentrations, ozone and CALMET data used in the analysis all came directly from the EPA modeling. The versions of the CALPUFF modeling system used for this analysis were also

[16] Federal Register/ Vol. 76, No. 3/ Wednesday, January 5, 2011. EPA-R06-OAR-0846-0001.
[17] Technical Support Document; Visibility Modeling for BART Determination: San Juan Generating Station, New Mexico. EPA-R06-OAR-0846-0003.

consistent with the aforementioned EPA modeling described in the EPA Technical Support Document from the 2011 FIP. In other words, B&V only modified EPA's modeling input files to include the source-specific parameters for the modeling the three technology scenarios identified above.

The latest BART modeling incorporated San Juan's new SO_2 and TPM emission rates of 0.15 lb/mmBtu and 0.034 lb/mmBtu, respectively, in the current New Source Review ("NSR") Permit[18] dated August 31, 2012. PNM voluntarily agreed to the lower SO_2 emission rate to support the SIP, whereas the lower $PM_{2.5}$ limit resulted from an existing permit requirement to include $PM_{2.5}$ condensable emissions. The new limit is the total of the filterable and condensable $PM_{2.5}$ emissions. Therefore, these new emission limits have been incorporated into the Baseline scenario, as well as the three BART technology scenarios. Additionally, BART modeling for the Revised SIP includes the TPM emission rates as discussed above and a reduced SO_2 emission rate of 0.10 lb/mmBtu as agreed upon in the Term Sheet between EPA, NMED, and PNM. Below are the four scenarios that were evaluated:

- **Scenario 1: Baseline.** Units 1-4 operating only with existing air pollution control technology (NOx at 0.30 lb/mmBtu) and newly permitted SO_2 and TPM emission rates of 0.15 lb/mmBtu and 0.034 lb/mmBtu, respectively.
- **Scenario 2: FIP.** Units 1-4 operating with existing air pollution control technology and with new SCR installation; NO_X at 0.05 lb/mmBtu and newly permitted SO_2 and TPM emission rates of 0.15 lb/mmBtu and 0.034 lb/mmBtu, respectively.
- **Scenario 3: 2011 SIP.** Units 1-4 operating with existing air pollution control technology and with new SNCR installation; NO_X at 0.23 lb/mmBtu and newly

[18] NSR Permit No. 0063-M8.

permitted SO_2 and TPM emission rates of 0.15 lb/mmBtu and 0.034 lb/mmBtu, respectively.

- **Scenario 4: Revised SIP.** Units 2 & 3 retired, Units 1 & 4 operating with existing air pollution control technology and with new SNCR installation; NO_X at 0.23 lb/mmBtu, new permitted TPM emission rate 0.034 lb/mmBtu, and a reduced SO_2 emission rate of 0.10 lb/mmBtu (as specified in the Term Sheet).

3. CALPUFF Modeling Results

The CALPUFF modeling results of baseline scenario modeling are presented in Table 4. The baseline scenario impacts were used to establish a comparison for the BART control technology impacts. The results of the modeling for the BART emissions control technology scenarios are presented in Tables 5 through 7. Table 5 illustrates the EPA FIP scenario and resultant visibility impacts of the entire facility using SCR technology installation on each unit. Table 6 illustrates the 2011 SIP scenario and resultant visibility impacts of the entire facility using SNCR technology installation on each unit. Finally, Table 7 illustrates the Revised SIP scenario and resultant visibility impacts of Units 2 & 3 retired and Units 1 & 4 with new SNCR installation.

Table 4 Baseline Visibility Results, 98th Percentile (dv)

Class I Area	2001	2002	2003	Average	Maximum
Arches	3.51	0.96	1.52	1.99	3.51
Bandelier	1.40	1.30	1.03	1.24	1.40
Black Canyon	1.36	1.41	0.63	1.13	1.41
Canyonlands	4.66	2.12	2.29	3.02	4.66
Capitol Reef	2.39	0.46	0.66	1.17	2.39
Grand Canyon	0.93	0.26	0.38	0.52	0.93
Great Sand Dunes	0.85	1.54	1.08	1.16	1.54
La Garita	1.39	1.94	1.14	1.49	1.94
Maroon Bells	0.71	0.61	0.34	0.55	0.71
Mesa Verde	5.16	5.22	5.02	5.13	5.22
Pecos	0.94	1.27	1.03	1.08	1.27
Petrified Forest	0.52	0.46	0.38	0.45	0.52
San Pedro	2.21	1.98	2.08	2.09	2.21
West Elk	1.59	1.43	0.68	1.24	1.59
Weminuche	2.15	2.95	2.02	2.37	2.95
Wheeler Peak	1.12	1.10	0.91	1.04	1.12

Table 5 EPA FIP Visibility Results, 98th Percentile (dv)

Class I Area	2001	2002	2003	Average	Maximum
Arches	1.13	0.49	0.46	0.69	1.13
Bandelier	0.49	0.49	0.42	0.47	0.49
Black Canyon	0.42	0.42	0.26	0.36	0.42
Canyonlands	1.57	0.69	0.75	1.00	1.57
Capitol Reef	0.83	0.25	0.32	0.47	0.83
Grand Canyon	0.33	0.13	0.20	0.22	0.33
Great Sand Dunes	0.32	0.50	0.35	0.39	0.50
La Garita	0.50	0.58	0.36	0.48	0.58
Maroon Bells	0.28	0.19	0.14	0.20	0.28
Mesa Verde	2.17	2.15	2.33	2.22	2.33
Pecos	0.40	0.48	0.33	0.40	0.48
Petrified Forest	0.20	0.16	0.22	0.19	0.22
San Pedro	0.72	0.75	0.67	0.71	0.75
West Elk	0.46	0.40	0.23	0.37	0.46
Weminuche	0.83	0.92	0.73	0.82	0.92
Wheeler Peak	0.42	0.45	0.32	0.40	0.45

Table 6 2011 SIP Visibility Results, 98th Percentile (dv)

Class I Area	2001	2002	2003	Average	Maximum
Arches	2.67	0.72	1.15	1.51	2.67
Bandelier	1.08	0.98	0.80	0.96	1.08
Black Canyon	1.01	1.07	0.47	0.85	1.07
Canyonlands	3.71	1.62	1.81	2.38	3.71
Capitol Reef	1.82	0.38	0.56	0.92	1.82
Grand Canyon	0.72	0.24	0.30	0.42	0.72
Great Sand Dunes	0.65	1.15	0.81	0.87	1.15
La Garita	1.05	1.47	0.85	1.12	1.47
Maroon Bells	0.53	0.46	0.27	0.42	0.53
Mesa Verde	4.67	4.43	4.47	4.52	4.67
Pecos	0.73	1.00	0.78	0.84	1.00
Petrified Forest	0.39	0.34	0.31	0.34	0.39
San Pedro	1.72	1.56	1.59	1.62	1.72
West Elk	1.21	1.07	0.51	0.93	1.21
Weminuche	1.74	2.36	1.61	1.90	2.36
Wheeler Peak	0.86	0.83	0.67	0.79	0.86

Table 7 Revised SIP Visibility Results, 98th Percentile (dv)

Class I Area	2001	2002	2003	Average	Maximum
Arches	1.37	0.35	0.55	0.76	1.37
Bandelier	0.52	0.48	0.39	0.46	0.52
Black Canyon	0.49	0.52	0.22	0.41	0.52
Canyonlands	1.99	0.82	0.91	1.24	1.99
Capitol Reef	0.89	0.16	0.24	0.43	0.89
Grand Canyon	0.33	0.09	0.13	0.18	0.33
Great Sand Dunes	0.31	0.57	0.39	0.42	0.57
La Garita	0.50	0.71	0.41	0.54	0.71
Maroon Bells	0.26	0.21	0.12	0.20	0.26
Mesa Verde	2.80	2.65	2.61	2.69	2.80
Pecos	0.35	0.47	0.37	0.39	0.47
Petrified Forest	0.19	0.16	0.13	0.16	0.19
San Pedro	0.87	0.74	0.79	0.80	0.87
West Elk	0.58	0.53	0.25	0.45	0.58
Weminuche	0.85	1.21	0.79	0.95	1.21
Wheeler Peak	0.40	0.39	0.33	0.37	0.40

4. Comparison of visibility improvement for technologies considered

Based on the approved approach, visibility modeling was conducted for the four BART scenarios previously discussed. The 2011 SIP and Revised SIP scenarios visibility results were then compared to the EPA FIP visibility results. The results of maximum visibility difference (in deciviews) projected at any of the 16 Class I areas for the BART control technologies at any time over the 2001 to 2003 period were presented above in Tables 6 and 7, respectively. The visibility results for the Baseline Scenario have been included for informational purposes as new SO_2 and PM limits apply, but were not analyzed further.

Tables 8 and 9 evaluate the maximum visibility impact values from the Revised SIP results illustrated above in Table 7 as compared to the maximum values from the EPA FIP results previously provided in Table 5. This comparison illustrates overall visibility improvements similar to the EPA FIP as shown in Table 9. The results indicate that visibility impacts at five Class I areas are equal to or better than visibility impacts projected for the EPA FIP scenario.

Additionally, the visibility impacts for the remaining Class I areas are less than a 0.50 dv difference from EPA's FIP scenario compared on an area-by-area basis. The differences between the EPA FIP and Revised SIP visibility impacts for those remaining Class I areas range from 0.06 dv to a maximum of 0.47 dv; the latter of which is at Mesa Verde. Again, it should be noted that a change of 1 dv is generally regarded as the limit of perceptible change in visibility[19] to the human eye. Figure 1 provides an illustaration of San Juan's maximum visibility impact at Mesa Verde National Park using EPA's WinHaze software which simulates

[19] 70 FR 39118; July 6, 2005.

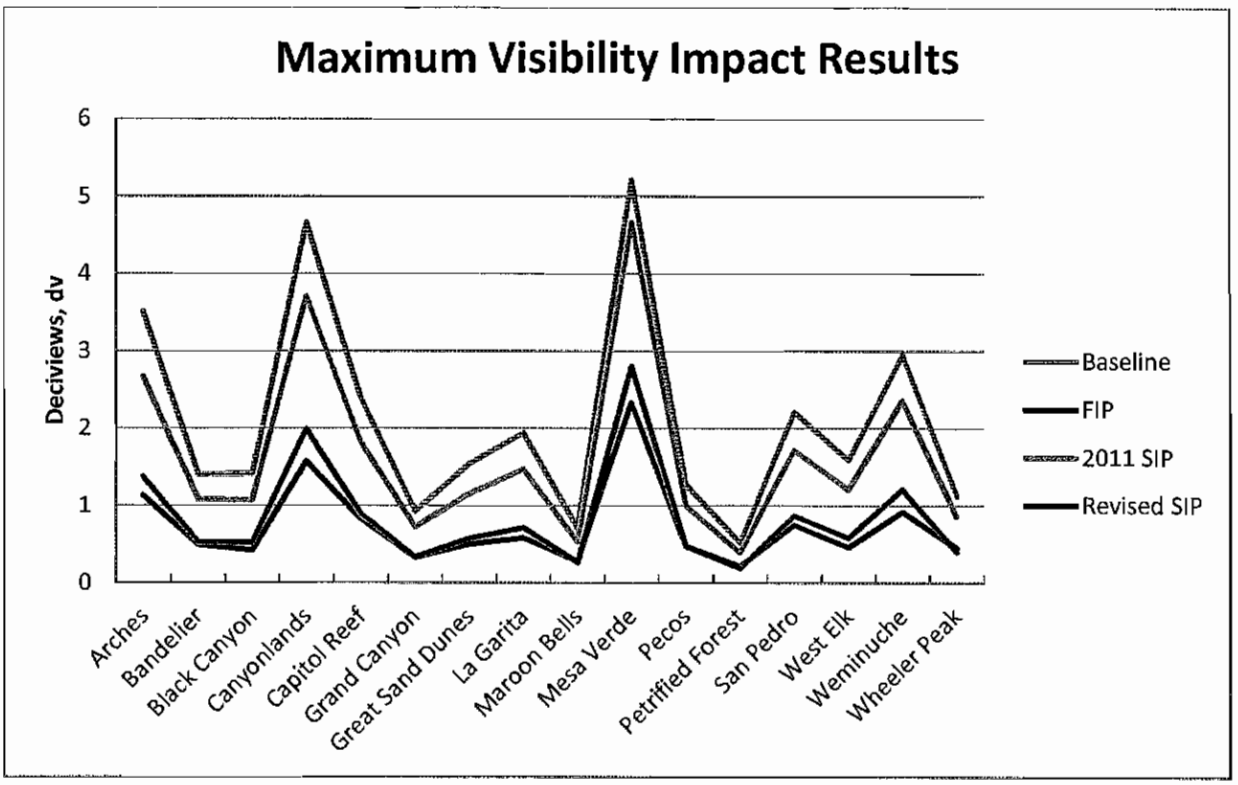
visibility impacts. Specifically, Figure 1 compares the visibility based on both the EPA FIP and Revised SIP scenarios and shows the visible impact difference between the two scenarios (i.e., 0.47 dv) is imperceptible.

gure 1 - SJGS Maximum Visibility Impact at Mesa Verde – EPA FIP vs. Revised SIP

FIP Scenario (2.33 dv) Revised SIP Scenario (2.80 dv)

Furthermore, Figure 2 illustrates the visibility impacts at each Class I area for each BART technology scenario. As illustrated in Figure 2, the visibility curve for the Revised SIP closely matches the EPA FIP scenario's visibility curve (both of which provided marked visibility improvements over the Baseline and 2011 SIP scenarios).

Figure 2 Maximum Visibility Impact Results



As previously noted, the projected visibility impacts for the Revised SIP scenario are all within a value of 0.5 dv of the FIP. Tables 8 through 13 include a summary of CALPUFF's predicted average and maximum delta dv change at each Class I area, as well as days over a 0.5 dv and 1.0 dv threshold. These summary tables also illustrate the frequency of the occurrence of the level of visibility impact as compared to that for EPA's FIP. These results of the comparison of the average and maximum days indicate that approximately half or more of the number of Class I areas are comparable to the predicted impacts for the EPA FIP. Figures 3 through 6 illustrate the number of days over comparison at each Class I area for each BART technology scenario. As illustrated in Figure 3 through 6, the Revised SIP closely matches the EPA FIP scenario's day's comparison curves.

Table 8 Maximum Delta Deciview (dv) FIP minus the SIP, 98th Percentile

Class I Area	EPA FIP	2011 SIP	EPA FIP minus 2011 SIP
Arches	1.13	2.67	-1.54
Bandelier	0.49	1.08	-0.59
Black Canyon	0.42	1.07	-0.65
Canyonlands	1.57	3.71	-2.14
Capitol Reef	0.83	1.82	-0.99
Grand Canyon	0.33	0.72	-0.39
Great Sand Dunes	0.50	1.15	-0.65
La Garita	0.58	1.47	-0.89
Maroon Bells	0.28	0.53	-0.25
Mesa Verde	2.33	4.67	-2.34
Pecos	0.48	1.00	-0.52
Petrified Forest	0.22	0.39	-0.17
San Pedro	0.75	1.72	-0.97
West Elk	0.46	1.21	-0.75
Weminuche	0.92	2.36	-1.44

Wheeler Peak	0.45	0.86	-0.41

Table 9 Delta Deciview (dv) EPA FIP minus the Revised SIP, 98th Percentile

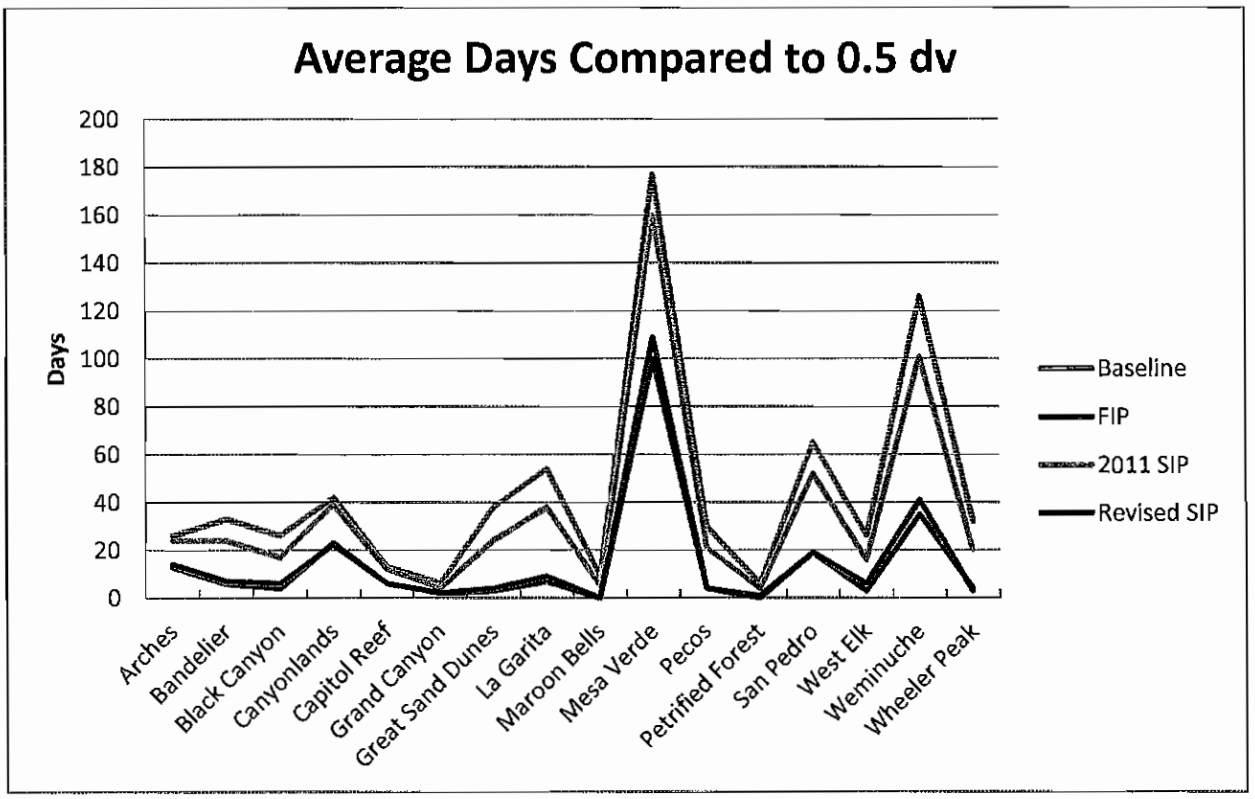
Class I Area	EPA FIP	Revised SIP	EPA FIP minus 2011 SIP
Arches	1.13	1.37	-0.24
Bandelier	0.49	0.52	-0.03
Black Canyon	0.42	0.52	-0.1
Canyonlands	1.57	1.99	-0.42
Capitol Reef	0.83	0.89	-0.06
Grand Canyon	0.33	0.33	0
Great Sand Dunes	0.50	0.57	-0.07
La Garita	0.58	0.71	-0.13
Maroon Bells	0.28	0.26	0.02
Mesa Verde	2.33	2.80	-0.47
Pecos	0.48	0.47	0.01
Petrified Forest	0.22	0.19	0.03
San Pedro	0.75	0.87	-0.12
West Elk	0.46	0.58	-0.12
Weminuche	0.92	1.21	-0.29
Wheeler Peak	0.45	0.40	0.05

Table 10 Average Days Compared To 0.5 dv

Class I Area	Baseline	FIP	SIP	Revised SIP	FIP - SIP	FIP - Revised SIP
Arches	26	13	24	14	-11	-1
Bandelier	33	6	24	7	-18	-1
Black Canyon	26	4	17	6	-13	-2
Canyonlands	42	23	39	22	-16	1
Capitol Reef	13	6	12	6	-6	0
Grand Canyon	6	2	4	2	-2	0
Great Sand Dunes	38	3	24	4	-21	-1
La Garita	54	7	38	9	-31	-2
Maroon Bells	9	0	5	0	-5	0
Mesa Verde	177	109	160	100	-51	9
Pecos	30	4	21	4	-17	0
Petrified Forest	6	1	4	0	-3	1
San Pedro	65	19	52	19	-33	0
West Elk	26	3	16	6	-13	-3
Weminuche	126	35	101	41	-66	-6
Wheeler Peak	32	4	20	3	-16	1

Note: Maximum Number of Days with Average Impacts Equal to or Greater than 0.5 Deciviews.

Figure 3 Average Days Compared To 0.5 dv[20]

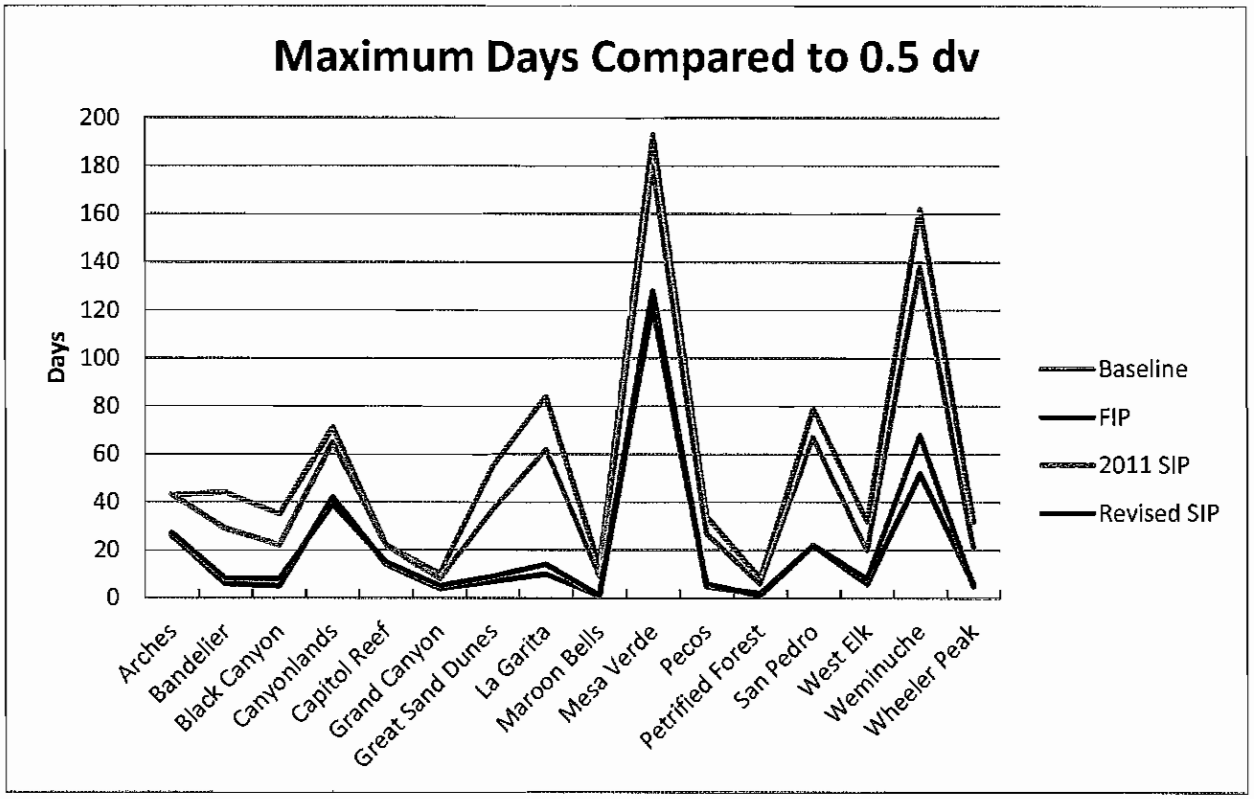


[20] Maximum Number of Days with Average Impacts Equal to or Greater than 0.5 Deciviews

Table 11 Maximum Days Compared To 0.5 dv

Class I Area	Baseline	FIP	SIP	Revised SIP	FIP - SIP	FIP - Revised SIP
Arches	43	26	43	27	-17	-1
Bandelier	44	6	29	8	-23	-2
Black Canyon	35	5	22	8	-17	-3
Canyonlands	71	42	65	39	-23	3
Capitol Reef	22	14	22	15	-8	-1
Grand Canyon	10	4	8	5	-4	-1
Great Sand Dunes	55	7	37	9	-30	-2
La Garita	84	10	62	14	-52	-4
Maroon Bells	13	1	9	1	-8	0
Mesa Verde	193	128	180	122	-52	6
Pecos	34	5	27	6	-22	-1
Petrified Forest	8	2	6	1	-4	1
San Pedro	79	22	67	22	-45	0
West Elk	32	6	20	8	-14	-2
Weminuche	162	52	138	68	-86	-16
Wheeler Peak	32	6	21	5	-15	1
Note: Maximum Number of Days with Maximum Impacts Equal to or Greater than 0.5 Deciviews.						

Figure 4 Maximum Days Compared To 0.5 dv[21]

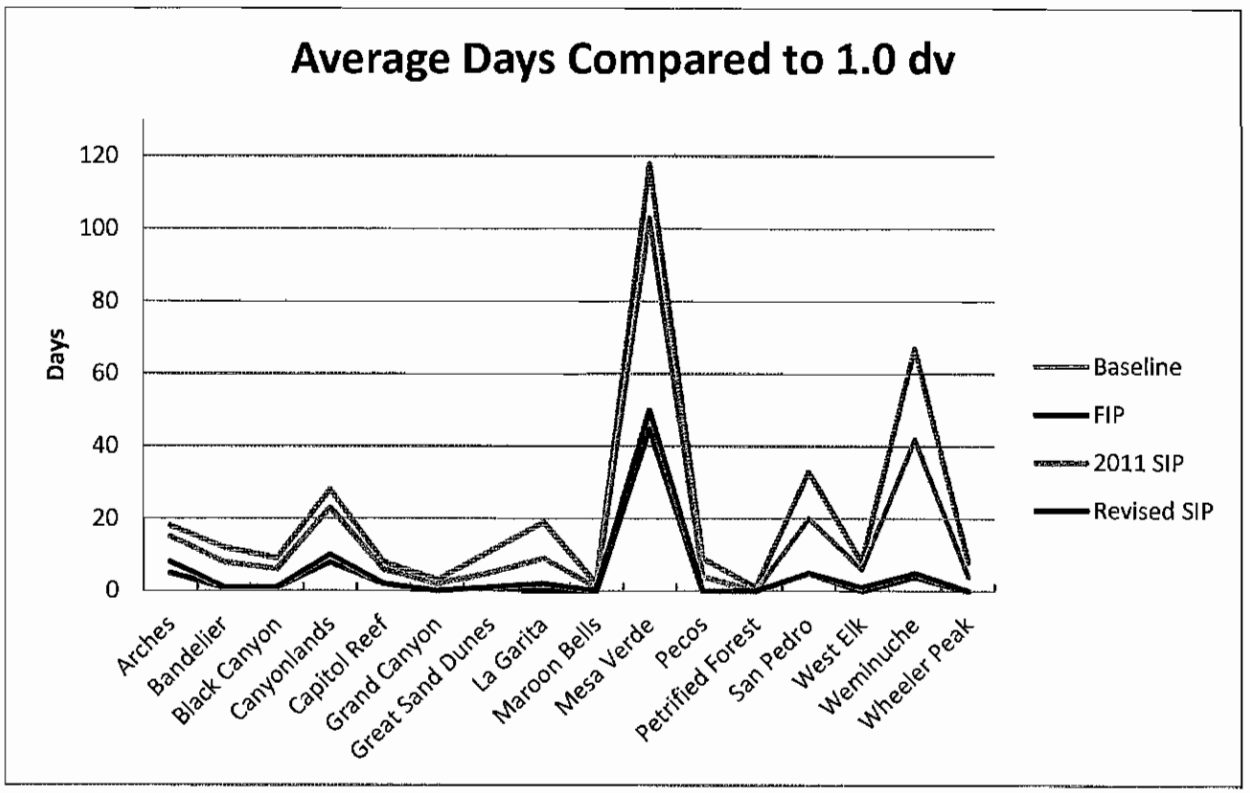


[21] Maximum Number of Days with Maximum Impacts Equal to or Greater than 0.5 Deciviews

Table 12 Average Days Compared To 1.0 dv

Class I Area	Baseline	FIP	SIP	Revised SIP	FIP - SIP	FIP - Revised SIP
Arches	18	5	15	8	-10	-3
Bandelier	12	1	8	1	-7	0
Black Canyon	9	1	6	1	-5	0
Canyonlands	28	8	23	10	-15	-2
Capitol Reef	8	2	6	2	-4	0
Grand Canyon	3	0	2	0	-2	0
Great Sand Dunes	11	1	5	1	-4	0
La Garita	19	0	9	2	-9	-2
Maroon Bells	2	0	1	0	-1	0
Mesa Verde	118	45	103	50	-58	-5
Pecos	9	0	4	0	-4	0
Petrified Forest	1	0	0	0	0	0
San Pedro	33	5	20	5	-15	0
West Elk	8	0	6	1	-6	-1
Weminuche	67	4	42	5	-38	-1
Wheeler Peak	8	0	4	0	-4	0
Note: Maximum Number of Days with Average Impacts Equal to or Greater than 1.0 Deciviews						

Figure 5 Average Days Compared To 1.0 dv[22]

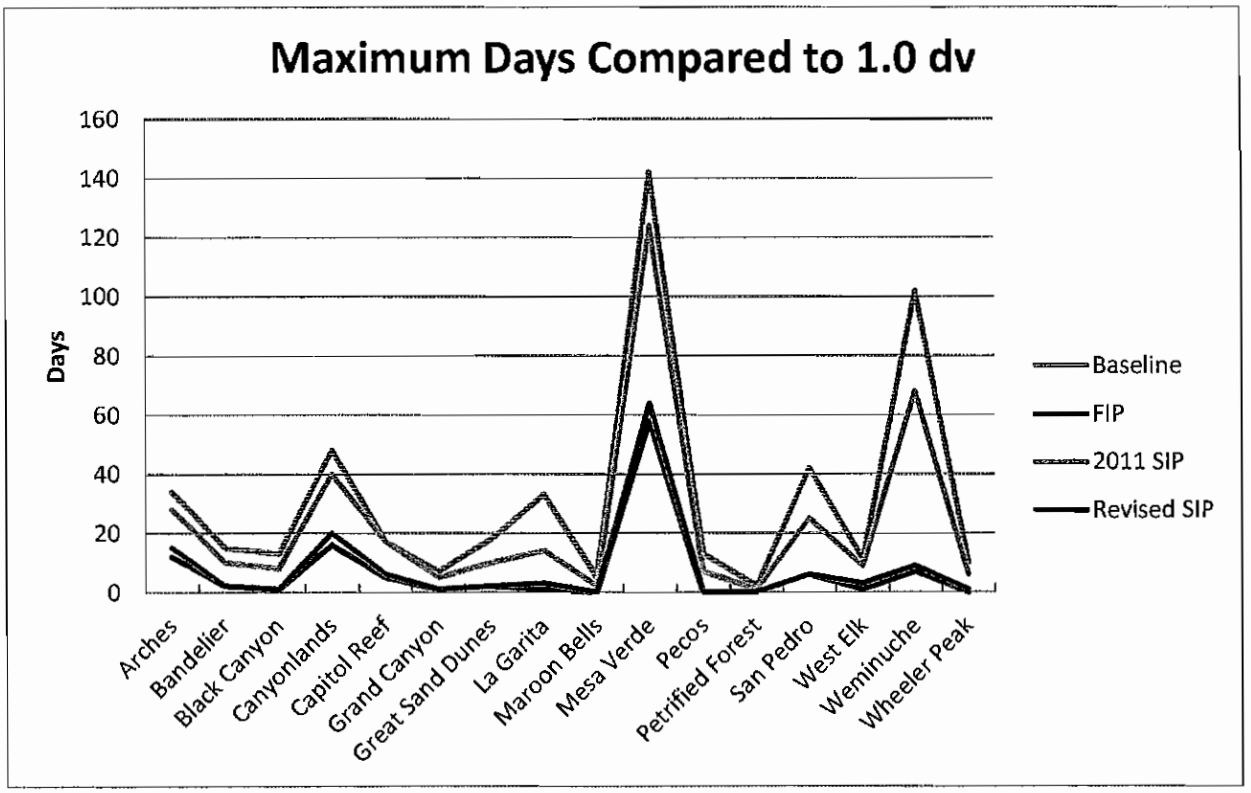


[22] Maximum Number of Days with Average Impacts Equal to or Greater than 1.0 Deciviews

Table 13 Maximum Days Compared To 1.0 dv

Class I Area	Baseline	FIP	SIP	Revised SIP	FIP - SIP	FIP - Revised SIP
Arches	34	12	28	15	-16	-3
Bandelier	15	2	10	2	-8	0
Black Canyon	13	1	8	1	-7	0
Canyonlands	48	16	40	20	-24	-4
Capitol Reef	17	5	17	6	-12	-1
Grand Canyon	7	1	5	1	-4	0
Great Sand Dunes	18	2	10	2	-8	0
La Garita	33	1	14	3	-13	-2
Maroon Bells	5	0	2	0	-2	0
Mesa Verde	142	58	124	64	-66	-6
Pecos	13	0	7	0	-7	0
Petrified Forest	2	0	1	0	-1	0
San Pedro	42	6	25	6	-19	0
West Elk	11	1	9	3	-8	-2
Weminuche	102	7	68	9	-61	-2
Wheeler Peak	10	0	6	1	-6	-1
Note: Maximum Number of Days with Maximum Impacts Equal to or Greater than 1.0 Deciviews.						

Figure 6 Maximum Days Compared To 1.0 dv[23]



[23] Maximum Number of Days with Maximum Impacts Equal to or Greater than 1.0 Deciviews

I. BART Cost Effectiveness Analysis

The visibility improvement cost-effectiveness was calculated from the total Annualized Cost to implement the additional control technology alternatives shown in S&L's testimony and the amount of NO_x reduced. The maximum modeled visibility improvement for each BART control technology scenario at each of the 16 Federal Class I areas was used for the determination of the visibility improvement cost-effectiveness in $/deciview ($/dv). The Baseline was compared with the three BART control technology scenarios, and is shown in the visibility improvement cost effectiveness summary in Table 14:

- Baseline to the EPA FIP.
- Baseline to the 2011 SIP.
- Baseline to the Revised SIP.

As shown in Table 14, the cost to install the Revised SIP control technology on a $/dv basis is a fraction of the cost per dv improvement as compared to either the FIP or SIP BART control technologies.

Table 14 Visibility Improvement Cost-Effectiveness Summary

Visibility Scenario	Total Annualized Cost (TAC) ($1,000)	Scenario Maximum Deciview Change (dv)	Maximum Improvement ($1,000/dv)
Baseline to FIP	$108,820	3.09	$35,217,000
Baseline to SIP	$27,248	0.95	$28,682,000
Baseline to Revised SIP	$13,624	2.67	$5,103,000

VI. National Park Service Comments on the Revised SIP

On July 24, 2013, the National Park Service ("NPS") submitted comments on the Revised SIP to NMED. B&V provides response to the following NPS comments:

A. Comment: "PNM did not demonstrate that the State Alternative SNCR on two units and shut down of two units is better than EPA's proposed BART determination SCR on four units."

Response: The 2013 BART Addendum is an update to the 2007 BART Analysis and subsequent submittals. The NMED, through the 2010 BART SIP process and NMEIB in approval of the BART SIP in 2010, determined that BART for San Juan was the installation of four (4) SNCRs at a NOx emission rate of 0.23 lb/mmBtu. The intent as noted in the 2013 BART Addendum submittal was to provide new information regarding technology, costs and related modeling results to NMED which also considered the conditions contained in the February 2013 Term Sheet agreement between EPA, NMED and PNM. The intent of the application was not to demonstrate a potential "better –than-BART" alternative.

B. Comment: "PNM did not follow the BART guidelines to model maximum 24-hour emissions, so model results do not accurately estimate the visibility impacts. Actual 24-hour maximum NOx emissions should have been used for the baseline, and compared to the percentage emissions reductions for each control technology (23% for SNCR and 83% SCR)."

Response: The emissions used in the modeling were assumed to be the maximum 24-hour emissions. These numbers assumed an average values provide a good basis for modeling the increase pollution or decrease in visibility, because San Juan will not be operating at maximum emission conditions all the time. Maximum emissions may be due to an upset condition (plant or meteorological), and using an outlying data point to model normal scenarios is not practical.

EPA has previously responded to this issue on other BART analyses. In a Nevada response[24,25], EPA noted:

> *We recognize that sources complying with a 30 day average may at times operate above the 30 day average emission limit but they will have to balance those times by operating below the limit at other times. This variability is difficult to assess, though a prudent source will strive to remain below the 30-day emission limit as much as possible. In some instances, it may be appropriate to model a slightly higher emission rate when limiting the emissions using a 30-day average to account for potential variability, when the amount of variability is well understood. In this case, we believe using the 30 day average emission limit is a reasonable approach to project future emissions that would reasonably be anticipated in accordance with BART guidelines because we have no reason to think the variability in the future case will be large enough to impact our evaluation of the five factors.*
>
> *The BART guidelines allow for some flexibility in how to assess visibility improvements due to BART controls. As we discuss elsewhere in this response, we consider issues related to frequency, magnitude and duration of emission levels that may occur in comparison to [the] 30-day limit and the potential for impacting the visibility projections. We concluded that the amount of times the variability of emissions would exceed [the limit] on a maximum daily process would not be expected to be of sufficient magnitude to have a large impact on our visibility improvement estimates. We agree that*

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24 81742 Federal Register / Vol. 76, No. 249 / Wednesday, December 28, 2011 / Rules and Regulations

25 81742 Federal Register / Vol. 76, No. 249 / Wednesday, December 28, 2011 / Rules and Regulations

the BART guidelines allow for some flexibility in how visibility improvement determinations are conducted. We considered processes similar to Colorado's approach, including the methodology given as an example in the BART guidelines, but determined we did not have sufficient information to accurately estimate the future maximum 24-hour emission rate and furthermore concluded that existing modeling indicated that small changes would not significantly impact our visibility improvement estimates. Overall, the BART guidelines give some flexibility to how the visibility improvements can be calculated and the approach that we have used is reasonable based on the information available and is not inconsistent with the BART guidelines.

The ultimate point is that the EPA accepts the use of 30 day rolling averages in lieu of the BART Guideline to use 24-hour maximum emissions. The 24-hour maximum value is the highest average of 1-hour values for the same day. The 30-day rolling average is the average of the past 30 operating days' emissions. Both values cover the emissions over a specific data set which consider both high and low values during a period. However, since the 30-day rolling average accounts for a larger portion of time, it is less likely to be heavily influenced by unusual circumstances or conditions.

C. **Comment:** "PNM also erred by assuming that future 24-hour maximum emissions would be the same as the longer-term emission limits. Even though no additional SO_2 control measures are proposed, PNM has assumed that SO_2 emissions will be reduced by one-third from the "baseline" condition. PNM should model future maximum 24-hour emission based upon application of expected improved control efficiencies to the actual baseline emissions from CAM data."

Response: San Juan ultimately must comply with the emission limit in San Juan's air permit, and the SO_2 emissions included in the BART modeling are representative of

both the current permit condition as well as PNM's proposed future SO_2 emission limit under the Revised SIP scenario. The baseline scenario assumes an emission rate of 0.15 lb/mmBtu, per the new NSR Permit, and the assumed reduction of 1/3 SO_2 emissions (0.15 lb/mmBtu to 0.10 lb/mmBtu) is based on the Term Sheet agreement between EPA, NMED, and PNM. Should NMED approve the Revised SIP scenario, PNM will, after permit modification, be required to meet this new SO2 emission limit. Additionally, it is important to note that the state of New Mexico participates in the SO_2 emissions trading program, SO_2 emissions reduction are not analyzed for BART.

D. Comment: "The retirement of Units 2 and 3 will reduce the facility annual NOx emissions by an additional 10,550 tons. When added to the controlled emission rate of Units and 1 and 4, total annual NOx emission will be reduced by 12,989 tons.' We are not clear on the bases for the statement above."

Response: In general, Table 6-1 of the 2013 BART Addendum illustrates these reductions. Currently, the San Juan estimated emissions are 21,000 tpy of NOx. The Revised SIP considers the retirement of Units 2 and 3 plus the additional NOx emission reductions from Units 1 and 4 from 0.30 lb/mmBtu through the installation of SNCR technology to 0.23 lb/mmBtu. The estimated emissions of NOx resulting from the Revised SIP scenario is 8,011 tpy. Therefore, the difference between the two scenarios is a reduction of NOx on an annual basis of 12,989 tpy.

E. Comment: "Ammonia slip was not considered in the modeling analysis."

Response: B&V agrees that ammonia slip was not covered in the analysis, but does not consider this a deficiency in the approach or analysis. As stated in the 2013 BART Addendum, B&V followed the EPA's modeling methodology as described in the TSD document included with the EPA FIP. The EPA also does not consider ammonia slip in their analyses. The TSD states that the ammonia slip may be higher than 1ppb (from SCR's); but that they don't believe it would significantly impact visibility improvements due to reductions in NOx and SO_2 at the San Juan. Ammonia slip from SNCRs is generally more than that for SCRs due to the difference in technology for reduction of NOx, but a significant portion of the ammonia that exits of the SNCR is not expected to be exhausted to atmosphere. It is important to note that the ambient atmosphere contains a variable amount of background ammonia. For the 2013 BART Addendum, it was conservatively assumed that the ambient background concentration of ammonia was constant at 1 ppb—this also followed EPA's modeling methodology.

VII. Conclusion

For all the additional NO_x control technologies evaluated, the resultant cost-effectiveness clearly shows that on a facility-wide basis the Revised SIP is the most cost effective scenario at $1,049/ton verses the 2011 SIP at $5,561/ton and the EPA FIP at $6,218/ton. Additionally, the

visibility analysis indicates that the EPA FIP and Revised SIP scenarios result in similar visibility impacts at the 16 Class I areas analyzed as compared to the 2011 SIP scenario which includes the four SNCRs. Specifically, these two scenarios have greater visibility improvement from the Baseline scenario than the 2011 SIP scenario. The visibility impacts from the Revised SIP at five Class I areas are equal to or better than visibility impacts projected for the EPA FIP scenario and remaining Class I area impacts are less than a 0.5 dv difference. Furthermore, the frequency of the predicted impacts for the average and maximum days over a 0.5 dv and 1.0 dv threshold indicate for the Revised SIP that approximately half or more of the number of Class I areas are comparable to the predicted impacts for the EPA FIP.

Additionally, as shown above in Table 14, the maximum modeled visibility improvement for each BART control technology scenarios at each of the 16 Federal Class I areas was used for the determination of the visibility improvement cost-effectiveness in $/deciview ($/dv). The Revised SIP scenario results in the least cost option for the resulting comparable visibility improvement to the EPA FIP scenario.

AFFIDAVIT OF KYLE J. LUCAS

STATE OF Kansas)
)
)
COUNTY OF Johnson)

I, Kyle J. Lucas, Project Manager for Black & Veatch Corporation, upon being duly sworn according to law under oath, deposes and states: I have read the foregoing testimony and it is true and accurate based on my own personal knowledge and belief.

Signed this 15 day of August 2013

Kyle J. Lucas

Subscribed and sworn to me this 15 day of August 2013.

Deborah L Monter
Notary Public

My Commission Expires:

DEBORAH L. MONTER
STATE OF KANSAS
My Appt. Exp. 9-2-13

DEBORAH L. MONTER
NOTARY PUBLIC
STATE OF KANSAS

Kyle J. Lucas

Kyle Lucas is a Project Manager assigned to Black & Veatch's Environmental Services Section of the Power Generation Service Area within Black & Veatch Energy. His current responsibilities include environmental project management encompassing complex plant compliance, air quality control studies, atmospheric air quality impact studies and permit application preparation, Clean Air Act / New Source Review (NSR) compliance, and consulting services related to new and modified power generating plants and industrial facilities.

His primary responsibilities include assisting clients in developing Clean Air Act compliance strategies and managing specific air permitting and licensing projects, particularly for traditional coal-fired power plants and gas/oil combustion turbine power plants. This role has also included air quality control study evaluations. Lucas has dealt with all aspects of the overall air quality licensing process including strategic planning, recommendation of controls and emission limits, proving expert testimony, overseeing the preparation of atmospheric air quality impact studies and preparation of permit applications, participating in client and agency meetings, and writing applicable sections of environmental impact statements as well as studies associated with air quality control equipment, stack exhaust gas, cooling towers, and fugitive source emissions.

Additionally, Lucas has participated in determining how impacts from multi-pollutant legislation can potentially affect Asset Management for electric generating sources. He identified air quality regulatory drivers impacting the value of coal and oil fired facilities and evaluated potential air quality control technology as mitigation options, and the potential economic impact of these drivers. Environmental drivers considered included the multi-pollutant legislation proposals in Congress, new ozone ambient air quality standard, new fine particulate and other national ambient air quality standards, the Mercury and Air Toxic Standard (MATS), and Cross-State Air Pollution Rule (CSAPR), NSPS, NSR/PSD rules, and Best Available Retrofit Technology (BART) analyses. He has participated in various other regulatory studies based on new proposed regulations such as the Effluent Limitation Guidelines, Cooling Water Intake 316(b), and Coal Combustion Residues, retirement planning analyses, and has also provided expert testimony for various regulatory and planning agencies.

PROJECT MANAGER, COMPLIANCE SPECIALIST, CONSULTANT, ENVIRONMENTAL SPECIALIST

Specialization:
Consulting Engineering Services

Education
Bachelors, Atmospheric Science, University of Kansas, 1993

Total Years Experience
19

Joined Black & Veatch
1994

Professional Associations
Air and Waste Management Association
American Meteorological Society

Language Capabilities
English

Selected Presentations & Publications
Please see the end of this document for details.

REPRESENTATIVE PROJECT EXPERIENCE

Combustion Turbine Technology Assessment; San Juan Generating Station; Public Service Company of New Mexico; San Juan County, New Mexico, United States

2013

Project Manager. Managed the combustion turbine technology assessment analysis to replace Units 2 and 3 with approximately 200 MW of natural gas-fired combustion turbine technology. Combustion turbine technologies were evaluated to define planning level cost and

key operating parameters for different combustion turbine technologies and to assess their relative suitability/ feasibility for use. This study was focused on simple cycle peaking power plants based on the latest Commercial combustion turbine offerings and for converting the peaking unit(s) to combined cycle block(s).

Retirement, Decommissioning, and Demolition Study; Confidential Client; Southwestern US, United States
2013
Assistant Project Manager and Study Manager. Managed an engineering assessment to study the cost of retiring up to four coal-fired units. Three specific scenarios were evaluated with varying degree of environmental compliance. Demolition estimates had to consider applicable environmental drivers and the surgical decommissioning and demolition of selected systems, equipment, and structural materials while maintaining operation of the remaining units and common systems for certain scenarios. Efforts for this project included review of a previous decommissioning study, and verification of material quantities, labor costs, pond and impoundment closure estimates, salvage value estimates, and grey market major equipment resale value.

San Juan Generating Station Best Available Retrofit Technology (BART); Public Service Company of New Mexico; New Mexico, United States
2012-Present
Project Manager and Environmental Manager. Managed the BART modeling and compliance activities and assisted with the BART engineering activities for PNM's four BART applicable units at San Juan Station. Duties included initial BART applicability review and compliance strategy, oversight of the BART modeling, and review of the BART engineering analyses and preparation documentation for agency submittal, agency and client contact, testimony preparation and presentation to the New Mexico Environmental Improvement Board.

Maximum Available Control Technology (MACT) Compliance Planning and Technical and Environmental Services; Confidential Client; Southeastern US, United States
2010-2012
Project Manager. Provided compliance planning services for the Utility MACT for three coal-fired units. Services included facilitating compliance and strategy development meetings, development of emissions testing specifications for a detailed emission testing program on all units, conducted pre-bid meetings with emission testing vendors, bid evaluations, contract negotiations, oversight and coordination of emissions testing programs, determination of required air quality control equipment, oversight of associated analysis, reports, and presentation of various project information.

Compliance Planning and Technical and Environmental Services; Confidential Client; Southeastern US, United States
2011-2012
Assistant Project Manager and Environmental Manager. Provided compliance planning services for a small cooperative which included extensive emission testing, review of new air quality control equipment for air compliance, various equipment upgrades and plant modifications for water and waste material compliance, and power generation alternatives. The project was designed to determine the capital and operations and maintenance (O&M) costs of specific AQC retrofits related to environmental scenario compliance planning for future regulatory requirements. Services included facilitating compliance and strategy development meetings, determination of required air quality control equipment, water intake structure modifications, dry ash conversion systems, landfill modifications, oversight and coordination of engineering activities, air dispersion modeling, associated analysis, reports, and presentations.

NAAQS Modeling for 1-hour NOx and SO2; Confidential Client; Southeastern US, United States
2011-2012
Project Manager. Oversaw the ambient air quality impact analysis for a coal fired power plant in the southeastern US. The goal was to demonstrate facility compliance with the new 1-hour NAAQS for NOx and SO2. Additionally, a cumulative SO2 analyses was conducted to determine the potential affect of the facility on the attainment status of the county where it was located as well as the surrounding counties. Duties included calculation of worst-case operation scenarios using the current and future pollution control equipment, multi-state source emissions inventory, and emissions calculations, oversight and coordination of engineering activities, air dispersion modeling, and participation in work groups, agency discussion, associated analysis, reports, and presentations.

MACT Compliance Planning and Technical and Environmental Services; FirstEnergy Corporation; Ohio, Pennsylvania, and West Virginia, United States
2011-2012
Assistant Project Manager and Environmental Manager.
FirstEnergy retained Black & Veatch to conduct a Phase I high level study to determine order-of-magnitude costs for retrofit AQC equipment for 20 units in its coal fired fleet to comply with various regulatory drivers. Following the study, Black & Veatch developed Phase II project definitions consisting of a conceptual design and budgetary cost estimates for selected AQC technology improvements at eight FirstEnergy's coal fired facilities (Bay Shore, Sammis, Pleasants, Bruce Mansfield, Hatfield's Ferry, Mitchell, Fort Martin, and Harrison

Stations). The project was designed to determine the capital and operations and maintenance (O&M) costs of specific AQC retrofits related to the MATS requirements.

San Juan Generating Station; Public Service Company of New Mexico; Farmington, New Mexico, United States
2007-2012
Assistant Project Manager and Environmental Manager. Managed the BART modeling activities and assisted with the BART engineering activities for PNM's four BART applicable units at San Juan Station. Duties included initial BART applicability review and compliance strategy, oversight of the BART modeling, and review of the BART engineering analyses and preparation documentation for agency submittal, agency and client contact. Also provided expert testimony at the New Mexico Environmental Improvement Board hearing on the state's implementation plans for the San Juan Station's BART and the states interstate transport of pollutants.

Title III Risk Management Program Development and Compliance Audits; Various Clients; Various Locations, United States
2002-Present
Project Manager. Facilitated more than 40 PHA and RMP compliance audits as a team leader for various power generation, water, and wastewater utilities, pursuant to USEPA's Chemical Accidental Prevention Provisions regulations.

Due Diligence; Various Clients; Various Confidential Locations, Global
1994-Present
Air Permitting Manager. Performed due diligence reviews of air permits including construction, operation, and acid rain, as well as compliance histories of numerous facilities located throughout the United States. These studies were part of a larger economic and environmental due diligence study for financing entities. These environmental due diligence reviews were requested for various purposes including potential sale / purchase of facilities, internal compliance audits, and / or refinancing of loans.

Duties included client (bank), operator, and corporate office personnel contact, and review of pertinent air permit and environmental documents, and agency determinations as compared to facility permitted levels and operating emission levels. Verbal and written summary reports were also reviewed and compared to applicable documents. Summary reports were prepared and included with the overall project findings for the financial review.

Compliance Planning and Technical and Environmental Services; Confidential Client; Southeastern US, United States
2011-2012
Assistant Project Manager and Environmental Manager. Provided compliance planning services for a small cooperative, which included

extensive emission testing, review of new AQC equipment for air compliance, various equipment upgrades and plant modifications for water and waste material compliance, and power generation alternatives. The project was designed to determine the capital and O&M costs of specific AQC retrofits related to environmental scenario compliance planning for future regulatory requirements. Services included facilitating compliance and strategy development meetings, determination of required AQC equipment, water intake structure modifications, dry ash conversion systems, landfill modifications, oversight and coordination of engineering activities, air dispersion modeling, associated analysis, reports, and presentations.

MACT Compliance Planning and Technical and Environmental Services; Confidential Client; Southeastern US, United States
2010-2012

Project Manager. Provided compliance planning services for the Utility MACT for three coal fired units. Services included facilitating compliance and strategy development meetings; developing emissions testing specifications for a detailed emission testing program on all units; and conducting prebid meetings with emission testing vendors, bid evaluations, contract negotiations, oversight and coordination of emissions testing programs, determination of required AQC equipment, oversight of associated analysis, reports, and presentations of various project information.

Selective Catalytic Reduction (SCR) Performance Testing; Charles R. Lowman Power Plant; PowerSouth Energy Cooperative, Inc.; Leroy, Alabama, United States
2011-2011

Project Manager. Provided emissions testing oversight services for the two SCR catalyst replacement projects. Services included coordination and development of emissions testing specifications with the catalyst vendor's contract, conducting prebid meetings with emission testing vendors, bid evaluations, contract negotiations, oversight and coordination of catalyst testing program, and oversight of associated analysis and reports.

AQC Study and Budgetary Cost Estimate; Louisville Gas and Electric Company (LG&E) / Kentucky Utilities Company (KU) (PPL); Kentucky, United States
2010-2011

Assistant Project Manager and Environmental Manager. LG&E / KU retained Black & Veatch to conduct a Phase I high level study to determine order-of-magnitude costs for retrofit AQC equipment for 18 units in their coal fired fleet to comply with various regulatory drivers. Following the study, Black & Veatch developed Phase II project definitions consisting of a conceptual design and budgetary cost estimates for selected AQC technology improvements at three of LG&E / KU's coal fired facilities (Mill Creek, Ghent, and Brown). The project was designed to determine the capital and O&M costs of specific AQC retrofits related to environmental scenario compliance planning for

future regulatory requirements.

PSD Air Permitting Services, Holcomb Generating Station; Tri-State Generation & Transmission Inc. and Sunflower Electric Power Corporation; Holcomb, Kansas, United States
2005-2011
Air Permitting Manager. Black & Veatch was retained as Owner's Engineer for the proposed 2,100 MW (3 x 700 MW) coal fired addition. Duties included review of emission calculations, BACT analysis, air modeling and other associated analysis and documents for the air permit activities. Details from the air permitting were applied to associated project equipment and vendor contracts and specifications. Additionally, assisted in post submittal activities which included response to public (Sierra Club) and agency comments.

NSR / PSD Air Permitting Services; Ghent Generating Station, Units 1-4; LG&E; Ghent, Kentucky, United States
2010
Project Manager. Performed a BACT review for sulfuric acid mist (H2SO4) to support the response effort to the 2009 Notice of Violation (NOV) issued by USEPA on March 19, 2009. The NOV indicated coincidental increases of H2SO4, exceeded the NSR PSD Significant Emission Rates (SERs) and were not quantified in the application process for the Unit 1, 3, and 4 SCRs. The BACT scenario reflected operating scenarios consistent with operations and installation of AQC equipment in 2013. Additionally, detailed emission calculations were conducted for the BACT process, as well as for three other scenarios that defined unit operations during various phases of AQC installations (i.e., Pre-2005, 2005, and current operations). Furthermore, a H2SO4 white paper was developed reviewing the complexities of testing and potential errors in the testing methods. Other duties included strategy development, client consultation, review of associated data for particulate emissions and opacity, and client discussions.

BART Analysis and Technical Support; Navajo Generating Station (NGS); Central Arizona Water Conservation District (CAWCD); Arizona, United States
2009-2010
Project Manager. Managed the BART review and technical support activities and assisted CAWCD in the development and preparation of public comments in response to an Advance Notice of Public Rulemaking (ANPR) (74 FR 44313) issued by the USEPA on August 28, 2009, specifically with regard to NGS. Duties included review of applicable NGS BART modeling and engineering studies, and review of Arizona and USEPA comments and technical discussions, development of responses to support CAWCD's ANPR submittal, and presentation of information to CAWCD Board.

BART Modeling Analyses; Charles R. Lowman Power Station; Associated Electric Cooperative (AEC); Leroy, Alabama, United States
2006-2010
Air Permitting Manager. Managed the BART modeling activities for AEC's three BART applicable units. Duties included initial BART applicability modeling and BART permitting strategy, review of the VISTAS BART protocols and associated analyses, gathering of appropriate source information, and preparation documentation for agency submittal and agency and client contact.

NSR / PSD Air Permitting Services; LG&E; Kentucky, United States
2009-2009
Project Manager. Performed a BACT review for H2SO4 to support KU's submittal of PSD / Title V Permit Modification for the addition of SCR for E.W. Brown Unit 3 submitted to Kentucky Division for Air Quality (KDAQ) in July 2009. This was a complex BACT as technology review and the associated emission levels Unit 3 need to consider a retrofit verses installation of a new unit. Other duties included strategy development, client consultation, review of associated data for particulate emissions and opacity, client and agency discussion, and development of several postsubmittal responses to agency Notice of Deficiency requests.

Air Permitting Services; Confidential Client; Southeastern US, United States
2009
Air Permitting Manager. Managed the air-related feasibility and permitting studies for a proposed 1,000 MW coal fired generation at a greenfield location. Additionally, work consisted of Class I & II analyses using both CALPUFF and AERMOD, while other duties included reviewing the generation of engineering design and performance information for use in the analysis, review of BACT emissions limits, AQC technology assessment, emission calculations, and development of permitting strategy.

Technical and Environmental Due Diligence Services; Confidential Client; Eastern Midwest, United States
2009
Air Permitting Manager. Provided additional due diligence assessment and various updates related to certain environmental and technical performance aspects of the study assets. This information was added as an addendum to the original due diligence report Black & Veatch issued in fall 2008.

BART Modeling and Engineering Analyses: Laramie River Generating Station; Basin Electric Power Cooperative; Wheatland, Wyoming, United States
2006-2009
Air Permitting Manager. Managed the BART modeling activities and

assisted with the BART engineering activities for Basin's three BART applicable units at Laramie River Station. Duties included initial BART applicability review and compliance strategy, oversight of the BART Modeling, and review of the BART engineering analyses and preparation documentation for agency submittal, agency, and client contact.

BACT Update; NSR / PSD Air Permitting Services; Trimble County Generating Station Unit 2 Auxiliary Boiler; E.ON US; Trimble County, Kentucky, United States
2008

Project Manager. During the review of the Title V renewal application in December 2007, KDAQ determined that the vacatur of the Industrial Boiler MACT justified a review of the auxiliary boiler's BACT requirements. Although BACT reevaluation analyses are not required as part of a Title V renewal application and the aforementioned Trimble County Unit 2 Project auxiliary boiler had already been constructed, an updated BACT review to demonstrate that the auxiliary boiler as installed represents BACT. The project consisted of conducting a regulatory review, performing a BACT and Industrial Boiler MACT analysis, emission calculations, agency discussions, development of an application document, and agency discussions.

Technical and Environmental Due Diligence Services; Confidential Client; Eastern Midwest, United States
2008

Air Permitting Manager. Performed an air quality environmental due diligence review for 10 facilities consisting of coal fired units, hydro facilities, and combustion turbine installations as part of a larger technical due diligence. This activity consisted in review of available permits, internal operational and compliance documentation, agency determinations as compared to facility permitted levels, operating emission levels, and external public information. Duties also included discussion of potential compliance issues with the client.

Trimble County Generating Station; Louisville Gas & Electric Company (LG&E); Bedford, Kentucky, United States
2006-2008

Project Manager. Tracked design modifications to the proposed 750 MW project during engineering design and construction that were not reflected in the 2004 air permit application or the resulting final air permit. The plant modifications were analyzed and included in an amended air permit application for the facility. Detailed emission calculations, regulatory review, and cumulative source modeling was completed. At the request of the KDAQ air agency, a draft permit and Statement of Basis was developed that reflected the amended application document. Reviewed public and agency comments on the application and draft air permit and drafted responses to comments.

PSD Air Permitting Services, Sutherland Generating Station; Interstate Power and Light Co.; Marshalltown, Iowa, United States
2007

Air Permitting Manager. Assisted with the feasibility analyses and air permitting activities for a proposed 600 MW supercritical pulverized coal fired unit addition the existing Sutherland Generating Station in central Iowa. Duties included assessing Class II criteria pollutant impacts, emissions and visibility calculations, preparation of the BACT analysis, permitting strategy, supervision of air dispersion modeling, review of engineering design and performance information, and preparation of PSD air permit application document. Also, responsible for contact and coordination of activities with the client and state permitting agencies.

BART Modeling Analyses: Cane Run, Mill Creek, Ghent, and E.W. Brown Generating Stations; Louisville Gas & Electric; Kentucky, United States
2006-2007

Project Manager. Managed the BART modeling and engineering activities for LG&E's 10 BART applicable units at four generating stations. The project was able to exempt three facilities and six units from BART requirements and conducted engineering and modeling studies for four units at the Mill Creek Generating Station. Duties included initial BART applicability modeling and BART permitting strategy, review of the VISTAS BART protocols and associated analyses, gathering of appropriate source information, and preparation documentation for agency submittal, agency and client contact.

Air Permitting Services; Confidential Client; Southeast, United States
2006-2007

Air Permitting Manager. Managed the air siting and feasibility studies for a proposed 1,000 MW coal fired or integrated gasification combined cycle (IGCC) generation addition and 480 MW of simple cycle combustion turbine generation at multiple new greenfield and existing facility locations. The coal fired addition included four fuel options and three boiler technologies and associated AQC equipment, while the turbine study focused on four fast-start turbine models. Additionally, the siting study consisted of Class I and II analyses using both CALPUFF and AERMOD, a proximity scoring system to appropriately rank each proposed site. The study focused on 10 coal / IGCC and 13 simple cycle candidate sites. Other duties included a review of the generation of engineering design and performance information for use in the analysis, review of BACT emissions limits, AQC technology assessment, emissions calculations, and development of permitting strategy.

NSR / PSD Air Permitting Services; Permit Appeal, and Litigation Support; Trimble County Generating Station Unit 2; Louisville Gas & Electric Company (LG&E); Trimble County, Kentucky, United States
2005-2007

Project Manager. Assisted LG&E in the Unit 2 air permit appeal process for the air application that was submitted in December 2004. Additionally, supported the litigation activities initiated by Sierra Club and other environmental groups. Duties included responding to agency and public comments, developing strategy, review of other similar permits and responses, conducting additional air analyses as required to support the application and response package, developing testimony, and providing deposition in support of the air permit application and Unit 2 project.

PSD Air Permitting Services, Charles R. Lowman Generating Station; Alabama Electric Cooperative, Inc.; Leroy, Alabama, United States
2004-2006

Air Permitting Manager. Managed the air permitting activities for AEC's air pollution control project at its coal fired plant. The project was permitted under the Alabama PSD air rules under provisions for "Environmentally Beneficial Activities." Duties included initial feasibility studies and permitting strategy, preparation of an air permit application, as well as development of representative operating scenarios and modeling parameters, agency and client contact, and supervision of complex air dispersion modeling analyses.

PSD Air Permitting Services; Trimble County Generating Station; Louisville Gas & Electric Company (LG&E); Bedford, Kentucky, United States
2003-2005

Project Manager. Managed the feasibility analyses and air permitting activities for a proposed 750 MW supercritical pulverized coal fired unit addition for the existing Trimble County Generating Station in northern Kentucky. Duties included assessing Class II criteria pollutant impacts as well as conducting class I analyses, netting analyses, emissions and visibility calculations, preparation of the MACT and BACT analysis, permitting strategy, supervision of air dispersion modeling, review of engineering design and performance information, and preparation of PSD air permit and combined Title V application document. Also, responsible for contact and coordination of activities with the client, subcontractors, state and federal permitting agencies, and U.S. National Park Service. Post-submittal activities included drafting both the air construction and operating permit, agency negotiation, response to public and agency comments, and support through litigation with the Sierra Club, including responses to interrogatories, depositions, and expert testimony. Additionally, oversaw the air permitting activities for design optimizations during construction activities and follow-up activities with the state agency including drafting both the air construction and operating permit.

SELECTED PRESENTATIONS & PUBLICATIONS

Lucas, Kyle J. "University of Missouri Kansas City." Air Emission Requirements Section of ME 454 Mechanical engineering course through UMKC, Black & Veatch P-Building. March 2013.

Lucas, Kyle J. "University of Missouri Kansas City." Air Emission Requirements Section of ME 454 Mechanical engineering course through UMKC, Black & Veatch P-Building. March 2012.

Lucas, Kyle J. "Expert Testimony at New Mexico's Environmental Improvement Board Hearing." Albuquerque and Farmington, New Mexico. June 2011.

Lucas, Kyle J. "University of Missouri Kansas City." Air Emission Requirements Section of ME 454 Mechanical engineering course through UMKC, Black & Veatch P-Building. March 2011.

Lucas, Kyle J. "University of Missouri Kansas City." Air Emission Requirements Section of ME 454 Mechanical engineering course through UMKC, Black & Veatch P-Building. March 2010.

Lucas, Kyle J. "Emissions Control Costs for Low NOx Combustion and Selective Catalytic Reduction." Phoenix, Arizona. February 2010.

Lucas, Kyle J. "The new EPA has promised that "the environmental cop will be back on the beat." What to expect from EPA's vow to aggressively pursue environmental enforcement." EH&S Brownbag. August 2009.

Lucas, Kyle J. "Risk Management Plan Technical Training." City of Wichita, Kansas Water Treatment Plant, City of Wichita, Kansas Water Treatment Plant. August 2009.

Lucas, Kyle J. "A brief summary of little-known facts in compliance obligations for Risk Management Plans (40 CFR Part 68)." 17th Annual Environmental Conference at the Lake Sponsored by Association of Missouri Electric Cooperatives and the Missouri Chamber of Commerce and Industry, Osage Beach, Missouri. July 2009.

Lucas, Kyle J. "University of Missouri Kansas City." Air Emission Requirements Section of ME 454 Mechanical engineering course through UMKC, Black & Veatch P-Building. March 2009.

Lucas, Kyle J. "University of Missouri Kansas City." Air Emission Requirements Section of ME 454 engineering course through UMKC, Black & Veatch P-Building. March 2008.

Lucas, Kyle J. "Fossil Fuel Power Plant Siting." EH&S Brownbag Session 11. September 2007.

Lucas, Kyle J. "University of Missouri Kansas City." Air Emission Requirements Section of ME 454 engineering course through UMKC, Black & Veatch P-Building. March 2007.

Lucas, Kyle J. "Regional Haze and Best Available Retrofit Technology (BART) Roundtable Brownbag." Black & Veatch Brownbag. January 2006.

Lucas, Kyle J. "Risk Management Plan Technical Training." City of Flagstaff, Arizona Wildcat Hill Wastewater Treatment Plant. May 2005.

Lucas, Kyle J. and Tim Hillman. "Risk Management Plan Certifications - An On-going Effort." Black & Veatch Technology Transfer Session, Black & Veatch Water Office. May 2005.

Lucas, Kyle J.; Jeff Arroyo and Rick Lausman. "Multi-pollutant Compliance Planning: Recent Findings and Conclusions." POWER-GEN 2004, Orlando, Florida. December 2004.

Lucas, Kyle J. "Regional Haze Overview." Black & Veatch. May 2002.

Lucas, Kyle J. "Air Permitting Coal-Fired Power Plants, Overview and Critical Issues." Black & Veatch. April 2002.

Lucas, Kyle J. "Presented expert testimony for air quality related issues for the Prevention of Significant Deterioration Air Permit Application for the Orlando Utilities Commission's Curtis H. Stanton Energy Center Combined Cycle Addition at the State of Florida's Site Certification Application (SCA)." SCA Public Hearing, Public Hearing Orlando, Florida. June 2001.

Lucas, Kyle J. "Cooling Towers, Visible Water Vapor Plume from Combustion Sources, and Regional Haze Analyses." Black & Veatch. September 2000.

Lucas, Kyle J. "Introduction to the Cooling Tower Model - SACTI." Black & Veatch. June 2000.

Lucas, Kyle J. "Preparation of an Air Dispersion Modeling Protocol." Black & Veatch. October 1999.

Lucas, Kyle J. and Dan Wilkus. "A Proven Seven-Step Process for Assembling an 'Administratively Complete' Title V Permit Application." Air & Waste Management Association Midwest Section's 1996 Technical Conference, Kansas City. September 1996.

Lucas, Kyle J. and Dan Wilkus. "Seven Steps to Obtaining an 'Administratively Complete' Title V Permit Application." Air & Waste Management Association. January 1996.

AFFIDAVIT OF DIANE FISCHER

STATE OF KANSAS)
)
)
COUNTY OF JOHNSON)

I, Diane Fischer, Air Quality Control Services Area Leader for Black & Veatch Corporation, upon being duly sworn according to law under oath, deposes and states: I have read the foregoing testimony and it is true and accurate based on my own personal knowledge and belief.

Signed this 16 day of August 2013

Diane Fischer

Subscribed and sworn to me this 16 day of August 2013.

Deborah L. Monter
Notary Public

My Commission Expires:

DEBORAH L. MONTER
STATE OF KANSAS
My Appt. Exp. 9-2-13

DEBORAH L. MONTER
NOTARY PUBLIC
STATE OF KANSAS

Diane M. Fischer

Diane M. Fischer is a Services Area Leader within Black & Veatch's global energy business. She is primarily involved with air quality control (AQC) compliance projects. Her duties include coordinating business development, establishing budgets, developing and maintaining standard tools for AQC studies, and monitoring project execution. She also manages compliance studies, supports detailed design of AQC projects, and maintains updated knowledge of the regulations associated with air quality compliance:

- Mercury and Air Toxics Standards (MATS).
- Boiler Maximum Achievable Control Technology (MACT).
- National Ambient Air Quality Standards (NAAQS).
- New Source Review (NSR).
- Regional Haze.

REPRESENTATIVE PROJECT EXPERIENCE

AQC Services Area; Overland Park, Kansas, United States
2011-Present

Services Area Leader. Responsible for oversight of AQC Services, which includes evaluation of emissions control technology applications for the energy industry, including technology selection, emissions compliance strategy development, and performance improvements for existing AQC equipment.

Environmental Management; Kansas City Board of Public Utilities (BPU); Kansas City, Kansas, United States
2011-2012

Air Quality Control Engineer. Black & Veatch provided BPU with consulting services associated with complying with Cross-State Air Pollution Rule (CSAPR), MATS, NAAQS, 316b, and coal combustion residuals (CCR) regulations. This analysis included developing AQC alternatives, assessing power and fuel alternatives, and developing conceptual designs for compliance alternatives.

La Cygne Station AQC Retrofit; Kansas City Power & Light; La Cygne, Kansas, United States
2010-2012

Air Quality Control Engineer. Responsible for the development, bid evaluation, and bid negotiation associated with the selective catalytic reduction (SCR) portion of the engineering, procurement, and construction (EPC) specification for new AQC equipment at La Cygne Units 1 and 2.

PROJECT MANAGER

Specialization:
Air Quality Control

Education
Bachelors, Mechanical Engineering, Iowa State University, 1992

Professional Registration
2012, Missouri, Professional Engineering License - Renewal (Original Issued in 1996), EN 028199

Total Years Experience
20

Joined Black & Veatch
1992

Language Capabilities
English

Selected Presentations & Publications
Please see the end of this document for details.

Best Available Retrofit Technology (BART) Analysis; Public Service of New Mexico; New Mexico, United States
2007-2012
Project Manager. Responsible for engineering work on a BART analysis for four coal fired power plants. The analysis examined BART alternatives for nitrogen oxides (NOx) and particulate matter. This study was done in response to the federal Regional Haze requirements.

Asbury Station Environmental Retrofit Project Definition; Empire District Electric Company; Joplin, Missouri, United States
2010-2010
Air Quality Control Engineer. Black & Veatch performed a study to determine the recommended AQC equipment for Asbury Station to comply with potential air emissions regulations. Fischer was responsible for all process-related activities for the project, including air quality equipment selection, development of cost estimates for AQC equipment, mass balances, and identification of redundancy and sizing requirements.

Boilers 8 and 9 NOx Reduction Project; Hovensa; St. Croix, Virgin Islands (U.S.)
2009-2010
Air Quality Control Engineer. Black & Veatch assisted Hovensa in developing a conceptual design for the retrofit of SCR systems on two refinery gas / No. 6 fuel oil fired boilers. The project included obtaining budgetary estimates for all equipment, developing layout drawings, developing system descriptions, and developing flow diagrams. The project also included developing a specification for purchase of the SCR system.

New Biomass Fired Boiler; Oglethorpe Power Corporation (OPC); Georgia, United States
2008-2010
Air Quality Control Engineer. Black & Veatch assisted OPC in obtaining permitting for two 100 MW biomass fired boilers in Georgia. Support of the permitting included emissions calculations and AQC technology assessment. Black & Veatch continued to support OPC in the procurement of the boiler and AQC equipment through development of the specifications and bid evaluation.

NOx Reduction Study; Entergy; Lake Charles, Louisiana, United States
2009-2009
Project Manager. Black & Veatch performed a NOx reduction study that examined NOx reduction technologies for one Powder River Basin (PRB) fired power plant.

Preliminary Engineering for AQC Equipment; TransAlta Utilities Corporation; Alberta, Canada
2008-2009
Engineering Manager. Black & Veatch performed a preliminary engineering assessment to determine the feasibility, layout, and balance-of-plant impacts of a retrofit of the spray dryer absorbers and fabric filters for six coal fired units in Alberta, Canada. The project included obtaining budgetary estimates for all equipment, developing layout drawings, developing system descriptions, and developing flow diagrams.

Mercury Technology Assessment Study; Platte River Power Authority; Colorado, United States
2007-2009
Project Manager. Responsible for the assessment of available mercury control technologies for four coal fired power plants. The study included identifying potential technologies, developing budgetary costs, and determining the recommended technology. Based on the results of the study, Black & Veatch develop a specification for purchase of the mercury control equipment and assisted the client in evaluating the vendor proposals.

SCR Retrofit Project; Saint Johns River Power Park; Florida, United States
2006-2009
SCR Technical Manager. Responsible for the process design associated with installing SCR systems on two coal fired boilers. Duties included oversight of the development of catalyst specification, ductwork design, flow model testing, startup, and performance testing.

SCR Retrofit Project; Alabama Electric Cooperative; Alabama, United States
2005-2008
SCR Technical Manager. Responsible for the process design associated with installing SCR systems on two coal fired boilers.

New Coal Fired Power Plant; Wisconsin Public Service Company; Wisconsin, United States
2003-2008
AQC Engineer. Responsible for providing process design support associated with installing an SCR system on a new coal fired boiler, including contract negotiations and design review.

Mercury Technology Assessment Study; Xcel Energy; Minnesota, United States
2007-2007
Project Manager. Responsible for the assessment of available mercury control technologies for four coal fired power plants. The study included characterizing existing mercury emissions, identifying potential technologies, developing budgetary costs, and determining the recommended technology.

Multi-Pollutant Study; TransAlta Utilities; Alberta, Canada
2006-2007
Project Manager. Responsible for the economic analysis of AQC alternatives available for eight coal fired power plants. Study included assessment of available technologies for removing sulfur dioxide (SO2), NOx, particulate matter, mercury, and carbon dioxide (CO2). From the results of the study, an Excel spreadsheet was developed that allowed the owner to change control alternatives according to changes to regulations.

King Plant Rehabilitation Project; Xcel Energy; Minnesota, United States
2004-2007
AQC Engineer. Responsible for providing process design support associated with installing an SCR system as part of a rehabilitation of a 600 MW coal fired boiler, including contract negotiations and design review.

SCR Retrofit Projects; Vectren; Indiana, United States
2000-2005
SCR Technical Manager. Responsible for the process design associated with installing SCR systems on four coal fired boilers.

SCR Retrofit Projects; Northern Indiana Public Service Company (NIPSCO); Indiana, United States
1999-2005
Mechanical Engineer. Responsible for the process design associated with installing SCR systems for four coal fired boilers.

Flue Gas Conditioning Study; Allegheny Energy; Pennsylvania, United States
2004-2004
Project Manager. Performed a cost comparison study of flue gas conditioning alternatives for three 555 MW units.

SCR Retrofit; Dayton Power & Light; Ohio, United States
1999-2004
Mechanical Engineer. Responsible for detailed design of AQC system-related equipment including catalyst, dampers, ash handling, flue gas conditioning, and NOx monitoring equipment for retrofit of SCR systems at five 600 MW coal fired boilers.

NOx and SO2 Emissions Reduction Preliminary Engineering Study; Confidential Client; Confidential Location, United States
2003-2003
AQC Engineering Manager. Directed the process analysis and design work associated with the AQC process design. The preliminary engineering project included preliminary design of SCR systems and SO2 reduction using sorbent injection.

SCR Retrofit Project; City of Springfield, Illinois; Illinois, United States
2001-2003
SCR Technical Manager. Responsible for the process design associated with installing SCR systems on three coal fired boilers.

SO2 Emissions Reduction Study; Confidential Client; Confidential Location, Other
2002-2002
AQC Engineer. Assisted in the feasibility study of SO2 reduction alternatives, specifically dry sorbent injection.

NOx Reduction Consulting Services; Confidential Client; Illinois and Indiana, United States
2001-2002
Project Manager. Responsible for the overall project, which consisted of providing technical support regarding NOx reduction technologies to the client as it considered power purchase agreements with several coal fired power plants.

Flue Gas Desulfurization (FGD) Retrofit Study; Confidential Client; Ohio, United States
2001-2001
Project Manager. Responsible for overall conceptual design and the final report. A conceptual design and cost estimate was developed for retrofitting FGD equipment on a 610 MW coal fired boiler.

NOx Compliance Study; NIPSCO; Indiana, United States
1998-1998
Mechanical Engineer. Assisted in a NOx compliance study to examine NOx reduction technologies for seven different units.

NOx Compliance Study; City of Holland; Holland, Michigan, United States
1998-1998
Mechanical Engineer. Assisted in a NOx compliance study to examine NOx reduction alternatives and provide recommendations based on the current regulatory environment.

Material Handling Study; Iowa State University; Ames, Iowa, United States
1998-1998
Mechanical Engineer. Assisted with a material handling study to determine improved material handling systems for the facility.

910 Project; Union Camp Corporation; Franklin, Virginia, United States
1996-1998
Mechanical Engineer. Assisted with startup and project closeout issues related to AQC equipment, continuous emissions monitoring system (CEMS) equipment, and emissions testing.

West Java Power Plant; Ansaldo Engergia S.p.A.; West Java, Indonesia
1997-1997
Mechanical Engineer. Responsible for design and specification of FGD and particulate removal systems, ash handling, and CEMS equipment for a 400 MW coal fired boiler.

Southpoint Project; Calpine; Arizona, United States
1997-1997
Mechanical Engineer. Assisted in permitting for a new natural gas fired combined cycle project. Project included detailed review of emerging NOx reduction technologies.

Lightweight Aggregate Plant; Wisconsin Electric Power Company; Wisconsin, United States
1997-1997
Mechanical Engineer. Assisted in examining causes of benzene and acrylonitrile emissions at a sludge incinerating facility and assisted in determining AQC solutions.

NOx Compliance Study; Allegheny Power Systems; Pennsylvania and West Virginia, United States
1997-1997
Mechanical Engineer. Assisted in a NOx compliance study to examine NOx reduction technologies for 11 different units.

Big Cajun II; Cajun Electric Cooperative; New Roads, Louisiana, United States
1995-1997
Mechanical Engineer. Involved with specification and design of an economizer ash handling system.

Big Cajun II; Cajun Electric Cooperative; New Roads, Louisiana, United States
1996-1996
Mechanical Engineer. Completed a 6 week on-site construction management assignment for construction of economizer ash handling systems on two units.

Independent Power Producer (IPP) Combined Cycle Project; Dongbu Engineering and Construction Co.; Unknown Location, Korea
1996-1996
Mechanical Engineer. Assisted in developing the mechanical portions of a proposal. Involvement included piping and instrumentation diagrams (P&IDs), system descriptions, and bill of quantities.

Iatan 2; Iatan Power Partners; Missouri, United States
1995-1996
Mechanical Engineer. Assisted in obtaining permitting for a new, pulverized coal fueled boiler.

Fisk and Waukegan Stations; Commonwealth Edison Company; Chicago, Illinois, United States
1994-1996
Mechanical Engineer. Specified, designed, and administered contracts for ash handling systems.

Joppa Station; Electric Energy Inc.; Joppa, Illinois, United States
1993-1995
Mechanical Engineer. Involved with specification and design of fly ash handling systems.

Silas Ray Repowering Project; City of Brownsville; Brownsville, Texas, United States
1994-1994
Mechanical Engineer. Assisted in obtaining permitting for a new natural gas and fuel oil fired combustion turbine.

Cheswick and Elrama Stations; Duquesne Light Company; Pennsylvania, United States
1993-1994
Mechanical Engineer. Developed quality control plans and audit plans for newly installed CEMS.

Cedar Bay Cogeneration Plant; Cedar Bay Generating Company; Jacksonville, Florida, United States
1993-1994
Mechanical Engineer. Coordinated air emissions testing activities for demonstration of compliance with the air permit.

Boomer Lake Station; Stillwater Utilities Authority; Stillwater, Oklahoma, United States
1992-1994
Mechanical Engineer. The project involved development of predictive NOx emissions monitoring system. Assisted in specification development, test procedure development, and permit compliance.

Muddy River Energy Project; Muddy River Limited Partnership; Nevada, United States
1993-1993
Mechanical Engineer. Assisted in obtaining permitting for a new natural gas fired combustion turbine.

Coke Oven Gas Boiler; Indianapolis Power and Light; Indiana, United States
1993-1993
Mechanical Engineer. Assisted in obtaining permitting for a new coke oven gas fueled boiler.

Ponca City Steam Plant; Oklahoma Municipal Power Authority; Oklahoma, United States
1993-1993
Mechanical Engineer. Assisted in obtaining permitting for a natural gas and fuel oil fired combustion turbine.

CEMS Specifications; Various Clients; Various Locations, United States
1993-1993
Mechanical Engineer. Assisted in development of several CEMS equipment specifications in response to the 1990 Clean Air Act Amendments; clients and projects included Hastings Utilities, Washington Water Power, Cane Island, and Kissimmee.

Morgantown Units 1 and 2, Chalk Point Units 1 and 2, Dickerson Units 1 - 3; Potomac Electric Power Cooperative; Pennsylvania, United States
1993-1993
Mechanical Engineer. Examined SO2 emissions control alternatives for three power plants.

SELECTED PRESENTATIONS & PUBLICATIONS

Fischer, Diane M. and Preston Tempero. "Early Lessons Learned from Implementation of Dry Sorbent Injection Systems." PowerGen International, Orlando, Florida. December 2012.

Fischer, Diane M. "Developing Holistic Compliance Solutions." Electric Utility and Environment Conference (EUEC), Phoenix, Arizona. January 2012.

Fischer, Diane M. and Mike King. "AQC Equipment Needs for Co-Firing of Alternative Fuels." Council of Industrial Boiler Owners (CIBO) Fluidized Bed Conference, Hershey, Pennsylvania. June 2009.

Fischer, Diane M., Gerald Smith, Noel Rosha, Robert Branning, Kathryn Robinson, Volker Rummenhohl, and John Cochran. "St. Johns River Power Park 2 x 670 MW SCR - Designed to Ensure Fuel Flexibility." EPRI-DOE-EPA Combined Utility Air Pollution Control Symposium (Mega Symposium), Baltimore, Maryland. August 2008.

Fischer, Diane M. "Managing the Utility's Risk from the Permitting Process." EUEC, Tucson, Arizona. January 2008.

Fischer, Diane M. and James Hover of Black & Veatch and David Capozella of Dayton Power & Light. "Unique Design Solutions and Implementation Approach for Dayton Power & Light Killen Station SCR Project." COAL-GEN Conference, Overland Park, Kansas. July 2004.

Fischer, Diane M. "Application of SCR on PRB Fired Units." Western Coal Council, Burning PRB Coal Seminar, Louisville, Kentucky. April 2002.

Fischer, Diane M. and Duane Highley of Associated Electric Cooperative. "Operating Experience with SCR on New Madrid Unit 2, 600 MW PRB-Fired Cyclone Boiler." Association of Rural Electric Cooperatives, 2001 Annual Conference, Clearwater, Florida. June 2001.

Fischer, Diane M., Michael Gregory, John Cochran, and Mickey Harpenau. "The Cost of Complying with NOx Emissions Regulations for Existing Coal Fueled Boilers." EPRI-DOE-EPA Combined Utility Air Pollution Control Symposium (Mega Symposium), EPRI-DOE-EPA Combined Utility Air Pollution Control Symposium (Mega Symposium). August 1997.

EXHIBIT B&V-3 Impact Analysis and Cost-Effectiveness Results of Additional NO_x Control Technologies

IMPACT ANALYSIS AND COST EFFECTIVENESS RESULTS OF NO_x CONTROLS FOR SJGS									
ALL FEASIBLE TECHNOLOGIES	NOx EMISSIONS PERFORMANCE LEVEL (LB/MMBTU)	EXPECTED NOx EMISSION RATE (LB/HR)	EXPECTED NOx EMISSION RATE (TPY)	EXPECTED NOx EMISSION REDUCTION (TPY)	TOTAL CAPITAL INVESTMENT (TCI) (1,000$)	TOTAL ANNUALIZED COST (TAC) (1,000$)	COST EFFECTIVENESS ($/TON)	ENERGY IMPACTS (1,000$)	NON-AIR ENVIRONMENTAL IMPACTS (1,000$)
FEDERAL IMPLEMENTATION PLAN - SCR ALL UNITS									
SJGS 1 - SCR	0.05	185.4	690	3,450	180,862	22,165	6,425	746	--
SJGS 2 - SCR	0.05	184.4	687	3,433	203,360	24,562	7,157	729	--
SJGS 3 - SCR	0.05	287.9	1,072	5,359	264,208	32,585	6,080	1,107	--
SJGS 4 - SCR	0.05	282.5	1,052	5,258	235,940	29,508	5,613	1,102	--
Total		940	3,500	17,500	884,370	108,820	6,218	3,683	
STATE IMPLEMENTATION PLAN - SNCR ALL UNITS									
SJGS 1 - SNCR	0.23	852.6	3,174	966	17,392	5,400	5,590	43	--
SJGS 2 - SNCR	0.23	848.2	3,158	961	17,392	5,400	5,618	43	--
SJGS 3 - SNCR	0.23	1,324.3	4,931	1,501	17,163	8,224	5,480	51	--
SJGS 4 - SNCR	0.23	1,299.3	4,837	1,472	17,163	8,224	5,587	51	--
Total		4,324	16,100	4,900	69,111	27,248	5,561	187	
STATE ALTERNATIVE - SNCR UNITS 1 & 4									
SJGS 1 - SNCR	0.23	852.6	3,174	966	17,392	5,400	5,590	43	--
SJGS 2 - Retire	n/a	n/a	n/a	4,119	n/a	n/a	n/a	n/a	--
SJGS 3 - Retire	n/a	n/a	n/a	6,431	n/a	n/a	n/a	n/a	--
SJGS 4 - SNCR	0.23	1,299.3	4,837	1,472	17,163	8,224	5,587	51	--
Total		2,152	8,011	12,989	34,556	13,624	1,049	94	

Notes:

1. Costs for all technologies are shown in 2013 dollars.
2. Expected emission rates (tpy) calculations were based on 85 percent unit capacity factor.
3. Expected emission reduction (tpy) calculations were based on control effectiveness described in submittal and baseline emissions (refer to June 6, 2007 BART Application Document).
4. Cost-effectiveness ($/ton) is defined as ratio of TAC over Expected Emission Reduction (tpy).
5. Expected emission reduction is based on annual emission reduction from Baseline emission levels technologies.
6. Incremental cost effectiveness are based on increments in expected emission reduction (tpy), but do not apply in this table since technologies are the same.

SOURCE: 2013 BART Addendum

STATE OF NEW MEXICO

ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED REVISIONS TO THE STATE IMPLEMENTATION PLAN FOR THE SAN JUAN GENERATING STATION BEST AVAILABLE RETROFIT TECHNOLOGY DETERMINATION	)))))	NMEIB No. 13-02 (R)

DIRECT TESTIMONY OF SARGENT & LUNDY (DR. RAJENDRA P. GAIKWAD) SUBMITTED ON BEHALF OF PUBLIC SERVICE COMPANY OF NEW MEXICO IN SUPPORT OF PETITION FOR REGULATORY CHANGE

PNM EXHIBIT "D"

I. INTRODUCTION

Sargent & Lundy LLC ("S&L") submits the following testimony on behalf of Public Service Company of New Mexico ("PNM") in this proceeding. The S&L employee providing this testimony is Dr. Rajendra P. Gaikwad, Vice-President of Environmental Services. A copy of Dr. Gaikwad's statement of qualifications is attached hereto as PNM Exhibit SL-1.

S&L is a leading global engineering, design, and consulting company, focused exclusively on the power generating industry. Since its inception in 1891, S&L has remained an independent evaluator of power generating technologies and control systems. S&L is not a vendor of technology or equipment so the company has no vested interest in any technology or system that a utility may use to facilitate the generation of electricity or any technology that may be used to control emissions (e.g., pollution control equipment). S&L's focus has always been on providing consulting services to assist utilities with their generation planning and engineering services to help implement those generation plans. Our history reflects this commitment to be an independent and fair evaluator of the candidate technologies and their ability to meet a utility's ongoing generation needs and compliance objectives.

S&L has considerable experience with the specification, evaluation, selection and implementation of emission control technologies for fossil fuel-fired utility power facilities. With respect to the control of nitrogen oxides ("NOx") emissions from coal-fired power plants, S&L has completed, or is currently in the process of completing, more than 98 projects, representing more than 47,400 MW of generation. Our NOx control experience includes conceptual studies and preparing control system specifications, as well as the engineering, procurement, and installation of various control systems. S&L has participated in the design and installation of more than 26 selective non-catalytic reduction ("SNCR") control systems and more than 72 selective catalytic reduction ("SCR") control systems. In addition, S&L has performed

considerable work with respect to Best Available Retrofit Technology ("BART") controls for coal-fired power plants. Our BART work includes technical feasibility evaluations, cost estimating, cost-effectiveness evaluations and visibility impact modeling. S&L has prepared BART cost estimates determinations for approximately 24 units located at 12 generating facilities.

S&L was retained by PNM to undertake various independent cost analyses of NOx control technologies available to the San Juan Generating Station ("San Juan"). PNM's requests focused on the NOx control technologies identified as BART for the four San Juan units in the State of New Mexico's State Implementation Plan ("SIP") approved by the New Mexico Environmental Improvement Board ("NMEIB") on June 2, 2011, in the U.S. Environmental Protection Agency's ("EPA") Federal Implementation Plan ("FIP") published on August 22, 2011, and in an amended SIP described in the Term Sheet dated February 15, 2013 ("Term Sheet"). The amended SIP is referred to in this testimony as the "Revised SIP." In addition, S&L developed the conceptual design and cost estimates for the SNCR and SCR options. S&L also prepared the Engineer, Procure and Construct ("EPC") specifications for building the SCR project and are currently working with PNM to develop the technical specifications for the SNCR project.

A. Purpose of S&L Testimony

The purpose of S&L's testimony in this proceeding is to provide the NMEIB with an independent and updated cost analysis of the NOx control technologies associated with the EPA FIP, the New Mexico 2011 SIP and the New Mexico Revised SIP, focusing on the costs associated with installing and operating SNCR and SCR control systems. Our written testimony includes a description of the methodology used to develop the control technology cost estimates and a summary of the costs PNM would incur to install and operate the subject NOx control systems. We also address the relative cost effectiveness of each of the technologies considered.

B. Summary of S&L's Testimony

A summary of the total capital costs and direct annual costs associated with the installation, maintenance, and operation of SNCR and SCR control systems on San Juan Units 1, 2, 3 and 4 are provided in Table 1. Estimated costs summarized in Table 1 represent project-specific costs that PNM would incur to install and operate the subject NOx control technologies on San Juan Units 1, 2, 3 and 4. Costs were prepared in accordance with the BART Guidelines published in 40 CFR Part 51 Appendix Y ("BART Guidelines"), following the methodology described in the Office of Air Quality Planning and Standards ("OAQPS") EPA Air Pollution Control Cost Manual, Sixth Edition ("Control Cost Manual"). Capital costs were developed taking into account site-specific design and other conditions affecting the cost of the control systems. Site-specific conditions affecting control technology costs were identified and documented in our report titled "*San Juan Generating Station Units 1, 2, 3 & 4 – SNCR and SCR Cost Estimates, Final Report*, dated March 29, 2013 (the "S&L 2013 Cost Estimate").

The Revised SIP which calls for the shutdown of two units and the installation of SNCRs on the remaining units will result in a capital investment of $34,555,100 and annual direct costs of $10,127,100. EPA's FIP which requires the installation of SCRs on each of the four units at San Juan will result in a capital investment of $884,369,500 and direct annual costs of $26,979,800. It is S&L's opinion that NMED reasonably relied on our project-specific control technology cost estimates in its May 21, 2013 revised BART determination for San Juan.

Table 1
San Juan Generating Station
EPA FIP and Revised SIP
Total Annual Costs and Cost-Effectiveness

Unit	FIP (SCR) Capital Costs	Revised SIP (SNCR) Capital Costs	FIP (SCR) Direct Annual Costs	Revised SIP (SNCR) Direct Annual Costs
1	$180,861,800	$17,391,600	$5,427,900	$3,791,300
2	$203,359,900	$0	$5,742,800	$0
3	$264,207,800	$0	$8,134,700	$0
4	$235,940,000	$17,163,500	$7,674,400	$6,635,800
Total	**$884,369,500**	**$34,555,100**	**$26,979,800**	**$10,127,100**

II. BACKGROUND

The Regional Haze Rule in New Mexico, and the related need for BART controls on San Juan Units 1, 2 3 and 4 has an extensive history. A detailed history of the development of BART controls for San Juan units is provided in testimony filed in this proceeding by NMED and PNM Witness Black & Veatch ("B&V"); therefore, S&L is not providing a description of the development of BART controls for the San Juan units.

On October 25, 2012 PNM engaged the services of S&L to prepare an independent and updated cost estimate of both SNCR and SCR control technologies at San Juan. Updated cost estimates were provided to PNM in the S&L 2013 Cost Estimate. Cost estimates were provided to NMED on April 1, 2013 to support the Department's BART determination for NOx controls on San Juan Units 1 and 4, pursuant to the terms and conditions of the Term Sheet. NMED relied on these cost estimates in its May 21, 2013 revised BART determination for San Juan.[1] The May 21, 2013 document revised an earlier BART determination for San Juan Units 1, 2, 3 and 4, taking into consideration new emissions reductions and economic analysis of three specific control

[1] See, Public Comment Version of *Appendix D: Revised BART Determination*, dated May 21, 2013 and revised June 27, 2013, and revised on June 27, 2013 ("NMED Revised BART Determination").

scenarios, including control scenarios contained in the EPA FIP (SCR controls on all four units); the NM SIP approved by the NMEIB on June 2, 2011 (SNCR controls on all four units); and the Revised SIP which considers the voluntary retirement of San Juan Units 2 and 3 and installation of SNCR on Units 1 and 4.[2]

III. S&L'S NOX CONTROL SYSTEM COST ESTIMATES

The following testimony provides a description of the methodology and assumptions used by S&L to develop the San Juan SNCR and SCR cost estimates, as well as an explanation as to why our approach is consistent with the methodology described in the BART Guidelines and EPA's Control Cost Manual. Control technology costs provided herein are representative of the costs that PNM would incur to install and operate SNCR or SCR controls on the San Juan units and it is appropriate that NMED and the NMEIB rely on these costs to determine BART for NOx control at San Juan.

A. Cost Estimations Under the Regional Haze Rule and BART Guidelines

The BART Guidelines describe the methodology that should be used to determine control system costs and to calculate control system cost-effectiveness. The guidelines describe a three step process to prepare control technology cost estimates: (1) identify the emissions unit being controlled; (2) identify design parameters for emission controls; and (3) develop cost estimates based upon those design parameters.[3] The basis for equipment cost estimates should be documented, either with data supplied by an equipment vendor or by a referenced source such as EPA's Control Cost Manual.[4] The cost analysis should take into account any site-specific design or other conditions that affect the cost of a particular control technology, provided that the cost

[2] NMED Revised BART Determination, page 3.
[3] 70 FR 39166, July 6, 2005.
[4] *Id.*, referencing EPA's OAQPS Air Pollution Control Cost Manual, Sixth Edition, January 2002, EPA\452\B-02-001.

estimate includes documentation of any additional information that was used for the cost calculations that affects assumptions regarding purchased equipment costs, equipment life, replacement of major components, and any other element of the calculation that differs from the Control Cost Manual.[5]

EPA's BART Guidelines specify that the cost impact analysis of the BART determination consider the cost-effectiveness of each control technology on a dollar-per-ton ($/ton) of air pollutant removed. Annual emissions using a particular control device are subtracted from baseline emissions to calculate tons of pollutant controlled per year. Annual costs are calculated by adding the annualized cost of capital to the annual O&M costs of a control option. Cost-effectiveness of an option is simply the total annual cost ($/yr) divided by the annual emission reduction (ton/yr). The Control Cost Manual describes a methodology to calculate the Total Annual Cost ("TAC") associated with an air pollution control system. TAC includes three elements, and is calculated using the following equation:

TAC = DC + IC – RC (Cost Manual, equation 2-1, page 2-7)
Where: DC = direct costs;
IC = indirect costs; and
RC = recovery credits

Direct costs are those that tend to be directly proportional (variable costs) or partially proportional (semi-variable costs) to some measure of productivity (e.g., exhaust gas processed by the control system per unit time). Direct costs include raw materials (reagents), utilities, waste treatment and disposal, maintenance materials, replacement parts, and operating, supervisory and maintenance labor. Indirect or "fixed" annual costs are independent of the level of production and would be incurred even if the control system were shut down. Indirect costs include the capital recovery costs, administrative charges, property taxes and insurance. Recovery credits

[5] See, 70 FR 39166, col. 3, and footnote 15.

account for materials or energy recovered by the control system which may be sold, recycled, or reused to offset the direct and indirect annual costs.

Capital recovery can represent a significant portion of the annual indirect costs, especially on large, capital intensive air pollution control projects. Capital recovery is an annualized cost of capital calculated as an annual payment sufficient to finance total capital costs over the life of the investment. The annualized capital recovery cost is a function of the Total Capital Investment ("TCI"), operational life of the control technology and an appropriate discount interest rate that reflects the financial structure of the applicants business.[6]

TCI includes all costs required to purchase equipment needed for the control system (purchased equipment cost), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and buildings and certain other costs (indirect installation costs).[7] Direct installation costs include costs for foundations and supports, erecting and handling the equipment, electrical work, piping, insulation and painting. Indirect installation costs include costs such as engineering costs; construction and field expenses (i.e., cost for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies. TCI also includes costs for working capital and off-site facilities.[8]

The Control Cost Manual describes a constant dollar approach to calculating total annual costs.[9] The constant dollar approach described in the Control Cost Manual annualizes the costs of installation, maintenance and operation of a pollution control device in constant new present

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[6] See, Control Cost Manual, Section 1, Chapter 2, page 2-21.
[7] *Id.* at page 2-5.
[8] *Id.*
[9] *Id.*

value of dollars over the life of the control system. The Control Cost Manual recommends translating the costs of installation, maintenance and operation of a pollution control device to equal annual payments using an equivalent uniform annual cash flow ("EUAC") method.[10] The methodology can be used to translate all future costs of maintenance and operation into equal annual payments over the life of the control system. The constant dollar approach described in the Control Cost Manual requires that the analyst establish a baseline year from which total costs can be equalized (in constant dollars) over the life of the control system.

Although the Control Cost Manual describes a methodology for calculating total capital costs and total annual costs, it also allows for flexibility to take into consideration project-specific constraints. For example, the Control Cost Manual states that "the user has to be able to exercise 'engineering judgment' on those occasions when the procedures may need to be modified or disregarded,"[11] and that "the application of an appropriate [indirect capital cost] factor requires the subjective application of the analyst's best judgment."[12] In addition, the Control Cost Manual specifically states that for certain control systems, including SCR reactors, it deviates from its standard approach of providing study level costs and, instead, provides a description of the factors that influence TCI for the analyst to consider when dealing with a vendor quotation.[13] The Control Cost Manual takes this approach because "the control in question is either so large or so site-specific in design that suppliers design, fabricate, and construct each control according to the specific needs of the facility."[14]

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[10] *Id*, at page 2-20.
[11] *Id.* at page 1-7.
[12] *Id.* at page 2-28.
[13] *Id.* at page 2-27.
[14] *Id.*

B. Methodology Used to Develop the San Juan SNCR Cost Estimates

S&L used unit-specific San Juan operating data (e.g., fuel characteristics, flue gas flow rates and temperatures, and NOx emission rates) to establish baseline operating parameters for each of the San Juan units, developed design parameters for the SNCR emission control systems and developed the SNCR cost estimates based upon those design parameters. S&L contacted Fuel Tech, a SNCR Original Equipment Manufacturer ("OEM") with experience on similar SNCR control system design projects, for preliminary equipment pricing estimates and balance-of-plant ("BOP") requirements and to develop capital and O&M costs for the SNCR control option. Fuel Tech's preliminary cost estimates for the San Juan SNCR control systems were developed based on boiler-specific operating information provided by PNM through S&L. Equipment costs were provided by Fuel Tech for the major components, including the urea handling system, injection lances, piping and pumps. Due to similarities in size, it was assumed that costs would be similar for each "sister" unit (e.g., Units 1 & 2 and Units 3 & 4).

C. Methodology Used to Develop San Juan SCR Cost Estimates

Similarly, S&L used unit-specific San Juan operating data to establish baseline operating parameters for each of the San Juan units, developed design parameters for the SCR emission control systems and developed the SCR cost estimates based upon those design parameters. In 2011, PNM contracted S&L to prepare a conceptual design, project cost estimate, and technical portions of an EPC specification as a preliminary step towards awarding a contract to install SCR control systems on San Juan Units 1, 2, 3 and 4. S&L's SCR cost estimate submitted to NMED in February 2013 was based on costs provided by equipment vendors for the major components of the SCR control system, including the SCR reaction vessel, SCR catalyst, and ammonia handling systems, and unit-specific BOP costs for items such as the economizer bypass modifications, ash handling modifications, tie-ins, ductwork, fan modifications, foundations and

structural steel. S&L completed the following initial tasks to establish the SCR control system design parameters:

- Reviewed and analyzed current operating conditions at San Juan, including air flow, temperature data, fuel data, ash flow and handling, fan capacity, and alternative reagents;
- Reviewed the ductwork and/or boiler stiffening that would be required to withstand the new operating conditions required for compliance with NFPA-85, air heater modifications and modifications necessary after the SCR addition;
- Evaluated the existing auxiliary electric system to determine what modifications would be required to accommodate the addition of SCRs and the sorbent injection system, discussed below;
- Developed General Arrangement ("GA") drawings for the SCRs, new ductwork and the other additional equipment required to safely and reliably integrate the SCRs into the plant's operations; and
- Estimated the quantities of materials (e.g., steel, concrete, piping, ductwork, etc.) needed for SCR installation based on the GA drawings.

D. Design Basis Used to Develop the San Juan SNCR and SCR Cost Estimates

San Juan is located 15 miles west of Farmington, New Mexico, and is comprised of Units 1 and 2 (nominally 370 MW each) and Units 3 and 4 (nominally 544 MW each). The generating station is situated at an elevation of approximately 5,300 feet above mean sea level (MSL). All four units fire western subbituminous coal produced at an adjacent mine. The steam generating units for Units 1 and 2 were manufactured by Foster Wheeler Corporation and the steam generating units for Units 3 and 4 were manufactured by the Babcock & Wilcox Company. Units 1, 3 and 4 are equipped with steam turbine generators manufactured by General Electric, whereas, Unit 2 utilizes a Westinghouse steam turbine generator. All four units are currently designed with low-NOx burners and overfire air systems to control NOx emissions, activated carbon injection for mercury control, pulse jet fabric filter baghouse control systems for

particulate matter control and wet flue gas desulfurization for sulfur dioxide ("SO_2") control. The units are also equipped with hot-side electrostatic precipitators ("ESPs") that were de-energized when the baghouses were installed between 2006 and 2009.

Operating parameters affecting the design of both SCR and SNCR control technologies include, but are not necessarily limited to, boiler heat input, flue gas volumes and residence time, flue gas temperatures, boiler NOx emissions and the design target NOx emission rate. Operating parameters for the San Juan units were developed based on Process Information data available from the station, as well as experience from similar coal-fired boilers. Design and operating parameters used as the basis of the SCR and SNCR cost estimates are summarized in Table 2 below.

Table 2: San Juan Units 1, 2, 3 and 4 Operating Parameters

Plant Operating Data						
Variable	**Units**	**Unit 1**	**Unit 2**	**Unit 3**	**Unit 4**	**Status***
Gross Load	MW	370	370	544	544	v
Minimum Load	MW	144	144	222	222	v
Heat Input	mmBtu/hr	3,707	3,688	5,758	5,649	v
O_2 at Economizer Outlet	%vol (set)	3.36	2.67	3.00	2.78	v
Air H_2O	lb/lb dry air	0.013	0.013	0.013	0.013	ej
Ash-Boiler	wt%	20	20	20	20	ej
Ambient Pressure	psia	12.08	12.08	12.08	12.08	v
Ambient Temp	°F	70	70	70	70	v
Economizer Outlet Pressure	in. w.c.	+11.7	+11.4	+6.9	+7.3	v
Boiler SO_2 to SO_3 oxidation	wt% SO_2	0.8	0.8	0.8	0.8	ej
Control System Design Parameters						
SCR SO_2 to SO_3 Oxidation	wt% SO_2	0.5	0.5	0.5	0.5	design
Economizer Outlet Temperature	°F	658 ± 15	670 ± 20	670 ± 20	680 ± 15	v
Minimum Load Temperature	°F	500	475	450	450	ej
Inlet Ash	lb/mmBtu	18.34	18.34	18.34	18.34	v

Loading						
Maximum Inlet NOx	lb/mmBtu	0.40	0.40	0.40	0.40	design
Average Inlet NOx	lb/mmBtu	0.30	0.30	0.30	0.30	design
NOx Emission Limit (SCR)	lb/mmBtu	0.05	0.05	0.05	0.05	design
SCR Pressure Drop	in. w.c.	-8.0 to -11.0	-8.0 to -11.0	-8.0 to -11.0	-8.0 to -11.0	design
NH_3 Slip (SCR)	ppmvd @3% O_2	2	2	2	2	design
NOx Emission Limit (SNCR)	lb/mmBtu	0.23	0.23	0.23	0.23	design
NH_3 Slip (SNCR)	ppmvd @3% O_2	10	10	10	10	design

* v = verified; uv = unverified; ej = engineering judgment; design = design criteria

E. Factors that Affect the Design, Effectiveness, and Costs of an SNCR Control System

Several site-specific factors affect the design, effectiveness and costs of an SNCR control system. Based on our experience with the design and operation of other SNCR control systems, operating parameters affecting SNCR design include the carbon monoxide (CO) concentration in the boiler flue gas, flue gas temperatures and residence times, and the NOx reduction requirements.

Industry experience has shown that CO levels below 1,000 ppm at the boiler's bull nose are needed to obtain the highest NOx removal efficiencies with SNCR. If CO levels exceed 1,000 ppm at the bull nose, SNCR may not be viable control technology due to a number of factors, including low urea utilization, low removal efficiency and high ammonia slip. S&L's SNCR equipment cost estimates were developed based on the assumption that CO concentrations in each boiler at the bull nose can be controlled to a level that allows for effective NOx removal. The controlled, or target level, NOx emission rate and NOx removal efficiency required to meet that emission rate are also important design considerations. The target removal efficiency will affect the urea consumption rate, number of urea injectors and the injector locations and design.

Regardless of the target level NOx emission rate, SNCR control efficiency will be limited by flue gas temperatures, residence times within the requisite temperature window, the ability to adequately mix urea into the flue gas, and the acceptable level of ammonia slip.

Design, quantity, type, and placement of the injectors are critical to SNCR performance, as the injectors are used for dispersion of diluted urea solution within targeted areas of the boiler. Residence time, flue gas temperatures and droplet size are important design parameters controlled by injector placement. Effective NOx removal can only be achieved with adequate NOx-urea mixing within the requisite temperature zone in the boiler. Fuel Tech's proposal included several urea injector options, including options for retractable injectors, High Energy Reagent Technology ("HERT") lances, and Multi-Nozzle Lance injectors. Locating the urea injection lances within the appropriate temperature window within the boiler, and designing the lances to promote flue gas/urea mixing, are both important design considerations for an SNCR control system.

Based on Fuel Tech's proposal, and S&L's experience with other SNCR projects, the cost estimate was developed based on the assumption that the SNCRs at San Juan could be designed to achieve NOx removal efficiencies of approximately 25%. Assuming an average NOx emission rate of 0.30 lb/mmBtu with the existing combustion controls, the SNCRs would achieve controlled NOx emissions of approximately 0.23 lb/mmBtu. SNCR cost estimates were based on injector locations selected by S&L based on industry experience and assuming the use of HERT injectors (or the equivalent); however, the exact locations of the injectors will be determined by the SNCR OEM based on computational fluid dynamics ("CFD") modeling of the furnace, and boiler gas species mapping will need to be done before the SNCR OEM can supply PNM with a removal efficiency guarantee.

As part of the SNCR design review process, PNM verified that San Juan may need to reduce fugitive emissions at the plant. Converting the units from their existing pressurized design to balanced draft operation, which means internal pressures in the boilers and ductwork will be close to atmospheric pressure, is one option to minimize fugitive emissions. Balanced draft conversion would require the installation of new fans, boiler and ductwork stiffening, and upgrades to the existing electrical systems. However, unlike the SCR project described below, it is our opinion that SNCR could be installed and operated on the units without these upgrades; therefore, balance draft costs were not included in the SNCR cost estimate.

F. Factors Affecting the Design, Effectiveness, and Costs of a SCR Control System

Several site-specific factors affect the design, effectiveness and costs of SCR control systems. Design considerations affecting the SCR cost estimates include the congested existing plant configuration, the high ash content of the coal that is fired in the units, NOx reduction requirements, and the existing and anticipated permit limits for other regulated air pollutants. Some of the more significant factors affecting the design and costs of the San Juan SCR control systems are described in more detail below.

Site Congestion: San Juan is a congested site. A significant congestion issue affecting SCR design and construction at San Juan is the fact that all four units are equipped with de-energized hot-side ESPs, which are located ahead of the boilers' air preheaters ("APH") in the flue gas path. Most coal-fired power plants have cold-side ESPs that are located downstream of the APH. Because the ESPs at San Juan are located in front of the APHs, they are in the middle of the boiler outlet duct area, the same area where the SCRs would be located. In addition, the existing stacks are located adjacent to the air pre-heaters, severely restricting the area in which SCRs would be installed.

The conceptual design study prepared for the SCR control systems concluded that, given the space constraints, the best location for the SCRs will be above the existing air pre-heaters. Building SCRs in this location would require installation of ductwork to convey the full gas path above the hot-side ESPs. Thus, the bottom ducts of the SCRs would be approximately 120 feet above ground level, requiring significantly more structural support than would be required if the SCRs could be located closer to the ground.

Another manifestation of the congested site is that all four units are constructed side by side in a row. This leaves two units (Unit 2 and Unit 3) on the interior of the rows, where there is very little space between the units. This tight configuration creates constructability issues because it limits crane selection and placement as well as the type of structural foundations that can be added to support the weight of the SCR. Crane placement is important because of the need to build the ductwork over the existing ESPs, which means lifts spanning above the outside units will be required to reach the two interior units. The long spans and limited placement choices restrict the crane selection choices to larger more expensive cranes.

The congestion also limits the options for structural steel column placements to support the new SCR reactors and ductwork, contributing to a less efficient steel arrangement and increasing the complexity of the design compared to a more open installation. The tight site configuration also dictates that a more expensive type of deep structural foundation must be used to support the SCR structure. Low overhead clearances and tight quarters adjacent to the existing stacks, particularly south of the Unit 1 stack (where the adjacent restricts access to the area) and also south of the Unit 2 stack (where existing ash piping would hamper access during construction), leads to the choice of micropiles for support of the new SCRs and ductwork. This construction option is a special type of pile that requires special installation equipment and expertise. The installed cost of this type of pile by a specialty contractor will be high compared to other deep

foundation installations, at least double the cost of conventional drilled or driven piles. The cost of structural foundations also increases due to the height of the SCR above ground level

Controlled NOx Emission Limit: Based on the August 22, 2011 EPA FIP, the San Juan SCRs would be required to achieve an enforceable NOx emission limit of 0.05 lb/mmBtu (30-day rolling average). To meet this limit, the SCRs must be designed to achieve controlled NOx emissions of less than 0.05 lb/mmBtu at full load operating conditions to provide compliance margin during those periods of time when NOx emissions may exceed the limit (e.g., startup, shutdown, low-load cycling and malfunction). To meet a permit limit of 0.05 lb/mmBtu, S&L's SCR design criteria included a design target NOx emission rate of 0.03 lb/mmBtu, which, based on our experience, is equivalent to the most aggressive design target emission rate currently available for control system vendors. The design target emission rate represents actual controlled NOx emissions achievable at full load steady state operating conditions, under new and clean conditions. Operating history at existing coal-fired facilities, including emissions data[15] referenced by the National Park Service ("NPS") in their comments dated July 24, 2013[16], indicate that an operating margin of approximately 0.02 lb/mmBtu between the control system design target and the enforceable 30-day average permit limit is required to provide a reasonable chance of continuous compliance on a long-term basis.

To achieve controlled NOx emissions of less than 0.05 lb/mmBtu, the conceptual design study determined that the San Juan SCRs must be designed to hold four layers of catalyst. Three layers would be installed initially, with the fourth layer being added after approximately two years of operation. Once the fourth layer has been added to the SCR, one layer of catalyst would be replaced every two years. The four-layer catalyst design requirement affects SCR costs by:

[15] Letter dated July 24, 2013 from the National Park Service to Ms. Rita Bates, Planning Section Chief, Air Quality Bureau, NMED ("NPS Comments").
[16] 2000-2012 Annual NOx Data from EPA's Air Markets Program Data. http://ampd.epa.gov/ampd/

- Four layers of catalyst results in a larger SCR reaction box and additional weight that must be supported by the structural steel;
- Fan upgrades will be required to accommodate the additional pressure drop across the SCRs;
- Increased ammonia consumption will be required to achieve the lower NOx emission rate, which affects the cost of the ammonia handling system, ammonia storage and delivery to the SCRs;
- The additional layer of catalyst will result in increased SO_2 to SO_3 oxidation across the SCR and the formation of sulfuric acid mist ("SAM") emissions, requiring dry sorbent injection control to address increased sulfuric acid mist emissions; and
- Increased construction costs in terms of initial catalyst procurement.

SAM Limit: San Juan is required by the Regional Haze FIP to meet a SAM emission limit of 2.6 x 10^{-4} lb/mmBtu (or approximately 0.10 ppmvd @ 3% O_2). SCR controls result in increased SO_2 to SO_3 oxidation. SO_3 formed across the SCR catalyst can react with water in the flue gas to form SAM, increasing SAM loading to downstream equipment. In order to minimize the formation SAM emissions, the conceptual design study specified an ultra-low conversion catalyst to minimize SO_3 formation across the SCR. Ultra-low conversion catalyst will increase the volume of catalyst required to achieve NOx removal and increase the size, weight and cost of the SCR reactor vessels. Based on vendor input from recent SCR installations, it is unlikely that PNM will be able to obtain a guaranteed SAM emission limit of 2.6 x 10^{-4} lb/mmBtu from any of the SCR contractors. Therefore, the conceptual design study specified installation of a dry sorbent injection ("DSI") control system for SO_3 control on both units. DSI control systems will be needed to address increased SAM emissions associated with the installation and operation of the SCR control systems.

Fugitive Emissions Control and Balanced Draft Conversion: As part of the SCR design review process, PNM verified that San Juan may need to convert to a balanced draft configuration to

reduce existing fugitive emissions caused by the boilers' pressurized design. Converting the plant to a balanced draft operation, which means internal pressures in the boiler and ductwork will be close to atmospheric pressure, would minimize the fugitive emissions. The existing fans on all four San Juan units have limited capacity, and, because of the significant pressure drop across the SCR, new induced draft ("ID") fans will be required on all four units. New fans will be required for SCR operation, regardless of whether the units are converted to balanced draft. However, because of the potential need to address fugitive emissions, ancillary equipment costs (including fan sizing, boiler and ductwork stiffening requirements, auxiliary power requirements, and electrical system upgrades) were developed to address both the pressure drop through the SCR and balanced draft conversion. Balanced draft conversion would incrementally add to the size (and cost) of the new fans and electrical system upgrades, and would require additional boiler and ductwork stiffening. Based on an evaluation of fan sizing needed for the SCR project and the additional fan capacity needed for balanced draft conversion, these costs were split between the two projects by assigning 80% of the costs to the SCR and 20% to the additional costs needed for balance draft conversion. Balanced draft conversion costs were not included in the San Juan SNCR cost estimates.

G. Project-Specific SNCR Design Criteria and Assumptions Used to Develop the San Juan Cost Estimates

Based on a review of the NOx reduction requirements and retrofit challenges for the installation of SNCR control systems and associated plant changes at San Juan, the following project-specific issues were taken into consideration in the development of the San Juan SNCR cost estimates:

Urea Delivery, Unloading, and Storage. The SNCR cost estimate was based on using urea as the reactant. Urea solution (50% aqueous urea by weight) would be delivered to the site via truck to the urea unloading area. Urea is a solid on its own, but when mixed with water it becomes a

clear liquid solution. Urea would be delivered as a liquid and unloaded via onboard truck pumps into fiberglass reinforced plastic ("FRP") storage tanks. Total storage capacity was sized for 14 days of continuous operation per unit at full load. The storage tanks would be heat traced and insulated in order to keep the 50% urea solution above 80°F to prevent precipitation of urea solids out of solution.

Urea Circulation. The urea storage tanks would be cross tied and designed to transfer the 50% urea solution from the storage area to the units via 2 x 100% centrifugal pumps. The urea solution would be transferred using stainless steel piping. A loop from the storage tanks to the unit metering modules and back to the storage tanks would continuously circulate the 50% urea solution. Process heat trace would be required to keep the urea solution above 80°F.

Urea Dilution and Metering. Dilution water would be pumped via 2 x 100% centrifugal pumps to the metering modules located in the units, where it would mix with the 50% urea solution prior to injection into the boilers. Dilution of the urea solution to 5-10% (by weight) urea is required prior to injection. Variable frequency drives would be utilized to maintain a constant pressure of dilution water in response to changing flow demands. The metering modules provide flow and pressure control of the fluids used in the SNCR process.

Diluted Urea Distribution and Injection. Distribution modules would provide diluted urea solution and atomizing air to individual injectors. The modules are typically located near the injectors on the same elevation. The injectors are used for dispersion of diluted urea solution within targeted areas of the boiler. Furnace temperature, residence time and droplet size are important design parameters controlled by injector placement. The exact locations of the injectors will be determined by Fuel Tech based on CFD modeling of the furnace. For the SNCR cost estimate, injector locations were selected based on S&L's industry experience, assuming the use of HERT injectors or the equivalent.

BOP Systems. Demands on the ancillary systems are influenced by the Fuel Tech's equipment design. BOP systems and costs were based on the Fuel Tech budgetary cost proposal provided for San Juan.

Raw Water & Water Treatment. Raw water will be needed as urea dilution water. S&L determined that a tie-in to the existing raw water line located below grade between Units 3 and 4 could be accessed to supply the required water. Based on a review of the station's existing water supply system, adequate pressure, flow and pump redundancy are currently available at this tie-in location. S&L also received a water analysis for the raw water and reviewed the SNCR OEM dilution water quality requirements. In order to meet the dilution water quality requirement by the SNCR OEM, a water treatment system will be required. The water treatment system would include filters to remove suspended solids, zeolite softeners for the removal of hardness and a 10,000 gallon head tank for temporary dilution water storage. Costs for a common water treatment system were included in the San Juan SNCR cost estimate.

Plant and Instrument Air System. The addition of the SNCR system adds a large air user to each unit. To meet the air consumption requirements for the atomizing air, 2 x 100% capacity oil-free compressors would be needed for each unit. These compressors would also provide compressed air to all new intermittent-users (e.g., valves, instruments, tools, etc.); therefore, no additional compressed air load would be added to the existing plant compressed air systems. All air would be dried to -40 °F dew point using 2 x 100% regenerative desiccant dryers. Instrument air piping would be stainless steel.

Air Heater Evaluation. In some cases, the application of SNCR technology to coal-fired power plants can create potential problems with the deposition of ammonia-sulfur salts in the boiler's APH. Urea injected in the boiler decomposes into ammonia and is not fully consumed in the ammonia-NOx reactions, resulting in excess ammonia that exits through the economizer

(referred to as ammonia slip). Sulfur trioxide ("SO_3") formed in the boiler from oxidation of sulfur in the coal can react with the excess ammonia to form ammonium bisulfate ("ABS"). ABS can condense from the gas stream and form a sticky deposit on the heat transfer surface of the APH at temperatures of 380-450°F. Fly ash particles tend to stick to the ABS resulting in the gradual pluggage of the APH. At San Juan, based on preliminary estimate of SO_3 generated in the boiler, it is not expected that coating of the APH baskets will be necessary, and costs for these upgrades were not included in the SNCR cost estimates. However, before knowing exactly how much gaseous SO_3 and ammonia will pass through the APH, the performance should be closely monitored.

Fire Protection System. Fire protection for the new pre-engineered buildings would include alarm and detection, as well as fire extinguishers. It is anticipated no additional fire hydrants or a dispersion system will be required for the urea unloading area.

Furnace Modifications. Penetrations in the boiler water wall will be required at the urea injector locations. To support the injector penetrations, water wall tubes would need to be removed and replaced with tubes curved around the penetration locations. Injectors would be mounted onto a flange; however, in some instances additional structural reinforcement would likely be required to support the injectors.

Lighting and Maintenance Power System. The SNCR cost estimate was based on the assumption that the lighting power system would consist of normal AC lighting, DC emergency lighting and convenience receptacles, and that the lighting system would follow the lighting system at the existing plant.

Grounding System. The SNCR estimate was based on the assumption that the station's grounding system would be extended with an interconnected network of bare copper conductors

and copper ground rods. The systems would be designed to protect plant personnel and equipment from the hazards that can occur during power system faults and lightning strikes. The grounding system would be designed in accordance with applicable Institute of Electrical and Electronic Engineers ("IEEE") standards and installed in accordance with the National Electrical Code ("NEC"). Lightning protection design would be in accordance with NFPA 780.

Process and Freeze Protection Heat Tracing System. Freeze protection systems would be provided for outdoor piping (8" and smaller), instruments, and other devices subject to freezing in cold weather. The freeze protection system would be designed to accommodate both normal plant operations and extended plant shutdowns during cold weather. All urea piping and tanks would be process heat traced to a minimum temperature of 80°F to avoid crystallization.

H. SCR Design Criteria and Assumptions Used in Cost Estimates

Based on a site-specific review of the NOx reduction requirements and retrofit challenges associated with the installation of SCR control systems at San Juan, the following project-specific issues were taken into consideration in the development of the SCR cost estimates:

SCR Location. The proposed SCR reactors would be located above the existing air heaters. Ductwork from the economizer outlet to the air heater inlet would be removed. Galleries would be provided at each catalyst level, at the ammonia injection grid level and at the ash handling levels to allow for maintenance and inspection of the SCR system.

SCR Reactors. The conceptual design calls for a single reactor per unit for Units 1 and 2 and two reactors per unit for Units 3 and 4. Each reactor would have slots for four layers of catalyst and be designed to use anhydrous ammonia as the reagent.

Economizer Bypass. Based on San Juan coal parameters, an economizer outlet temperature of at least 580°F will be required for proper operation of the SCR. If flue gas flowing through the SCR is less than 580°F, ammonia cannot be injected into the SCR and catalyst activity will be

reduced. For periods of operation when the economizer outlet temperature is less than 580°F, a means to increase the outlet temperature must be included in the SCR design. Water-side economizer bypass systems have been used on other recent SCR installation projects to increase economizer outlet temperatures, and a similar low-load temperature control system would be needed on the San Juan units to allow unit cycling and low-load operation. Thus, economizer bypass costs were included in the cost estimate for the San Juan SCRs.

Demolition of the Existing Hot-Side ESPs. Demolition of the existing hot-side precipitators will be needed to fit the retrofit SCR control systems into the available space. Given the boiler configurations, the SCR control systems would have to be placed above the existing air heaters. Thus, the bottom of each SCR will be approximately 120 feet above ground level. Due to the height of the ductwork leading to the air heaters, the top of the SCRs will approach the top of the boiler buildings. If this height is exceeded, potential impacts on the existing chimneys and plume dispersion would need to be evaluated. As designed, the bottom of the inlet duct to the SCR runs at the same elevation as the top of the hot-side ESPs, necessitating removal of the ESPs. Reusing the existing ductwork was evaluated and found not to be acceptable due to the increase in flue gas velocity. We also evaluated using the top hot-side ESPs as a duct, but again the degradation of the equipment and flue gas velocities would not support the design.

Catalyst Layers. To achieve the required NOx emission reductions on a consistent basis with ultra-low SO_2 to SO_3 conversion catalyst, three layers of catalyst, rather than the two layers specified for other similar projects, will be required for the San Juan SCRs. The San Juan SCRs would be designed to hold four layers of catalyst, with three layers being loaded initially. The additional layer of catalyst is needed to meet an enforceable NOx emission limit of 0.05 lb/mmBtu, which could not be met with two layers. The fourth layer of catalyst would be added to the SCR after approximately two years of operation. Furthermore, the ash content of the coal

used at San Juan results in increased costs for the catalyst, as well as increased complexity and costs of the ash handling systems.

Air Heater Modifications. Based on the temperatures expected for the SCR operation, it can be expected that ammonia and SO_3 will react to form ammonium bisulfate in the intermediate section of the existing air heaters. However, based on operating experience with low sulfur fuels that contain calcium oxide in the fly ash, air heater plugging and corrosion is not expected on these units. Therefore, no costs were included for air heater modifications.

Economizer Ash Handling System. The existing economizer ash handling system on the San Juan units has been taken out of service, and the top of the ash hoppers is covered with a metal plate. To remove large particles of ash prior to the SCR, this abandoned system needs to be removed and a new system installed. The new system would consist of a dry ash chain conveyor that collects the economizer ash in a storage tank and uses the bottom ash system to sluice the ash to the existing dewatering bins. Installing this system would also require demolition of the existing gas recirculation fans to make room for the ash collection tanks.

Baghouse Ash Handling System. Baghouse control systems have been installed on all four units at San Juan. The ash handling system installed with the baghouses was designed to collect only a portion of the fly ash because up to 50% of the fly ash particulates fall out in the existing de-energized hot-side ESPs. Removing the existing ESPs, which will be needed to install the SCR control systems, will increase particulate loading to the baghouses and increase the quantity of ash handled by the baghouse ash handling system. This change would require expanding the baghouse ash handling system to accommodate the additional ash flow. Costs to upgrade and expand the baghouse fly ash handling system were included in the San Juan SCR cost estimate.

Sootblowers on SCR. The method of cleaning the fly ash that settles on the catalyst is extremely important to obtain the guaranteed life of the catalyst. For this reason, the use of steam

sootblowers, in addition to sonic horns, is recommended for the San Juan units. Steam sootblowers will remove fly ash that settles on the catalyst and the sonic horns will keep the fly ash moving through the catalyst. S&L's cost estimate was based on the assumption that the top layer of catalyst would be provided with steam sootblowers, and that the balance of the catalyst layers would be cleaned using sonic horns. This system will require compressed air to operate. A separate compressor for each unit was assumed for the cost estimate.

Large Particle Ash Screen. To collect the maximum amount of fly ash at the economizer hopper, a large particle ash screen will be installed at the exit of the economizer. This ash screen will be used to divert larger fly ash particles that can plug the SCR catalyst into the economizer ash hoppers. This may also eliminate the need for additional fly ash systems at the SCR inlet and outlet ductwork.

SCR Catalyst Replacement. An elevator was included in the SCR cost estimate to replace spent catalyst at the end of the catalyst life.

DSI. The SCR will increase the formation of SO_3 and SAM loading to downstream equipment. DSI control systems are required if the units are going to meet the FIP SAM emission limit. Therefore, costs for a DSI control system were included in the SCR cost estimate.

Ammonia System. The location of the ammonia system is dependent on the type of ammonia being used and whether each unit will have a separate ammonia storage facility. The SCR cost estimate was based on the assumption that all four units would share a single ammonia storage facility with the associated truck delivery and unloading facilities. Costs for the ammonia storage system were divided between each unit based project ammonia consumption rates.

Auxiliary Power Upgrades. Operation of the SCR control system will require upgraded fans and electrical systems to allow the plant to operate at full load with the additional pressure loss generated by the SCRs. Fan modifications include replacement of the rotors and other fan

modifications for the forced draft ("FD") fans on all units, replacement of the ID fans and motors on all units and addition of variable frequency drives to replace the existing fan inlet dampers. The existing electrical system of Units 1 and 2 are not capable of handling the new fan loads required to operate the SCR control systems, and will likely require a new power line and related electrical equipment from the existing switchyard. Costs for these upgrades were included in the Unit 1 cost estimate.

Structural Stiffening. Structural stiffening of the boiler, ductwork and equipment downstream of the boiler will be required to operate the SCR control systems and to operate the plant in a balanced draft configuration.[17] These costs were included, along with the fan and electrical system upgrades, in the balanced draft conversion cost estimate. However, as discussed above, a majority of these costs would be incurred with the installation of SCR control systems and not with the concurrent balanced draft conversion. Based on pressure drop considerations and fan limitations, these costs were split between the SCR and balanced draft projects by assigning 80% of the costs to the SCR and 20% to the additional needed for balance draft conversion.

Control Systems. The existing Distributed Control System ("DCS") system will need to be expanded to accommodate additional signals from the SCR system.

Construction Costs and Special Cranes. A review of the site arrangement shows that the free space between the units is limited due to modifications to the plant with the addition of the baghouses and the coal conveyor running between the units. In order to have the lifting capacity that would be required to install the SCRs, and accommodate the demolition that is required, special cranes would be required, increasing the complexity of the project. Construction

[17] The conversion to a balanced draft configuration at San Juan is not part of the Revised SIP. PNM is undertaking this project to assist the plant in meeting the CAA National Ambient Air Quality Standards (40 CFR Part 50).

difficulty is very high for this very congested site, and was taken into consideration in the evaluation of construction and labor costs.

I. Economic Assumptions Used to Develop SNCR and SCR Capital Cost Estimates

As allowed by the Control Cost Manual, TCI includes all costs required to purchase equipment needed for the control system, costs of labor and materials for installing the equipment, and certain indirect installation costs. Indirect costs included in the calculation of TCI include costs such as engineering costs, construction and field expenses, contractor fees, start-up and performance test costs, and contingencies. Indirect capital costs are typically calculated as a percentage of the total direct capital costs.[18]

Capital cost estimates prepared by S&L for the San Juan control systems were based largely on budgetary equipment costs provided by equipment suppliers, costs incurred on similar projects and S&L's experience with the design and installation of retrofit SNCR and SCR control systems. Allowances were included, where necessary, to address site-specific retrofit issues described above. Assumptions used to calculate the direct and indirect capital costs are summarized below:

Contracting Strategy. Capital costs for the SCRs and associated plant modifications were based on hiring an EPC contractor to provide a "turn-key" air quality control system. Design of the control system would be performed by the EPC contractor. All equipment would be purchased and installed by the EPC contractor.

Equipment Costs. Equipment costs include only those costs for the manufactured equipment. For the SNCR control system these items include the SNCR system, compressors, water treatment, tanks, pumps and motors. For the SCR control system these items include the SCR reactor vessel and catalyst modules, economizer bypass and low load temperature control system, ammonia

[18] Control Cost Manual, Section 4.2, Chapter 2, page 2-43.

system, dry sorbent injection control system, baghouse fly ash handling system upgrades and related ancillary equipment.

Material Costs. Material costs include those costs for commodity-like materials, such as structural steel, concrete, piping, valves, cable, cable tray and conduit. All material unit costs were estimated on the basis of S&L in-house data, vendor catalogs and industry publications. Quantities of materials were developed based on the conceptual designs and general arrangement drawings prepared for each control system.

Labor Costs. Union craft labor rates were developed for both projects for the Albuquerque, New Mexico area from the publication *RS Means*. Union rates were then incorporated into work crews appropriate for the activities by adding allowances for payroll taxes, worker's compensation, fringe benefits, incidentals, small tools, construction equipment and site overheads to arrive at crew rates detailed in the cost estimate.

SNCR Labor Incentives. Labor incentives for the SNCR work are estimated based on 5 days x 10 hours/day work week for the non-outage work. The boiler tube insert modifications and scaffolding required for this work will be performed during an outage, and are estimated based on 6 days x 10 hours/day work schedule. The cost estimate reflects this assumption for overtime calculations. For common areas, it was assumed that all work would be performed during pre-outage, and therefore reflects 5 days x 10 hours/day schedule.

SCR Labor Incentives. Labor incentives for the SCR work were estimated based on 5 days x 10 hours/day work week for the non-outage work. Outage labor incentives were estimated based on 7 days and two shifts of 12 hours/day.

Labor Productivity. A 1.15 labor productivity factor was used in the cost estimates based on the regional labor productivity factor in the New Mexico area as published in Compass International Global Construction Cost and Reference Yearbook.

Project Indirect Costs. Project indirect costs for the SCR and SNCR cost estimates include:

- Freight - Materials: 5% of Material Cost
- Freight – Equipment: Included in equipment cost
- Consumables: 0.5% of Labor & Materials
- Sales Tax: Not included
- SCR EPC Services: 8% of total direct & construction indirect costs
- SNCR EPC Services: 6% of total direct & construction indirect costs
- SCR EPC Management Support: 3% of total direct & construction indirect costs
- SNCR Owners Engineering: 2% of total direct & construction indirect costs
- SNCR Construction Mgmt Support: 2% of total direct & construction indirect costs
- SCR Owners Eng. & Const. Mgmt 4% of total direct & construction indirect costs
- EPC Startup & Commissioning 1% of total direct & construction indirect costs
- EPC Fee: 15% of total direct & construction indirect costs

Escalation. Escalation is typically included in cost estimates for major retrofit control projects and is intended to account for increases in equipment, material, and labor costs that occur during the duration of the project. However, escalation is not included in the constant dollar cost estimating methodology described in the Control Cost Manual; thus, S&L did not include escalation in its SCR/SNCR cost estimates. Cost estimates prepared by S&L are shown in 2013 dollars.

Contingency. Contingency is intended to represent unforeseeable elements of cost, particularly in fixed investment estimates, which previous experience has shown to be statistically likely to occur. Contingency is allowed by the Control Cost Manual approach, and should be based on the level of project definition (typically expressed as the percent of complete design). Contingency was included in both the SNCR and SCR cost estimates as follows:

1. Contingency (SNCR):
    - 10% of Equipment Costs[19]
    - 20% of Material Costs
    - 20% of Labor Costs
    - 20% of Construction Indirect Costs
2. Contingency (SCR):
    - 20% of Total Direct and Indirect Construction Costs

Allowance for Funds Used During Construction ("AFUDC") or Interest During Construction ("IDC"). AFUDC and/or IDC were not included in the SCR/SNCR cost estimates. AFUDC accounts for the time value of money associated with the distribution of construction cash flows over the construction period, which for an SCR system could be spread over a construction period of 36+ months. TCI, as defined in the Control Cost Manual, includes all costs required to purchase equipment needed for the control system (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and building, working capital and off-site facilities.[20] Thus, the time value of money, measured by the real discount rate, should be included in the calculation of total capital costs and is consistent with the constant dollar approach described in the Control Cost Manual. AFUDC represents a significant cost that PNM will incur with an SCR project (estimated to be in the range of $38 to $45 million). Nevertheless, to be consistent with cost estimates prepared by EPA, S&L did not include AFUDC its capital cost estimate for the San Juan SCR and SNCR control systems.

New Mexico Gross Receipt Tax ("NMGRT"). The NMGRT of 6.3125% was applied to the total cost (i.e., purchased equipment and services performed) of both the SNCR and SCR projects.

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[19] A lower contingency of ten percent was assigned to SNCR Equipment costs primarily due to the fact that major component costs were based on a budgetary quote provided by Fuel Tech an OEM of SNCR equipment.

[20] Control Cost Manual, Section 1, Chapter 2, page 2-5.

J. Methodology for Estimating Capital Costs of SNCR and SCR

S&L followed the approach described in EPA's Control Cost Manual to develop total capital costs, total annual O&M costs and total annual costs for the San Juan control systems. As described above, the Control Cost Manual provides a methodology for calculating the total annual costs associated with an air pollution control system by annualizing the costs of installation, maintenance and operation in constant net present value dollars over the life of the control system. The Control Cost Manual describes the equipment and other direct costs that are typically included in a cost estimate, and provides cost factors that can be used to calculate certain indirect costs, if needed.

With respect to providing SCR cost estimates, the Control Cost Manual states that "the Manual deviates from its standard approach of providing study level costs and, instead, provides a detailed description of the factors that influence the TCI [Total Capital Investment] for the analyst to consider when dealing with a vendor quotation."[21] Chapter 2 of Section 4.2 of the Control Cost Manual (referred to as the "SCR Chapter") provides design specifications and a costing methodology for SCR applications for large industrial boilers, as well as an example cost estimate for a 1,000 mmBtu/hr, or approximately 100 MW, wall-fired industrial boiler firing subbituminous coal.

The SCR Chapter was written in October 2000, and costs presented in the chapter are based on 1998 dollars.[22] The direct capital cost equation in the Control Cost Manual takes into consideration flue gas flow rates and temperatures, inlet and outlet NOx concentrations, and the fuel sulfur content; and includes adjustment factors the SCR reactor height, ammonia flow rate, SCR bypass, initial catalyst charge and a retrofit adjustment for existing boilers.[23] However, the

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[21] *Id.* at page 2-27.
[22] Control Cost Manual, Section 4.2, Chapter 2, page 2-40.
[23] *Id.,* at page 2-42 to 2-43.

direct capital cost equation in the SCR Chapter is out of date, and does not reflect more recent experience with SCR installations. The direct capital cost equation also fails to take into consideration several key project-specific costs, such as fan and electrical system upgrades, instrumentation and control system upgrades, air preheater modifications (if required), structural stiffening requirements and DSI control to address sulfuric acid mist emission increases.

Strict adherence to the Cost Manual's direct capital cost equation does not provide an accurate case-by-case cost estimate of the actual cost of an SCR. At NMED's request, B&V prepared an SCR cost estimate using the Control Cost Manual for San Juan Unit 3.[24] B&V applied the Manual's direct capital cost equation, without modification, to San Juan Unit 3. Using the Control Cost Manual equation, and escalating the costs from 1998 to 2007 dollars, the total capital investment to install SCR on San Juan Unit 3 was estimated to be $52,298,000 or $96/kW (2007 dollars). Industry publications referenced by EPA and others clearly show that actual SCR costs are significantly greater than the capital cost estimate provided by the Control Cost Manual equation.[25]

The Control Cost Manual states that "the user has to be able to exercise 'engineering judgment' on those occasions when the procedures [described in the manual] may need to be modified or disregarded."[26] Because the direct capital cost equation in the SCR Chapter is demonstrably inaccurate, S&L did not use the equation to estimate capital costs. Nevertheless, S&L followed the methodology described in the Control Cost Manual to estimate purchased equipment costs and the costs of labor and materials for installing the equipment. Although we did not use the cost equation provided in the SCR Chapter, our approach is consistent with the methodology

[24] See, Black & Veatch, *Discussion of OAQPS Cost Manual Method for AQCS Estimation*, not dated (available in the New Mexico Regional Haze docket).
[25] See, e.g., Cichanowicz, J.E., "Current Capital Cost and Cost-Effectiveness of Power Plant Emission Control Technologies," Prepared for Utility Air Regulatory Group, January, 2010.
[26] Control Cost Manual, Section 1, Chapter 1, page 1-7.

described in the manual, and provides a more accurate estimate of the direct capital costs associated with the installation of SCR control systems on the San Juan units taking into consideration site-specific design and other constraints that affect the cost of the control system.

S&L also used project-specific cost factors to calculate the indirect capital and contingency costs for the San Juan SCR project. The example cost estimate provided in the SCR Chapter calculates indirect capital costs and contingencies using the following cost factors:

Indirect Installation Costs:

- General Facilities: 5% of Total Direct Capital Costs (TDCC)
- Engineering and Home Office Fees: 10% of TDCC
- Process Contingency: 5% of TDCC
- Project Contingency: 15% of TDCC + Total Indirect Installation Costs
- Preproduction Costs: 2% of Total Plant Costs + AFUDC

Using the Control Cost Manual example factors, the indirect installation costs, project contingency and preproduction costs total approximately 41% of the total direct capital costs. S&L followed the Control Cost Manual methodology to calculate indirect capital costs and contingencies, but used project-specific factors based on using the EPC contracting approach for the San Juan SCR project. The EPC approach, wherein a single entity is hired to engineer, procure, and construct the entire project, has become more common for the design and installation of large air pollution control systems since the Control Cost Manual was last updated. The EPC approach shifts the risk of project delays and cost overruns away from the owner and to the EPC contractor; thus, the owner will incur a premium for using this contract approach. Project cost factors used by S&L to estimate indirect capital costs and contingencies based on the EPC contracting approach included:

Project Indirect Costs:

- EPC Project Services: 8% of total direct costs and construction indirect costs
- EPC Management Support: 3% of total direct costs and construction indirect costs
- Owner's Engineering & Construction Management: 4% of total direct costs and construction indirect costs
- EPC Startup & Commissioning: 1% of total direct costs and construction indirect costs
- EPC Fee: 15% of total direct costs and construction indirect costs
- Contingency: 20% of total direct costs and indirect construction costs

Indirect cost factors used by S&L total approximately 51% of total capital costs, or approximately 10 percentage points higher than the example indirect cost factors used in the Control Cost Manual SCR Chapter. This difference is a result of the EPC contracting approach that PNM would use to install SCR control systems on the San Juan units. The Control Cost Manual states that "the application of an appropriate [indirect capital cost] factor requires the subjective application of the analyst's best judgment."[27] In this case, PNM directed that it would use the EPC contracting approach to engineer, procure and install SCR control systems on the San Juan units; therefore, indirect capital cost factors used by S&L were appropriate for the San Juan project. Nevertheless, using the default factors provided in the SCR Chapter example would reduce total capital investment by approximately 10% (the EPC premium). This change would not significantly affect the cost effectiveness of SCR control on the San Juan units.

K. Capital Costs for SNCR and SCR Based upon Site-Specific Design Criteria

Conceptual cost estimates were developed for the SNCR and SCR control systems based on the design criteria and assumptions described above. As allowed by the Control Cost Manual, capital cost estimates prepared for the control systems include all costs associated with equipment, labor, freight and the NMGRT related to the respective projects. Costs for the major system

[27] Control Cost Manual, Section 1, Chapter, page 2-27.

components were based on budgetary equipment quotes obtained from equipment vendors, S&L in-house data, vendor catalogs, industry publications and costs from other similar projects. Cost estimates for the San Juan projects include the costs to install the control systems, as well as the associated ductwork and equipment modifications taking into account site-specific operating conditions and site constraints. As noted above, S&L's cost estimates included EPC engineering, procurement and project services, as well as costs for owner's engineering and management, but did not include escalation for equipment, material or labor that could occur over the time period necessary to complete construction, and did not include an allowance for funds used during construction.

The following costs were included in the SNCR conceptual cost estimates:

- SNCR equipment
- Boiler modifications and injection lance installation
- Urea unloading area consisting of two (2) FRP tanks
- Urea circulating skids, circulating pumps
- Compressed air and dryer system
- Metering modules
- Dilution water treatment system

The following costs were included in the SCR conceptual cost estimates:

- SCR equipment & ductwork – each unit
- Demolition of upper hot-side ESP penthouse – each unit
- Demolition of hot-side ESP electrical control room
- Demolition of ash handling system on economizer hoppers – each unit
- Demolition of seal air fan area on hot-side ESPs
- Demolition of Gas Recirculation fan (1 fan Unit 3 north side and 1 fan Unit 4 south side)
- Dry flight chain conveyor system on economizer hopper with storage tank – each unit
- Sorbent injection unit for sulfuric acid control – each unit
- Sorbent silos & blowers

- Addition of a second ash handling system on the existing Units 1 & 2 baghouses, including new feeders, piping system and blowers to transport ash to existing silos
- Addition of a second ash handling system on the existing Units 3 & 4 baghouses, including new feeders, piping system and blowers to transport ash to existing silos
- Equipment and materials for gas path upgrades needed to handle pressure drop associated with SCR, as well as added scope for balanced draft conversion, as previously described in Section F
- Ammonia delivery (truck unloading station) & storage area
- Ammonia storage and tank equipment
- Common elevator for Units 1 & 2
- Elevator – each unit (Units 3 & 4)
- Additional gallery on north side of units for dilution air skids
- Demolition of sulfuric acid storage tank & spare tank in acid storage area
- Modifications to existing mechanical systems (piping modifications)

Based on the design parameters, site-specific design issues, and assumptions described above, total capital costs for the San Juan SNCR and SCR control systems are summarized in Tables 3, 4, and 5.

Table 3: San Juan – SNCR Capital Cost Summary

Cost Item	UNIT 1	UNIT 2	UNIT 3	UNIT 4
CAPITAL COST				
Total purchased equipment cost (PEC)	$3,619,200	$3,619,200	$3,597,000	$3,597,000
Total direct installation costs (DIC)	$7,369,950	$7,369,950	$7,249,050	$7,249,050
Total indirect costs (IC)	$3,038,550	$3,038,550	$2,999,150	$2,999,150
New Mexico Gross Receipts Tax (GRT)	$885,000	$885,000	$874,000	$874,000
Project Contingency (PC)	$2,478,900	$2,478,900	$2,444,300	$2,444,300
Total Capital Investment				
(TCI)=(DC)+(IC)+(GRT)+(PC)	**$17,391,600**	**$17,391,600**	**$17,163,500**	**$17,163,500**

Table 4: San Juan – Unit 1 & 2 SCR Capital Cost Summary

Cost Item	Unit 1	Unit 2
CAPITAL COST		
Total Purchased Equipment Cost (PEC)	$34,062,800	$34,077,300
Total Direct Installation Costs (DIC)	$73,397,800	$87,462,200

Total Direct Costs (DC) = (PEC) + (DIC)	$107,460,600	$121,539,500
Total Indirect Costs (IC)	$35,520,600	$39,367,300
New Mexico Gross Receipt Tax (GRT)	$9,025,700	$10,157,200
Project Contingency (PC)	$28,854,900	$32,295,900
Total Capital Investment (DC + IC + GRT + PC)	**$180,861,800**	**$203,359,900**

Table 5: San Juan – Unit 3 & 4 SCR Capital Cost Summary

Cost Item	Unit 3	Unit 4
CAPITAL COST		
Total Purchased Equipment Cost (PEC)	$42,064,000	$42,064,800
Total Direct Installation Costs (DIC)	$114,139,000	$96,763,200
Total Direct Costs (DC) = (PEC) + (DIC)	$156,203,000	$138,828,000
Total Indirect Costs (IC)	$52,438,700	$47,434,600
New Mexico Gross Receipt Tax (GRT)	$13,170,500	$11,757,800
Project Contingency (PC)	$42,395,600	$37,919,600
Total Capital Investment (DC + IC + GRT + PC)	**$264,207,800**	**$235,940,000**

L. Calculations for Total Annual Costs for SNCR and SCR

S&L followed the Control Cost Manual methodology to calculate total annual costs for the San Juan SNCR and SCR control systems. Total annual costs were calculated as the sum of the fixed and variable O&M costs plus the annualized cost of capital.[28] The annualized cost of capital was calculated by multiplying the total capital investment by a capital recovery factor ("CRF") calculated using the following equation from the Control Cost Manual:[29]

$$CRF = \left(\frac{i(1+i)^n}{(1+i)^n - 1} \right)$$

Where "n" equals the useful equipment life and "i" is an interest rate. Example calculations provided in the Control Cost Manual use a social discount interest rate of 7.0% and an equipment life of 5 to 25 years to calculate the CRF (depending on the control system).[30] However, Section

[28] *Id.* at page 2-7.
[29] *Id.* at page 2-21.
[30] *Id.* at page 2-13.

2.4.2 of the Control Cost Manual (Interest Rates) states that "the social rate of interest is probably not appropriate for industry and that the industrial planner "must also understand how the cost of each device fits into the financial structure of their business."[31] For San Juan, S&L used an interest rate of 8.44% and equipment life of 30 years. These values were used to be consistent with cost estimates prepared by EPA for its San Juan BART determination and to more accurately reflect PNM's capital structure. Fixed and variable O&M costs were developed for each control system. Fixed costs are independent of the level of production, and would be incurred even if the control system were shut down and include costs such as maintenance labor and materials, administrative charges, property taxes and insurance. Variable O&M costs are items that generally vary in proportion to some measure of productivity (e.g., exhaust gas processed by the control system per unit time), and include the cost of consumables, including reagent (e.g., urea or ammonia), catalyst replacement costs, by-product management, water consumption, steam and auxiliary power requirements. Auxiliary power requirements reflect the additional power requirements associated with operation of the new control technology, including operation of any new ID fans as well as the power requirements for pumps, reagent handling, and by-product handling. Variable O&M costs can also include a boiler efficiency penalty if the control system results in reduced boiler efficiency (e.g., SNCR). Both fixed and variable O&M costs were included in the SCR and SNCR cost estimates.

M. S&L Deviations from Cost Control Manual in Development of Annual Costs

The methodology S&L used to estimate total annual costs for the San Juan air quality control systems followed the methodology described in the Control Cost Manual. Fixed annual O&M costs, including annual maintenance labor and material costs, were calculated as a function of the total capital investment. Variable annual O&M costs, including reagent consumption (ammonia), auxiliary power costs, water, steam and catalyst replacement costs were calculated based on

[31] *Id.*

project-specific design parameters for the San Juan SCR control systems. Capital costs were annualized by multiplying the total capital investment by a CRF. The CRF was calculated using equation 2.55 in the Control Cost Manual[32], an interest rate of 8.44%, and useful equipment life of 30 years. This approach is consistent with the methodology described in the Control Cost Manual to calculate total annual costs. Total annual costs for each control system, including the assumptions used to calculate annual O&M costs, are summarized in Tables 6 – 8.

Table 6: San Juan Generating Station Units 1 & 4 – SNCR Total Annual Costs

Cost Item	UNIT 1	UNIT 4	Remarks/Cost Basis
Direct Annual Costs:			
Fixed Annual Costs			
Operating Labor	$0	$0	Assumed no operating labor for the SNCR
Annual Maintenance Cost	$260,900	$257,500	TCI X 1.5% Cost Manual Section 4.2, Ch, 1, Eqn.1.21
Total fixed annual costs	**$260,900**	**$257,500**	
Variable annual costs			
Reagent Consumption	$3,353,700	$6,177,200	Based on 225.2 gph (Unit 1) and 414.8 gph (Unit 4) 50% urea solution per Fuel Tech Proposal 11-B-122, Rev.1, 07-10-2012. Assumes $2.0/gal and 85% CF.
Water Consumption	$134,000	$150,100	Based on 50 gpm (Unit 1) and 56 gpm (Unit 4) per Fuel Tech Proposal 11-B-122, Rev.1, 07-10-2012. Assumes $6/1000 gal and 85% CF.
Power Requirement	$42,700	$51,000	Based on 155 kW (Unit 1) and 185 kw (Unit 4) per per Fuel Tech Proposal 11-B-122, Rev.1, 07-10-2012 and S&L BOP estimate. Assumes $37/MWh and 85% CF.
Total variable annual costs	**$3,530,400**	**$6,378,300**	
Total direct annual costs (DAC)	**$3,791,300**	**$6,635,800**	

[32] Control Cost Manual, Section 4.2, Chapter, 2 page 2-49.

Indirect Annual Costs:			
Cost for capital recovery	$1,609,000	$1,588,000	CRF at 8.44% interest & 30 year life
Total indirect annual costs (IDAC)	$1,609,000	$1,588,000	
Total Annual Cost (TAC) = (DAC) + (IDAC)	$5,400,300	$8,223,800	

Table 7. San Juan Generating Station Unit 1 & 2 - SCR Total Annual Costs

ANNUAL COST	Unit 1	Unit 2	Remarks/Cost Basis
Direct Annual Costs			
Fixed Annual Costs			
Operating Labor	$0	$0	Assumed no additional operating labor for the SCR
Maintenance Labor & Materials	$2,712,900	$3,050,400	TCI X 1.5% EPA Cost Manual Section 4.2, Ch. 2, Eqn. 2.46
Annual Emissions Testing	$25,000	$25,000	Typical annual emissions test cost
Catalyst Activity Testing	$5,000	$5,000	Typical annual catalyst activity testing cost
Fly Ash Sampling and Analysis	$20,000	$20,000	Typical annual fly ash sampling and analysis cost
Total Fixed Annual Costs	**$2,762,900**	**$3,100,400**	
Variable Annual Costs			
Reagent Consumption (Ammonia)	$1,051,000	$1,045,600	Based on 360 lb/hr NH_3 consumption rate, $785/dry ton, and 85% capacity factor (CF).
Reagent Consumption (DSI)	$22,800	$22,800	Based on 51 lb/hr hydrated lime consumption rate, $120/ton, and 85% CF.
Auxiliary & ID Fan Power	$745,800	$728,600	Based on 2,707 kW/hr auxiliary power consumption, $37/MWhr auxiliary power cost, and 85% CF
Steam Cost	$72,400	$72,400	Based on 1,556 mmBtu/hr steam @ $5/mmBtu and 85% CF.
Water Cost	$0	$0	
Catalyst Replacement Cost	$773,000	$773,000	Based on initial catalyst volume of 604 m^3, catalyst replacement cost of $8,000/$m^3$, and future worth factor of 0.48 (see, Control Cost Manual, Sec. 4.2, Ch. 2, pg. 2-47).
Total Variable Annual Costs	**$2,665,000**	**2,642,400**	
Total Direct Annual Costs (DAC)	**$5,427,900**	**$5,742,800**	

Indirect Annual Costs			
Capital Recovery Factor (CRF)	0.0925	0.0925	Calculated using 8.44% interest and 30 year equipment life
Cost for Capital Recovery	$16,737,000	$18,819,000	TCI x CRF
Total Indirect Annual Costs (IDAC)	**$16,737,000**	**$18,819,000**	
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$22,164,900**	**$24,561,800**	

Table 8. San Juan – Units 3 & 4 SCR Total Annual Costs

ANNUAL COST	Unit 3	Unit 4	Remarks/Cost Basis
Direct Annual Costs			
Fixed Annual Costs			
Operating Labor	$0	$0	Assumed no additional operating labor for the SCR
Maintenance Labor & Materials	$3,963,100	$3,539,100	TCI X 1.5% EPA Cost Manual Section 4.2, Ch. 2, Eqn. 2.46
Annual Emissions Testing	$25,000	$25,000	Typical annual emissions test cost
Catalyst Activity Testing	$5,000	$5,000	Typical annual catalyst activity testing cost
Fly Ash Sampling and Analysis	$20,000	$20,000	Typical annual fly ash sampling and analysis cost
Total Fixed Annual Costs	**$4,013,100**	**$3,589,100**	
Variable Annual Costs			
Reagent Consumption (Ammonia)	$1,632,500	$1,601,600	Based on 548 lb/hr NH_3 consumption rate, $785/dry ton, and 85% capacity factor (CF).
Reagent Consumption (DSI)	$72,400	$72,400	Based on 162 lb/hr hydrated lime consumption rate, $120/ton, and 85% CF.
Auxiliary & ID Fan Power	$1,101,800	$1,101,800	Based on 3,999 kW/hr auxiliary power consumption, $37/MWhr auxiliary power cost, and 85% CF
Steam Cost	$108,500	$108,500	Based on 2,333 mmBtu/hr steam @ $5/mmBtu and 85% CF.
Water Cost	$0	$0	
Catalyst Replacement Cost	$1,201,000	$1,201,000	Based on initial catalyst volume of 938 m^3, catalyst replacement cost of $8,000/$m^3$, and future worth factor of 0.48 (see, Control Cost Manual, Sec. 4.2, Ch. 2, pg. 2-47).
Total Variable Annual Costs	**$4,121,600**	**$4,085,300**	

Total Direct Annual Costs (DAC)	**$8,134,700**	**$7,674,400**	
Indirect Annual Costs			
Capital Recovery Factor (CRF)	0.0925	0.0925	Calculated using 8.44% interest and 30 year equipment life
Cost for Capital Recovery	$24,450,000	$21,834,000	TCI x CRF
Total Indirect Annual Costs (IDAC)	**$24,450,000**	**$21,834,000**	
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$32,584,700**	**$29,508,400**	

N. Response To NPS Comments

On July 24, 2013, NPS submitted comments on the Revised SIP to NMED. S&L provides the following response to two of the comments: The NSP comments stated, "We also note that PNM overestimated the costs of SCR. Cost estimates for SCR are significantly overestimated." S&L's capital costs are significantly higher than the cost estimates provided in the NPS Comments. In conducting its cost analysis for SCR, NPS relied on cost algorithms in EPA's Integrated Planning Model ("IPM") to estimate direct capital costs and applied the Control Cost Manual factors for indirect capital costs (NPS, pg. 3). Total capital costs estimated by the NPS using this approach were less than 50% of the total capital costs estimated by S&L. For example, NPS estimated a total capital cost of $83.7 million for SCR on San Juan Unit 1 compared to S&L's estimate of $180.9 million; and NPS estimated a total capital cost of $108.8 million for Unit 4 compared to S&L's estimate of $235.9 million. However, in our opinion, the approach used by the NPS is inconsistent with the BART Guidelines, does not result in a case-by-case cost determination and fails to properly consider costs for site-specific design challenges and site constraints that affect the cost of installing SCR control systems on the San Juan units.

The IPM model is described as a multi-regional, dynamic, deterministic linear programming model used by EPA to analyze system-wide impacts of air emissions policies on the U.S. electric

power sector in the 48 contiguous states and the District of Columbia.[33] The model has been used by EPA to analyze impacts associated with proposed regulatory programs such as the Clean Air Interstate Rule ("CAIR") and Mercury and Air Toxics Standard ("MATS"). The primary purpose of the model is to provide forecasts of least-cost capacity expansion, electricity dispatch and emission control strategies for meeting energy demand and environmental, transmission, dispatch and reliability constraints. The model includes cost modules for various air quality control technologies, and, in fact, S&L developed the cost algorithms used in the IPM model to estimate costs associated with both SNCR and SCR control systems.[34]

Cost algorithms in the IPM model provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis. By necessity, the cost algorithms were designed to require minimal site-specific information available from publicly available sources. Inputs to the IPM cost algorithms are limited to gross unit size (MW), fuel type, unit heat input or heat rate, and NOx removal efficiency. In addition, a subjective retrofit factor can be applied for control technologies installed on existing units. Because of the limited number of site-specific inputs, the IPM cost algorithms provide high-level budgetary control system costs, but do not provide case-by-case project-specific cost estimates.

Significant adjustments to the IPM cost algorithms would be needed if the algorithms were to be used to estimate project-specific costs. For example, algorithms in the IPM model were developed for a generic coal-fired power plant located at or near sea-level. However, site elevation can have a significant impact on control system sizing and design. As noted in the IPM

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[33] See, EPA website: www.epa.gov/airmarkt/progsregs/epa-ipm/.

[34] See, *IPM Model – Revisions to Cost and Performance for APC Technologies SNCR Cost Development Methodology*, Final Report, Prepared by Sargent & Lundy, LLC., August 2010. *IPM Model – Revisions to Cost and Performance for APC Technologies SCR Cost Development Methodology*, Final Report, Prepared by Sargent & Lundy, LLC., August 2010.

SCR Cost Development document dated August 2010, "elevation of the site must be considered separately and factored into the unit MW size accordingly due to its effects on the flue gas volume."[35] San Juan is located at an elevation of approximately 5,300 feet above mean sea level. At this elevation, flue gas flows will be 20-30% higher than similarly sized units at sea level. In order to accommodate for increased flue gas volume, equations in the IPM model used to calculate the base module SCR cost and base module balance-of-plant costs must be modified to accommodate the larger equipment. NPS failed to take site elevation into its cost evaluation. This modification would have a significant effect on the SCR capital cost estimate using the IPM cost equations.

IPM cost algorithms also must be adjusted to account for labor productivity in the area of the proposed project. Labor productivity is an important component of any large multi-year construction project, and is designed to account for the project location, local workforce characteristics, local unemployment and labor availability, project complexity, local climate and working conditions. It is common practice on large construction projects to apply a productivity factor to account for local worker productivity and construction site conditions. Industry experience also shows that back-fit projects and congested site conditions adversely affect labor productivity. NPS failed to adjust the IPM cost algorithms to account for regional labor productivity and to account for the fact that the San Juan SCR construction projects are retrofit projects that would require a significant amount of work in congested site conditions.

The IPM model allows the analyst to include a subjective retrofit factor for control systems installed on existing units. The retrofit factor is intended to account for site congestion and the difficulties associated with backfitting the SCR control system onto an existing unit. NPS applied

[35] *Id.*, at page 2.

a retrofit factor of 1.0 to all four San Juan units, which represents an average retrofit difficulty.[36] A retrofit factor of 1.0 does not address any of the significant retrofit challenges and site constraints that PNM must address to install SCR control systems on the San Juan units. As noted earlier in my testimony, San Juan is a very congested site. This tight configuration creates design, engineering and constructability issues and will, among other things, require PNM to demolish the existing hot-side ESPs, locate the SCRs above the existing air preheaters with the bottom of the SCRs approximately 120 above ground level, severely restrict crane selection and crane placement, and dictate the use of more expensive deep structural foundations to support the SCR structures. NPS, by using a retrofit factor of 1.0, failed to take into consideration any of these site-specific challenges, all of which will add significantly to the cost of SCR installation at the San Juan.

Finally, the IPM cost algorithms do not include an estimate of the site-specific BOP modifications needed to support successful operation of the SCR control system. BOP modifications required for the successful and safe operation of the control system must be evaluated on a case-by-case basis, and will vary significantly between existing units. For example, a plant might not have adequate margin in its fans and/or auxiliary power systems to overcome the pressure drop associated with the SCR and associated duct work. Similarly, the structural integrity of the existing boiler and duct work must be evaluated on a case-by-case basis to ensure existing structures can withstand the additional pressure drop.

As noted earlier in my testimony, installation and operation of the SCR control systems on San Juan Units 1 and 4 will require modifications to the FD fans, new ID fans, an economizer bypass to allow SCR operation during periods of cycling and low-load operation, structural stiffening of the existing duct work, and upgrades to the auxiliary power systems. Other BOP costs that NPS

[36] See e.g., *NPS SCR CCM w IPM SAN JUAN #1.xlsx*, "IPM Capital Costs" worksheet, cell D6.

failed to include in its cost estimate include baghouse ash handling system upgrades (required because the de-energized hot-side ESPs must be removed) and DSI injection control to keep sulfuric acid mist emission increases below the applicable Prevention of Significant Deterioration ("PSD") significant levels. All of these costs are directly related to the installation and operation of SCR at San Juan, and will add significantly to the project costs. NPS failed to account for any of these BOP costs in its capital cost estimate.

The NPS also stated "We believe that it is feasible for San Juan to achieve 0.04 lb/mmBtu on an annual average basis." To meet this limit, the SCRs must be designed to achieve controlled NOx emissions of less than 0.05 lb/mmBtu at full load steady state operating conditions to provide compliance margin during those periods of time when NOx emissions may exceed the limit (e.g., startup, shutdown, low-load cycling, and malfunction). To meet a permit limit of 0.05 lb/mmBtu, S&L's SCR design criteria included a design target NOx emission rate of 0.03 lb/mmBtu. The design target emission rate represents the actual controlled NOx emissions under new and clean conditions operating at full load. Operating history at existing coal-fired facilities suggests that an operating margin of approximately 0.02 lb/mmBtu between the control system design target and the enforceable permit limit is required to provide a reasonable chance of compliance on a long-term basis.

IV. SUMMARY AND CONCLUSIONS

Control system costs prepared by S&L and submitted to NMED on April 1, 2013, including total capital costs and total annual costs, were prepared in accordance with the BART Guidelines and the Control Cost Manual. Capital costs were developed based on equipment cost estimates provided by equipment vendors for the major control system components, and unit-specific BOP costs based on conceptual design general arrangement drawings prepared for each control

system. Material quantities were taken directly from the general arrangement drawings and multiplied by unit costs available from published industry sources. Labor and installation costs were calculated based on the general arrangement drawings, taking into consideration regional labor productivity, site congestion and site-specific constructability issues. Indirect capital costs were calculated, as allowed by the Control Cost Manual, using appropriate factors to reflect the contracting strategy proposed by PNM for the projects. Annual O&M costs were calculated using a constant dollar approach based on project-specific control system design criteria and design target emission rates.

Cost estimates prepared using default factors provided in the Control Cost Manual are directed toward a study-level estimate with a nominal accuracy of ±30%.[37] Study-level estimates are generally acceptable for regulatory development, because they represent a compromise between the less accurate order-of-magnitude and the more accurate, but more costly, estimate types.[38] However, the Control Cost Manual does not mandate a study-level cost estimate, and "offers the user an opportunity for greater accuracy than that used by regulators."[39] The methodology used by S&L to prepare the SCR and SNCR cost estimates provides a more accurate estimate of the costs that PNM would actually incur to install and operate SNCR and SCR control systems at San Juan.

Control technology costs discussed herein are representative of the costs that PNM would incur to install and operate either SNCR or SCR control systems on the San Juan units. As noted previously, in 2011, PNM contracted S&L to prepare a conceptual design, project cost estimate and technical portions of an EPC specification as a preliminary step towards awarding a contract to install SCR control systems on San Juan Units 1, 2, 3 and 4. In April 2012, PNM received bids

[37] *Id.* at page 2-3.
[38] *Id.* at page 2-4.
[39] *Id.* at page 2-3.

for the SCR project from several bidders pursuant to its request of proposals (RFP). After negotiations with the bidders, PNM entered into a contract on October 31, 2012 with an EPC contractor to install the SCRs. The construction contract contained a cost estimate, and based on the indicative bid for construction, PNM estimated the total cost to install SCRs on all four units of San Juan to be between approximately $824 million and $910 million, including costs for construction management, gross receipts taxes, AFUDC, and other PNM costs.[40]

S&L's March 29, 2013 cost estimates are very much in line with cost estimates provided in the EPC contractor bid packages. These costs are significantly higher than the cost estimates relied upon by EPA in its August 2011 BART determination, and significantly higher than the cost estimates submitted by the NPS in their July 24, 2013 comments to the New Mexico Environmental Improvement Board. It is S&L's opinion that our March 29, 2013 cost estimates were prepared in accordance with the BART Guidelines, are representative of costs that PNM would incur to install NOx controls on the San Juan units, and that NMED reasonably relied on our control technology cost estimates in its May 21, 2013 revised BART determination for San Juan Revised SIP.

[40] See, PNM Form 10Q for the period ended September 30, 2012.

AFFIDAVIT OF RAJENDRA GAIKWAD, PH.D

STATE OF ILLINOIS)
)
)
COUNTY OF COOK)

I, Rajendra Gaikwad, Ph.D, Vice-President of Environmental Services for Sargent & Lundy, LLC, upon being duly sworn according to law under oath, deposes and states: I have read the foregoing testimony and it is true and accurate based on my own personal knowledge and belief.

Signed this 16th day of August 2013

RAJENDRA.GAIKWAD@sargentlundy.com

Rajendra Gaikwad, Ph.D

Subscribed and sworn to me this 16th day of August 2013.

OFFICIAL SEAL
TIRA L SEALS
NOTARY PUBLIC - STATE OF ILLINOIS
MY COMMISSION EXPIRES:05/04/15

Tira L. Seals
Notary Public

My Commission Expires:
May 4, 2015

RAJ GAIKWAD
Vice President
Environmental Services
Fossil Power Technologies

Sargent & Lundy LLC

EDUCATION

York University (Canada) – Management Studies – 1988-1989

McGill University (Canada) – Ph. D. Chemical Engineering 1985

Indian Institute of Technology (India) - M. Tech. Chemical Engineering - 1979

Nagpur University (India) - B. Tech. Chemical Engineering – 1977

REGISTRATIONS

Professional Engineer – Ontario, Canada

PROFICIENCIES

Air toxics control
GHG Emission Control
Coal gasification
Flue gas desulfurization (FGD)
Mathematical model development
Mechanical and thermal analyses
Microprocessor-based control systems
Particulate control systems
Repowering
SO_2 and NO_X technologies
Selective catalytic reduction (SCR)
3-D computational fluid dynamics (CFD)

RESPONSIBILITIES

Dr. Gaikwad is responsible for conducting and supervising conceptual studies and economic evaluations of various processes including various SO_X/NO_X control, hazardous air pollutants, particulate control, CO_2 control technologies, coal-gasification, and fluidized bed boilers. On such projects, he supervises development of simplified or detailed calculations, as well as general- and special-purpose computer codes, consistent with design and analysis requirements. Taking into consideration necessary design parameters, he recommends appropriate system and component models. He supervises all hand or computer calculations, evaluates analytical results and prepares recommendations for physical or analytical modifications to meet design requirements. Dr. Gaikwad's team provides input to the final design report in compliance with applicable codes and quality assurance requirements.

EXPERIENCE

Dr. Gaikwad has extensive process engineering experience with large number of pollution control technologies and advanced power generation processes such as integrated-gasification combined-cycle (IGCC), atmospheric fluidized bed combustion (AFBC), pressurized fluidized bed combustion (PFBC), Combined and Simple Cycle. He has also been involved in developing new processes to control SO_2 and NO_x from coal-fired power plants as part of the acid rain

control programs. He is familiar with more than 70 SO_2/NO_x removal processes, Hg control processes, particulate control processes, SCRs and with control of in-furnace NO_x using selective chemical reaction and combustion modifications. Dr. Gaikwad's responsibilities have included burner modifications to reduce NO_x and designs of SCR systems. Additionally, he has performed engineering and economic evaluations and reported on particulate control technologies, air toxics, and the SO_2/NO_x processes for simultaneously controlling SO_2 and NO_x, and particulate.

Dr. Gaikwad is S&L's expert in computational fluid dynamics (CFD). He has analyzed CFD application to several systems, including FGD, complex ductwork, recirculation water piping, stack flow, and electrostatic precipitators. Based on these analyses, he made a number of recommendations to help clients lower the cost of design by building optimally designed systems.

Dr. Gaikwad has completed a number of mechanical design reviews, bid evaluations, designs and specifications of balance-of-plant equipment, for a wide range of systems, such as all subsystems for wet and dry FGDs, electrostatic precipitators, coal handling and conveying systems, pulverizers and coal pipes, low-NO_X burners, SCR, selective non-catalytic reduction (SNCR), and pulse-jet baghouses.

As a lead project engineer on the Florida Power & Light Company partial repowering studies, he designed a hot windbox concept to use hot gases from a combustion turbine and predicted its performance. He also prepared simultaneous mass and energy balances for various advanced systems including Repowering with gas turbines, AFBC, PFBC, integrated and nonintegrated gasification and combined cycle systems.

Dr. Gaikwad has extensive experience with coal gasification combined cycle and process-oriented systems. He has been involved in developing a new process to gasify coal using high-pressure superheated steam and is intimately familiar with the coal gasification research and development work that has been carried out in the industry. He has been involved in conducting Delphi surveys for EPRI and also worked on an EPRI-sponsored study to perform an engineering evaluation of a PRENFLO gasification concept. In addition, Dr. Gaikwad has authored numerous publications on coal gasification combined cycle and related subjects. Dr. Gaikwad's process expertise extends to combustion technology where he has been involved with evaluating NO_X and SO_X reduction strategies. He is also involved in the process design of flue gas desulfurization processes.

NEW GENERATION/CO_2 CONTROL

- **NRG**

  Evaluation of CO_2 Control process at WA Parish Unit 7. Participate in Clean Coal Project implementation. (2009-to present)

- **EPA**

  Prepared a detailed evaluation of potential efficiency improvement for coal-fired power plants. (2008-2009)

- **Midwest generation**

  Evaluation of CO_2 control technologies and implications of selection of wet or dry FGD technologies. (2007-to present)

- **Oklahoma Gas and Electric**

  Supervised and participated in CO_2 control study for system-wide solution including CO_2 control technologies for existing coal-fired power plant and replacement with new generation. (2007)

- **Basin Electric**

  Performed technology selection analysis for NO_X control. Continue to support the project on air control technologies and boiler issues. (2006 to present)

- **WEPCO**

  Performed emission analysis to support the permitting of a new unit. Provided expertise and conceptual designs for multi-pollutant controls for new coal-fired power plants. (2000 to 2002)

- **Edison Mission Energy**

  Performed emission analysis to support the permitting of a new unit. Provided expertise and conceptual designs for multi-pollutant controls for new coal-fired power plants. (2000 to 2002)

- **Pinnacle West**

  Performed emission analysis to support the permitting of a new unit. Provided expertise and conceptual designs for multi-pollutant controls for new coal-fired power plants. (2001)

- **Dynegy**

  Performed emission analysis to support the permitting of a new unit. Provided expertise and conceptual designs for multi-pollutant controls for new coal-fired power plants. (2000 to 2001)

AIR TOXICS CONTROL (Hg, HCl, Non-Hg HAPS)

- **NV Energy**

  Develop utility MACT compliance plan for Reid Gardner and North Valmy stations. Develop test matrix for various technologies to comply with utility MACT (2011-to present)

- **IPL**

  Develop utility MACT compliance plan for Petersburg and Harding Street stations. Develop test matrix for various technologies to comply with utility MACT (2011-to present)

- **NRG**

  Supervised technical analysis of technologies required for Utility MACT - Hg, HCl, non-Hg HAPS, and Total PM Control (2011-to present)

- **NRG**

  Supervised technical implementation of ACI process for Indian River station. (2008-2009)

- **Midwest Generation**

  Supervised technical implementation of ACI process for various units. (2008-2009)

- **Reliant Energy**

  Performed Toxecon conceptual design for Shawville Units 1-4. (2006 to 2007)

- **Ameren UE/Ameren AEG**

  Performed mercury emission analysis and prepare compliance strategies for future regulations. (2004 to 2006)

- **Commonwealth Edison**

  Estimated relative impact of coals on particulate collection efficiency by using ESPM. (1996)

- **Carolina Power & Light Company**

  Estimated the impact of various coals on particulate collection efficiency by using ESPM model. (1993 to 1994)

- **Electric Power Research Institute**

  Evaluated the designs and costs for wet electrostatic precipitator, compact hybrid particulate collector (COHPAC) II, and electrically enhanced core separator to control fine particulates. (1993 to present)

  Evaluated particulate control options for retrofitting an existing precipitator with wide-plate spacing, taller plates, temperature-controlled electrode pre-charging, pulse-jet energization, SO3 conditioning, EPRICON, and COHPAC. (1992 to 1994)

  Evaluated high-temperature ceramic baghouse with SO_2/NO_x removal system for technical and economic feasibility. (1992)

- **Wisconsin Electric**

  Valley 1 and 2, coal, 140 MW each.

  Participated in technical bid evaluation for the installation of a first-of-a-kind pulse-jet baghouse. (1993)

  Prepared comparative designs and performance analysis for electrostatic precipitator, electrostatic precipitator with SO_3 conditioning, and pulse-jet baghouse.

- **Tosco Refining Company**

  Prepared conceptual design of pulse-jet baghouse for sodium-bicarbonate injection to control sulfur dioxide. (1992)

MULTI-POLLUTANT CONTROL (Hg, SO_2, NO_X, Particulate)

- **CPS Energy**

  Evaluate Multi-pollutant Control Strategy for NOx and Hg. Provide support during implementation (2007-2010)

- **MIDWEST GENERATION EME, LLC**

  Oversaw conceptual designs for Powerspan's processes for control of SO_2 only, SO_2, NO_X, and Hg, and CO_2. (2006, 2008- to present)

- **MIDWEST GENERATION EME, LLC**

  Oversaw all process conceptual design for installation of SCRs, FGD systems, baghouses, and activated carbon injection systems at Fisk, Crawford, Joliet, Powerton, Waukegan, and Will County Stations. (2005)

- **Montana-Dakota Utilities**

  Performed technical and cost analysis for a system-wide compliance for possible controls on SO_2, NO_X, and mercury for future regulations including North Dakota lignite-fired units. (2004)

- **AMEREN UE**

  Performed technical and cost analysis for a system-wide compliance for possible controls on SO_2, NO_X, and mercury for future regulations. Provide support during implementation. (2003 to 2009)

- **AMEREN UE**

  Process consultant for Ameren proposal to Department of Energy involving demonstration of the Powerspan Electrocatalytic Oxidation Process at the Sioux Station. (2003)

- **AMEREN Energy Generating**

  Performed technical and cost analysis for a system-wide compliance for possible controls on SO_2, NO_X, and mercury for future regulations. (2003 to 2005)

- **Electric Energy Inc.**

  Performed technical and cost analysis for a system-wide compliance for possible controls on SO_2, NO_X, and mercury for future regulations. (2004 to 2009)

- **CINERGY**

  Performed technical and cost analysis on individual units for possible controls on SO_2, NO_X, particulate, and mercury. (2002 to 2004)

- **PacifiCorp**

  Performed technical and cost analysis on individual units for possible controls on SO_2, NO_X, particulate, and mercury. Evaluated low cost solutions for NOx, SO_2, and Hg control. (2002 to 2003)

- **Public Service Electric and Gas Company**

  Performed technical and cost analysis on individual units for possible controls on SO_2, NO_X, particulate, and mercury. Evaluated low dust SCR concept. (2000 to 2002)

- **US Gen**

  Performed technical and cost analysis on individual units for possible controls on SO_2, NO_X, particulate, and mercury. Providing expertise in design of multi-pollutant system. (2000 to 2003)

NO_x and SCR

- **Confidential Clients (various)**

  Perform SCR retrofit feasibility studies in response to EPA's FIP call for NOx. (2012 to present)

- **PNM**

  Prepared conceptual design for SCR at San Juan station. Oversaw various studies related to SCR. Participating in project implementation. (2011 to present)

- **SRP**

  Prepared conceptual design for SCR at Coronado station. Oversaw various studies related to SCR. Participating in project implementation. (2010 to present)

- **Duke Energy**

  Prepared conceptual design for SCR at Cayuga Units 1 and 2 and Marshall Unit 4. Oversaw various studies related to SCR. Participating in project implementation. (2010 to present)

- **PacifiCorp**

  Prepared conceptual design for SCR at Naughton station, Jim Bridger Units 3 and 4. Oversaw various studies related to SCR. Participating in project implementation. (2009 to present)

- **Xcel Energy**

  Prepared conceptual design for SCR at Hayden Units 1 and 2; and Pawnee Unit 1. Oversaw various studies related to SCR. Participating in project implementation. (2011 to present)

- **City of Lakeland**

  Prepared conceptual design for SCR. Oversaw various studies related to SCR. Participating in project implementation. (2006 to 2009)

- **Tampa Electric**

  Oversaw various studies related to SCR installations on Big Bend Units 1-4. Issue related to fuel impact, fly ash sale, and wastewater impacts were studied. Participated in the flow model testing and eye-witnessed the adequacy of the flow modeling to meet the required design criteria. (2005 to 2010)

- **Luminant**

  Prepared conceptual designs for SCRs for lignite and PRB coal fired units. Provided inputs in the development of cost estimates. (2005 to 2006)

  Prepared conceptual designs for in-duct SCRs for Martin Lake and Monticello units. Provided inputs in the development of cost estimates. (2007 to 2009)

  Participating in pilot-scale testing of SCR on lignite-fired units. (2005 to 2009)

- **NRG Texas**

  Evaluated NOx control technologies for Limestone Station and gas-fired units. (2006)

- **Reliant Energy**

  Provide expertise in SCR system design for retrofit on a combined cycle unit at San Jacinto Station. (2003 to 2004)

- **Basin Electric**

  Prepared a low-dust vs. high-dust SCR report for PRB-fired new units. Participating in new PRB unit design. (2005 to 2006)

- **TVA**

  Prepared conceptual designs for SCRs for John-Sevier station. Prepare the comparison for high-dust vs. tail-end SCRs with steam and natural gas heating. (2002 to 2007)

- **First Energy**

  Prepared conceptual designs for SCRs for coal fired units. Provided inputs in the development of cost estimates. (2005)

- **Santee Cooper**

  Provide expertise in SCR system design for retrofit on a combined cycle unit at Rainy Station. (2003 to 2004)

- **Reliant Energy**

  Performed system-wide analysis for NO_X control. Prepared conceptual designs for SCRs for gas- and coal-fired units. A number of studies are being performed to facilitate the installation of SCRs.

  Evaluated high-dust vs. low-dust SCR concepts for PRB-fired units.

  Acting as environmental lead on all 12 SCR projects. Providing technical expertise in the design of SCR systems. (1999 to 2004)

- **Lansing Board Water & Light**

  Performed systemwide analysis for NO_X control. Prepared conceptual designs for SCRs for coal-fired units. (2000 to 2001)

- **Southern Illinois Power Cooperative**

  Performed cyclone overfire air analysis with the help of ANSYS. Recommendations include the locations of ports and the NO_X predictions. (2001)

- **Austin Energy**

  Performed systemwide analysis for NO_X control. Performed the repowering analysis. (2000 to 2001)

- **Tampa Electric**

  Prepared conceptual designs for SCRs for coal-fired units. Provided inputs in the development of cost estimates. (2000)

- **Central and Southwest**

  Prepared conceptual designs for SCRs for coal-fired units. Provided inputs in the development of cost estimates. Evaluate high-dust as well as low-dust concepts. (2000)

- **Louisville Gas and Electric**

  Performed systemwide compliance analysis for NO_X control. Prepared conceptual designs and cost estimates for SCRs for coal-fired units. (1999)

- **Western Kentucky**

  Performed systemwide compliance analysis for NO_X control. Prepared conceptual designs and cost estimates for SCRs for coal-fired units. (1999)

- **Indianapolis Power and Light**

  Performed systemwide compliance analysis for NO_X control. Prepared conceptual designs and cost estimates for SCRs for coal-fired units. Prepared FGD evaluation for Stout Unit 7. (1998 to 1999; 2002 to 2004)

- **Consumers Energy**

  Analyzed various units for the full-scale SCR retrofit. Analyzed NO_X scenarios for PM2.5. (1997 to 1998)

- **Associated Electric**

  Participated in turnkey specification preparation. (1997 to 1999)

- **Union Electric Co.**

  Analyzed various units for the full-scale SCR retrofit. (1997 to 1999)

- **Illinois Power Co.**

  Performed bid evaluation for SCR catalyst. Recommendations were made on various design issues related to SCR. (1996 to 2000)

- **Dominion Energy**

  Performed studies on NO_X control technologies, SCR retrofit at Kincaid, coal handling systems. (1996 to 1999)

FGD and SO_X/NO_X

- **AEP**

  Supervise FGD options for various power plants. (2010 – 2011)

- **ESBI**

  Troubleshooting services for the enhanced performance of CDS scrubber. (2008 to 2010)

- **Entergy**

  Performed conceptual design studies for White Bluff wet FGD, dry FGD, and SCR installation. Supervising design input from AQCS group. (2008 to present)

- **SRP**

  Performed conceptual design studies for Coronado units for wet FGD, dry FGD, and SCR installation. Supervising design input from AQCS group. (2006 to present)

- **NRG Texas**

  Prepared limestone based wet FGD and lime based dry FGD specification and conceptual studies. (2006, 2009 to 2011)

- **NRG**

  Performed conceptual design studies for Big Cajun units for wet FGD, dry FGD, and SCR installation. Prepared limestone-based wet FGD specifications. (2006)

- **Ameren UE**

  Prepared limestone-based wet FGD specification and conceptual studies. Participated in bid evaluation. (2005 to 2010)

- **Texas Genco**

  Performed SO_2 control study. Evaluated various SO_2 control technologies for WA Parish Station. Provided recommendations for suitable technology and prepared conceptual designs. (2005 to 2006)

- **Pacificorp**

  Prepared lime-based wet FGD specification and conceptual studies. Participated in bid evaluation. (2004 to 2005)

- **AEP**

  Performance Enhancement Evaluation of Existing FGD System at Oklaunion and Pirkey. (2004)

- **TVA**

  Performed SO_2 control study. Evaluated various SO_2 control technologies for number of units in TVA's system. Provided recommendations for suitable technology and prepared conceptual designs. (2002)

- **Department of Energy**

  Low Emission Boiler Systems - Analyzed various FGD systems suitable for low emissions. Prepared material balances and recommended systems for low emissions. (1996 to 1999)

- **Tanjung Jati**

  Analyzed various FGD systems. Prepared FGD specifications suitable for International Standard. (1996 to 1997)

- **Central Illinois Public Service Co.**

  Analyzed dual-alkali system and recommended modification to reduce O&M costs (1995).

- **Montana Power**

  Responsible for the evaluation of dry FGD technologies including duct sorbent injection, confined zone dispersion, NaTec and ADVACATE processes. (1994)

- **The Israel Electric Corporation Ltd.**

  Prepared material balances and sensitivity analyses for various FGD technologies, including seawater scrubbing and ammonia scrubbing. (1993)

- **TU Electric**

  Ductwork evaluation for FGD performance enhancement at Monticello Unit 3. (2004)

  Performed condition assessment of FGD units at Martin Lake and Sandow Power Generating Units. Performed root-cause analysis for these FGD systems. (1994)

Developed strategy for SO_2 emission control for compliance with the 1990's CAAA and prepared budgets to incorporate the least-cost strategy for SO_2 compliance. Trained client personnel in the use of EPRI's Clean Air Technology Workstation. (1993)

- **Kentucky Utilities Company**

  Performed evaluation of various technologies. Developed a methodology for evaluation for the engineering analysis. Prepared mass balances and process selection position paper.

  Participated in bid evaluation. Performed unsteady state chloride analysis. (1991 to 1993)

- **Owensboro Municipal Utilities**

  Performed economic evaluation of various technologies. Developed position papers on process selection, reagent preparation, and waste disposal systems. Prepared equipment lists, mass balances, and specifications. (1991 to 1993)

- **Electric Power Research Institute**

  Engineering evaluation of combined NO_x/SO_2 processes. Performed conceptual process design and developed specifications, process and instrument diagrams, heat and mass balances, and cost estimates; identified research and development required to bring process to commercial viability. (1989 to 1993)

- **Carolina Power & Light Company**

  - Mayo 1, coal, 745 MW;
  - Roxboro 2-4, coal, 2077 MW total.

  Prepared conceptual process flow diagrams, mass balances, equipment list, and cost sensitivity analysis. Conducted special studies on chloride effects and sensitivity to SO_2 removal on design and performance of FGD system. (1992, 1996, 1999)

- **Electricity Corporation of New Zealand**

  Performed comprehensive study to evaluate various SO_2 control technologies, impacts on generation and future trends. (1992)

- **Houston Lighting & Power Company**

  Absorber tray retrofits SO_2 removal performance predictions. Performed detailed calculations to replace Di-Basic FGD enhancement system with absorber trays. (1989 to 1990)

3-D COMPUTATIONAL FLUID DYNAMICS

- **Oversees a number of CFD projects – 2004 to present**
- **Ameren**

  Performed flow analysis for air heater baffle to lower pressure drop and erosion. (2001)

- **Cinergy**

  Performed flow analysis for SCR outlet duct to propose flow-guiding vanes. (2000 to present)

- **Reliant Energy**

  Performed flow analysis for SCR inlet and outlet ducts to propose flow-guiding vanes. Performed particle trajectory analysis to evaluate the impact of ash deposition. (2000 to present)

- **Illinois Power Co.**

  Performed flow analysis for air heater inlet and outlet ducts suitable for SCR retrofit. Performed the analysis for ESP inlet to evaluate the requirement of flow guiding vanes. (1997 to 1998)

- **Unocal Refinery**

  Performed flow analysis for baghouse inlet ductwork. (1996)

- **Commonwealth Edison**

  Performed flow stratifications study by using computational fluid dynamics. (1996)

- **PacifiCorp**

  Performed flow analysis for inlet ductwork for ID fan to enhance fan performance. (1997)

- **Illinois Power**

  Performed flow analysis for ESP and recommended modifications for flow improvement. (1996)

- **TU Electric**

  Predicted velocity/temperative profiles in the FGD outlet ductwork assembly and also identified the build-up spots and mal-distribution zones. (1994)

- **Illinois Power**

  Performed boiler modeling for tangentially fired boiler. (1994)

  Predicted a recirculation zone, which could cause corrosion in recirculation pipe. (1995)

- **Tampa Electric**

  Performed open bypass analysis for chimney. Predicted the amount of gas that can be bypassed. Predicted the droplet re-entrainment in the chimney. (1995)

- **Central Illinois Public Service**

  Performed flow analysis for ESP and recommended modifications for the flow improvement. (1996)

  Performed flow analysis for Flow analysis for pre-cooler, scrubber, perforated plate, and mist eliminator. Recommended design modifications. (1995)

COAL GASIFICATION

- **LCRA**

  Performed Coal Technology Assessment for a potential new power plant. Provided expertise on coal gasification and multi-pollutant controls for new coal-fired power plants. (2003 to 2004)

- **Virginia Power**

  Developed reference plant designs for Texaco, Shell, and Dow IGCC processes; designed hot-gas clean-up, thermal integration, and partial and full integration of air separation units. (1993)

- **M-C Power Corporation**

  Participated in preparation of proposal for flue gas cleanup for fuel cells. (1992)

- **J. Makowski Associates, Inc.**

  Prepared heat/mass balances and predicted performance for petroleum coke, mixture of coke and coal and orimulsion gasification. (1992)

- **Electric Power Research Institute**

  PRENFLO-based IGCC study.

  Investigation of the advantages and disadvantages of integration of the air separation plant with the combustion turbine on a PRENFLO-based IGCC power plant. Detailed engineering work with economic analysis is being performed. (1990 to 1991)

  Policy Delphi IGCC study.

  Prepared preliminary questionnaire to assess utility concerns regarding IGCC technology. (1990)

REPOWERING AND COMBINED CYCLES

- **City of Tallahassee**

  Conducted and supervised CO and SCR catalyst evaluation for existing combined cycle units for low load operation. (2008 - 2011)

- **Liberty Electric**

  Performed cycle analysis for combined cycle power plant with 3 different gas turbines. (1998 to 1999)

- **Pella Electric**

  Performed cycle analysis for combined cycle power plant with gas turbines. (1998-1999)

- **Zachry**

  Performed bid evaluations of various sub-systems related to combined cycle power plant. (1996 to 1997)

- **Pacific Gas and Electric Company**

  Performed heat balances and performance calculations for partial repowering of existing gas-and oil-fired boilers with the gas turbines. (1992)

- **Florida Power & Light Company**

  Partial Repowering study. Performed heat balances for steam cycles as well as repowered heat cycles using exhaust from gas turbines. Detailed performance evaluation was performed. (1990 to 1991)

  Evaluation of the combined and simple cycle power generation. Detailed calculations for performance and review of existing specifications. (1989 to 1990)

FLUIDIZED BED COMBUSTION

- **Argonne National Laboratories**

  Atmospheric fluidized bed combustion (AFBC) reference plant, 80 MW.

  Performed heat and mass balances.

  Developed a generalized spreadsheet program for heat and mass balances for AFBC plant. Prepared auxiliary power curves and incorporated curves into standards. (1990 to 1992)

- **PSI Investments**

  Performed technical review for a cogeneration facility that used fluidized bed combustion technology and a greenhouse. (1991)

  Participated in specification preparation for pulse-jet baghouse. (1992 to 1993)

BEFORE JOINING SARGENT & LUNDY

SO_2/NO_x CONTROL

- **Ontario Hydro, Toronto**

  Professional Engineer. Involved in developing new process (es) to control SO_2 and NO_x from coal-fired power plants as a part of acid-rain control program of Ontario Hydro. Designed isothermal reactor to study the effect of enhancer to improve the SO_2/NO_x removal by sorbent slurry injection. Gained expertise in controlling NO_x in-furnace via selective chemical reaction and combustion modifications. Achievements included development of solid-liquid dual fluid nozzle (patentable). Attended courses for professional advancement in Effective Writing, Communication, Advances in Combustion and Pollution Technology (The Center for Professional Advancement), Effective Consulting and Supervising, and Thinking on Your Feet. (1988 to 1989)

COAL GASIFICATION

- **SNC, Inc., Montreal (at Vancouver)/University of British Columbia**

  Project Engineer/Research Engineer. Represented SNC, Inc. on a coal gasification project co-sponsored with CCMRI China. A pilot plant was commissioned comprising a superheated steam catalytic spouted bed gasifier. Microprocessor-based control system was developed and installed. Feasibility and versatility of the process for town gas supply was effectively demonstrated. Designed and fabricated a high-pressure, low-temperature, spouted-bed multiphase reactor for hydrodynamic studies of fossil fuel gasification. Reactor was operated to optimize the hydrodynamic parameters and hydrodynamic model was developed for spouted bed coal gasifier. (1985 to 1987)

MULTIPHASE REACTOR DESIGN

- **University of Toronto**

  Research Engineer. Designed and constructed a multiphase reactor pertinent to various reactors in fermentation, hydrorefining, and metallurgical industries. Key design parameters for multiphase dispersed (oil-water-gas) reactor were experimentally evaluated and a fundamental mathematical model was developed. Isolated a phase splitting phenomenon in multiphase reactor and developed a model for multiphase dispersed system. (1987 to 1988)

COAL LIQUEFACTION

- **McGill University, Montreal**

  Research Assistant. Developed a viable technology for coal solubilization under mild conditions using ultrasonic energy. Unique multi-component solvent systems and process parameters were identified on thermodynamic and kinetic considerations. Process parameters such as catalyst, temperature, ultrasonic intensity, and frequency were evaluated to optimize the yield and to develop a mathematical model. Mechanism of solubilization was studied by advanced analytical techniques such as SEM, BET, FTIR, DSC, UV, TLC, MS, and GC-MS. Served on the research committees for projects related to biomass liquefaction, diffusion in heterogeneous catalysts, and waste water treatment. (1981 to 1985)

COMBUSTION ENGINEERING

- **Steel Authority of India, Ltd., India**

  Project Engineer. Trained for six months in chemical plant, coke oven, steel making, and finished product section. Responsibility included the developments related to thermal engineering, energy conservation and pollution control. Burners were modified to reduce NO_x pollution. Analytical models were developed to optimize cooling and heating cycles in steel processing sections. Furnaces were scanned to develop an understanding of the flow patterns and temperature profiles. Acted as technical consultant for small steel plants and attended various career development courses. Gained expertise in combustion of

gas, liquid, and solid fuels, heat transfer in boilers and furnaces, and combustion modifications to control NO_x. (1979 to 1981)

- **Indian Institute of Technology, Bombay India**

  Research Fellow. Investigated the mixing and combustion patterns in the free turbulent diffusion jets and flames (hydrogen and LPG). Mathematical model was developed to predict the shapes of flames and jets. (1977 to 1979)

MEMBERSHIPS

Association of Professional Engineers of Ontario

Indian Society for Heat and Mass Transfer

AWARDS

Special Achievement Award by Institute of Clean Air Companies for "Exceptional Contributions to the Institute and its NO_X Control Division," (2001)

PUBLICATIONS

"SCR Technology as Part of a MATS Compliance Strategy", Coal Gen, August, 2012.

"Utility Asset Impact and Technology Implications Due to the Utility MACT" Electric Power Conference, May. 2011.

"Can Utilities Rely on SCR Technology for Mercury Oxidation?" PowerGen Conference 2011, Dec. 2011.

"Evolution of ACI system Design through Lessons Learned" EPRI/Southern Co. Services ACI Workshop, Nov. 2010.

"Wet Scrubbing for PRB units as a Sensible Approach to the Future" EPRI-DOE-EPA Combined Power Plan Air Pollutant Control Mega Symposium, August-September 2010.

"Reducing CO2 Emissions through Improved Energy Efficiency" Coal-Gen Conference 2010, Aug. 2010.

"Evolution of ACI System Design through Lessons Learned", EUEC Conference 2010, Feb. 2010.

"Future of Developing Mercury Control Technologies Relative to Conventional Technologies," Coal-Gen 2007, August 2007.

"Comparison of Wet and Dry FGD for Use with Low- and Medium- Sulfur Coals," Coal-Gen 2007, August 2007.

"Hg Control Technologies – non Co-benefit Technologies," Clearwater Coal Conference Committee Meeting, June 2007.

"Life Cycle Cost Comparison of FGD Retrofit Alternatives," Plant Design and Operating Committee Meeting, January 2005.

"FGD Reagent Selection - Lime versus Limestone, Wet versus Dry," Electric Power 2005, Chicago, April 2005.

"Operating Experience of SCRs at Texas Genco's Coal and Gas Fired Power Plants," EPRI-DOE-EPA Combined Power Plan Air Pollutant Control Mega Symposium, August-September 2004.

"Evaluating and Updating Clean Air Compliance Options Through the Use of the CAT Workstation," ICAC Forum 03, Tennessee, October 2003.

"Economics of Lime and Limestone for SO_2 Control," EPRI-DOE-EPA Combined Power Plant Air Pollutant Control Symposium: Mega Symposium, May, 2003.

"State-of-the-Art FGD Technology," Coal-Gen, Columbus, Ohio, August 2003.

"Design Challenges in the Application of High Efficiency SCR Technology to large Gas/Oil Fired Boilers," ICAC FORUM 2002 on "Cutting NO_X Emissions," February 2002.

"Reliant Energy's NO_X Reduction Program for their Houston area Generating facilities: technology Selection and Design Challenges," EPRI-DOE-EPA Combined Power Plant Air Pollutant Control Symposium: Mega Symposium, August 2001.

"Mercury Speciation and Impact of Current Controls: An Interpretation of the ICR Database," Coal-Gen, July 2001.

"Optimizing SCR Reactor Design for Future Operating Flexibility" ICAC FORUM 2000 on "Cutting NO_X Emissions," March 2000.

"Selective Catalytic Reduction: Workshop for Future Regulations," 20th Annual Electric Utility Chemistry Workshop at the University of Illinois, May 2000.

"Economic Evaluation of Controls for $PM_{2.5}$ – A Case Study," EPRI-DOE-EPA Combined Utility Air Pollution Control Symposium: Mega Symposium, August 1999.

"Impacts of Title III and IV of the Clean Air Act and the Revised NAAQS Particulate Control Strategies for year 2000 and Beyond," AIChE Meeting, 1997.

"Computational Fluid Dynamic Applications to Power Plants," Mega Symposium, EPRI/DOE/EPA, Washington DC, August 25-29, 1997 and AEA Users International Conference Chicago, October 6-10, 1997.

"Particulate Control for Year 2000 and Beyond," American Power Conference, Chicago, Illinois, April 1-3, 1997 and Mega Symposium, EPRI/DOE/EPA, Washington, DC, August 25-29, 1997.

"Computer Simulation Helps Engineers Devise Low Cost Modifications," The Chief Engineer, October 1996.

"FGD Betterment: Asset Preservation and Revenue Generation," American Power Conference, Chicago, IL, April 9-11, 1996.

"Engineering Evaluation of Novel Fine Particulate Control Technologies," EPRI/DOE International Conference on Managing Hazardous and Particulate Air Pollutants, Toronto, Canada, August 1995.

"Effect of Water Treatment Chemicals on Limestone/SO_2 Reaction in Flue Gas Desulfurization Systems," Corrosion 94 NACE International Conference, Baltimore, Maryland, 1994.

"Tougher U.S. Air Emission Regulations Lead to Advanced Flue Gas Desulfurization System Designs," Coal-Fired Power Plant Upgrade Conference, Warsaw, Poland, June 1993.

"Advances in Air Quality Control Technologies for Clean Air Act Compliance," American Power Conference, Illinois Institute of Technology, Chicago, Illinois, April 1993.

"Economic Evaluation of Electrostatic Precipitator Retrofit Options," 10th Particulate Control Symposium, EPRI/International Society for Electrostatic Precipitators, April 1993

"Trapping of Large Coal Molecules in a Coal Matrix," Ind. Eng. Chem. Res., vol. 32, No. 7, 1993.

"The Potential of Pulse-Jet Baghouses for Utility Boiler Part 3: Comparative Economics of Pulse-Jet Baghouse, Precipitators, and Reverse-Gas Baghouses," Journal of Air and Waste Management Association, vol. 43, No. 1, January 1993.

"Engineering Evaluation of Combined NO_x/SO_x Controls for Utility Application," EPRI/Environmental Protection Agency (EPA) Symposium, Washington, D.C., December 1991.

"Economic Evaluation of Particulate Control Technologies," Ninth Symposium on the Transfer and Utilization of Particulate Control Technology, EPRI, Williamsburg, Virginia, October 1991.

"Topping Cycle Partial Repowering of Steam Power Plants," Conference on Heat Rate Improvement, EPRI and the American Society of Mechanical Engineers, Scottsdale, Arizona, May 1991.

"Transitional Drop Size Distributions in Gas Agitated Liquid - Liquid Dispersions," Chem. Eng. Sci., Vol. 45, No. 8, pp. 2345-2356, August 1990.

"Hydrodynamics of Gas-Agitated Liquid - Liquid Dispersion," AICHE Journal, Vol 36, No. 5, May 1990.

"Activation and Recycling of Wastes from In-Furnace Slurry Injection Process for SO_2 Control," Symposium, EPRI and the U.S. EPA, New Orleans, Louisiana, May 1990.

"Integrated Coal Gasification Combined Cycle: Is It Competitive with a Pulverized Coal-Fired Boiler for Power Generation?" (Co-author), Sargent & Lundy Engineering Conference, Chicago, Illinois, 1990.

"Additive Injection for NO_x Control," 1989 International Symposium on Combustion in Industrial Furnaces and Boilers, the American Flame Research Committee, New Jersey, September 1989.

"Ultrasonic Extraction of Coal," FUEL, vol. 68, pp. 1227-1233, October 1989.

"Characterization of Drops and Bubbles in a Multiphase Reactor (Liquid-Liquid-Gas)," AIChE Meeting, New Orleans, March 1988.

"Phase Splitting of Pyrene-Tetralin Mixtures Under Coal Liquefaction Conditions," FUEL, vol. 67, pp. 1554-59, November 1988.

"Steam Gasification of Coal in a High-Pressure Spouted Bed Reactor," 37th Canadian Chemical Engineering Conference, Montreal, Canada, May 1987.

"Ultrasonic Extraction of Coal by Cavitation Induced Diffusion," 37th Canadian Chemical Engineering Conference, Montreal, Canada, May 1987.

"FT-i.r. Spectroscopic Analysis of Coal and Coal Extracts," FUEL, vol. 65, pp. 1254-1260, September 1986.

"Removal of Pyridine and Quinoline from Coal and Coal Extracts," FUEL, vol. 63, pp. 1468-1470, October 1984.

"Mixing and Combustion in Double Concentric Turbulent Diffusion Unconfined Flames and Jets, "Ind. J. Tech., vol. 22, pp. 373-384, October 1984.

"Effect of Ultrasonic Energy on the Extraction of Coal by Specific Solvents," Canadian Journal of Chemical Engineering, vol. 61, no. 5, pp. 697-702, October 1983.

"Effect of Ultrasonic Energy on the Extraction of Coal by Specific Solvents," 32nd Canadian Chemical Engineering Conference, Vancouver, October 1982.

"The Flammability and Fireproofing of Plastics, "Ind. Chem. Abs., vol. 1, pp. 6-11, October 1979.

REPORTS

Numerous Reports on NO_X, SO_2, Hg Compliance, Coal Gasification